CALIFORNIA ISO

California Independent
System Operator

May 11, 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-____-000
Amendment No. 60 to the ISO Tariff

Dear Secretary Salas:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Sections 35.11 and 35.13 of the Federal Energy Regulatory Commission's ("Commission") regulations, 18 C.F.R. §§ 35.11, 35.13, the California Independent System Operator Corporation ("ISO")[1] respectfully submits for filing an original and six copies of an amendment ("Amendment No. 60") to the ISO Tariff. Amendment No. 60 modifies ISO Tariff provisions related to the implementation of the Commission-imposed must-offer obligation. Amendment No. 60 benefits the ISO and Market Participants by clarifying and improving aspects of the must-offer obligation. In particular, Amendment No. 60: (1) provides for a more rational and efficient process for granting or denying waivers, (2) modifies certain payment terms and the allocation of must-offer costs in a manner more consistent with cost causation, and (3) sets forth clear conditions in which Condition 2 Reliability Must-Run ("RMR") Units are subject to the must-offer obligation. The ISO Governing Board approved the principles of this proposed ISO Tariff amendment on March 25, 2004.

[1] Capitalized terms not otherwise defined herein are defined in the Master Definitions Supplement, ISO Tariff Appendix A, as filed August 15, 1997, and subsequently revised.

I. EXECUTIVE SUMMARY

In the instant filing, the ISO proposes to implement modifications the must-offer obligation that were developed, in large measure, through an extensive and comprehensive stakeholder process. These recommendations include:

- Developing and making publicly available an operating procedure for committing generating units;
- Posting information on must-offer procurement and costs;
- Using a Security-Constrained Unit Commitment ("SCUC") application to minimize must-offer commitment costs;
- Revising the gas cost proxy used in the Minimum Load Cost Compensation ("MLCC") payment and Start-Up payments;
- Including auxiliary power as a recoverable Start-Up cost;
- Eliminating the current practice of rescinding MLCC payments when a unit provides Ancillary Services;
- Revising the timing of the must-offer waiver denial process to facilitate bidding into the Day-Ahead Ancillary Services markets;
- Clarifying Self-Commitment and its implications on MLCC payment;
- Revising how MLCC costs are allocated; and
- Establishing a framework for using Condition 2 RMR Units outside of the Reliability Must-Run (RMR) Contract.

II. BACKGROUND

A. The Must-Offer Obligation

1. Commission Orders Regarding the Must-Offer Obligation

The Commission established the must-offer obligation in an April 26, 2001 order instituting certain price mitigation measures for California. *San Diego Gas & Electric Company*, 95 FERC ¶ 61,115, at 61,354-56 (2001) ("April 26 Order"). The Commission imposed the must-offer obligation on all Generators that are parties to Participating Generator Agreements ("PGAs") and to "non-public Generators in California which currently make use of the ISO's interstate transmission grid." The Commission exempted hydro-electric generation, and determined that no unit would be required to run in violation of certificate or applicable law. The Commission determined that the must-offer obligation did not apply to capacity already committed in a bilateral agreement.

The Commission order issued on June 19, 2001 clarified that the must-offer obligation applied to Qualifying Facilities ("QFs") to the extent the QFs use the ISO transmission system and participated in the ISO's markets. *San Diego Gas & Electric Company*, 95 FERC ¶ 61,417, at 62,552-53 (2001) ("June 19

Order"). The June 19 Order reiterated that Generating Units would be subject to the must-offer obligation absent a showing that running the unit violates a certificate, would create criminal violations, or cause a QF unit to lose its QF status. *Id.* The June 19 Order further directed the ISO to create a mechanism that would allow generators to bill the ISO for emissions costs and to levy a rate over all load on the ISO's system to pay those costs. *Id.* at 62,562. The June 19 Order instituted a similar cost payment and cost recovery mechanism for Start-Up Fuel Costs. *Id.* at 62,563.

On July 20, 2001, the ISO implemented an approach to prevent all units from having to remain on at all times to meet the must-offer obligation. Under this approach, the ISO could grant a waiver of the must-offer obligation that would allow a generating unit to be shut down if the ISO determined it was not needed.

On December 19, 2001, the Commission issued two orders related to the must-offer obligation. The first order was issued on rehearing of the April 26 Order and the June 19 Order, *San Diego Gas & Electric Company*, 97 FERC ¶ 61,275 (2001) ("December 19 Rehearing Order"). The second order concerned the ISO's July 10, 2001 filing to comply with the June 19 Order. In the second order, the Commission directed that:

> ...a generator must be compensated for its actual costs during each hour when that generator is: (1) not scheduled to run under a bilateral agreement; (2) not on a planned or forced outage; and (3) running in compliance with the must-offer obligation but not dispatched by the ISO. These costs should be directly invoiced to the ISO and the ISO should recover these costs consistent with the methodology utilized for the recovery of emissions and start-up fuel costs.

San Diego Gas & Electric Company, 97 FERC ¶ 61,293, at 62,363 (2001) ("December 19 Compliance Order").

The December 19 Compliance Order affirmed the June 19 Order's directive to use the average of the mid-point of the monthly bid-week gas prices for the three spot markets reported by Gas Daily for California (i.e., the gas costs used to determined proxy prices) to determine the fuel payment for each hour that a generating unit is in minimum load status.

The Commission found the ISO's proposal to grant waivers of the must-offer obligation to be reasonable and directed the ISO to develop tariff provisions for granting exemptions of the must-offer obligation, to be effective July 20, 2001. *Id.* The Commission also conditioned payment on having the request for waiver of the must-offer obligation denied, directing that:

> [a]s proposed by the ISO under its interim operating procedures, generators must submit to the ISO a request for an exemption from the must-offer obligation. If the exemption of the must-offer obligation is granted, the generator will not qualify for minimum load costs during the period the exemption is in effect.

Id.

In its January 25, 2002 filing to comply with the December 19 Compliance Order ("January 25 Compliance Filing"), the ISO specified the process under which it would grant waivers of the must-offer obligation. The ISO also proposed to "net out" any profits realized through participation in ISO markets during the Waiver Denial Period from Minimum Load Costs such that the ISO would only pay Minimum Load costs not already recovered through market revenues in excess of costs. Transmittal Letter for January 25 Compliance Filing at 13. Further, the ISO proposed to pay Minimum Load Costs in those hours during the Waiver Denial Period except those in which: (1) an Hour-Ahead Energy Schedule or Ancillary Services Schedule or bid is submitted for that unit; (2) the unit self-provides or is awarded Ancillary Services capacity; and (3) the unit operates within a tolerance band equal to the greater of 5 MW of 3% of the unit's maximum operating output. *Id.* at 15-16. The ISO also proposed to grant waivers so as to: (1) minimize Start-Up and Minimum Load costs necessary to meet forecast Demand; (2) meet operating reserve requirements; (3) provide for a reasonable assurance of market outcomes; and (4) account for operating constraints, such as unit minimum run and off times.

The Commission issued three orders on must-offer issues on May 15, 2002. The first order, which addressed requests for rehearing of the April 26 Order, the June 19 Order, and the December 19 Rehearing Order, *San Diego Gas & Electric Company*, 99 FERC ¶ 61,159 ("May 15 Rehearing Order") denied rehearing sought by Reliant on the Commission's inclusion of the Waiver exemption procedures in the ISO Tariff. *Id.* at 61,640. That order also denied Duke's request that units operating under the must-offer obligation be paid a capacity payment (*id.)* and the ISO's proposal to "net" market profits during hours in the waiver denial period from Minimum Load Costs in the Waiver Denial Period. *Id.* at 61,641. In addition, the May 15 Rehearing Order denied requests that the gas cost index used for start-up fuel cost reimbursement reflect a daily gas index (*id.* at 61,642) as well as the request of Dynegy Power Marketing, Inc. ("Dynegy") to include intra-state gas transportation and other costs in MLCC. *Id.*[2]

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[2] The Commission noted that "...while these costs may be paid for on an energy basis, they are, by definition, demand-related costs. As such, they are ineligible for cost recovery when the unit is in minimum load status." May 15 Rehearing Order at 61,642. In the instant filing, the ISO proposes to allow recovery of <u>volumetric</u> (not demand-based) intra-state gas transportation charges.

A second order issued on May 15, 2002 regarding the ISO's January 25, 2002 Compliance Filing, *San Diego Gas & Electric Company*, 99 FERC ¶ 61,158 ("May 15 Compliance Order"), rejected the ISO's proposals to grant waivers to: (1) meet operating reserve requirements and (2) account for operating constraints, such as unit minimum run and off times (thereby rejecting the ISO's proposal regarding the minimization of start-up and Minimum Load Costs). That order also directed the ISO to notify the generator of the reason that a generator's waiver request was denied, revoked or granted, and required that any ISO determination with regard to waivers be made on a non-discriminatory basis. The order reiterated the Commission's rejection of the ISO's proposal to net profits in one hour against Minimum Load Costs in other hours. The Commission approved the ISO's application of the 5 MWh/3% Tolerance Band, and the proposal that Minimum Load Costs should be paid based on the unit's average heat rate at minimum load. The May 15 Compliance Order also noted that the ISO had agreed (in a March 4, 2002 Answer to Protests of the January 25 Compliance Filing) that merely submitting bids in an hour would not cause the forfeiture of Minimum Load Costs in that hour.

The May 15 Compliance Order cited the December 19 Compliance Order's directive that the ISO should compensate a generator for its actual costs when it is "operating at minimum load status." *Id.* at 61,631. The Commission also noted that "payment of Minimum Load Costs was not intended to serve as a disincentive for generators to either bid into the Imbalance Energy market or to enter into sales in the bilateral spot market, but rather was intended to make available to the market uncommitted energy and thus prevent any withholding." *Id.* at 61,632. Further, the Commission directed that the ISO is "to pay Minimum Load Costs in each hour when a generating unit is under the Must-Offer Obligation." *Id.*

The third order issued on May 15, 2002 exempted all RUS-financed cooperatives from the must-offer obligation to the extent they did not participate in the ISO spot market, clarified that all sellers must offer available generation on a non-firm basis, and denied rehearing regarding (1) implementation of market-based solutions and (2) recovery of actual costs. *San Diego Gas & Electric Company,* 99 FERC ¶ 61,160 (2002).

The ISO submitted a filing to comply with the May 15 Compliance Order and May 15 Rehearing Order on June 24, 2002 ("June 24 Compliance Filing"). In that filing, the ISO proposed that a unit that had submitted a Day-Ahead Energy Schedule for any hour in a day be deemed Self-Committed (and therefore ineligible to recover Minimum Load Costs) in that day. Transmittal Letter for June 24 Compliance Filing at 3-4.

On October 31, 2002, the Commission issued an order on the ISO's June 24, 2002 Compliance Filing. *San Diego Gas & Electric Company*, 101

FERC ¶ 61,112 (2002) ("October 31 Order"). The Commission rejected the ISO's proposal to deem a unit self-committed for an entire day if it submitted a Day-Ahead Energy Schedule for any hour in that day. *Id.* at P 7. The order affirmed the application of the Tolerance Band to condition the payment of Minimum Load Costs when a unit is operating at its minimum load. *Id.* at P 12. The order also directed the ISO (1) to include more specific information on the timing of the waiver review and notification process (*id.* at P 16); (2) to clarify how it would treat generators running at minimum load and dispatched to provide imbalance energy (*id.* at P 11); and (3) to revoke Minimum Load Costs from any generator providing Ancillary Services in that hour (*id.* at P 12). This order also agreed with Mirant's contention that Minimum Load Energy should be forward Scheduled. *Id.* at P 13.

On December 2, 2002, the ISO submitted a compliance filing proposing that Minimum Load Energy would be paid the Uninstructed Imbalance Energy price, and any energy dispatched above the Minimum Load Level would be paid the instructed Imbalance Energy Price. The compliance filing was intended to respond to the Commission's directive in the October 31 Order that the ISO clarify how minimum load energy and energy dispatched above minimum load would be treated.

On March 13, 2003, the Commission issued an order on the ISO's December 2, 2002 Compliance Filing. *California Independent System Operator Corporation*, 102 FERC ¶ 61,285 (2003) ("March 13 Order"). This order rejected the ISO's proposal to pay minimum load costs at the uninstructed price and instructed imbalance energy at the instructed price. The order also directed the ISO to explain the operation of two Tariff provisions: one that indicated that "[t]he Waiver Denial Period shall be extended as necessary to accommodate generating unit minimum up and down times," and a second providing that "Self-Commitment Periods shall determined from Day-Ahead Schedules will be extended by the ISO as necessary to accommodate generating unit minimum up and down times such that scheduled operation is feasible." *Id.* at PP 11, 13.

On April 14, 2003, the ISO submitted a filing to comply with the March 13 Order. The ISO proposed to apply the Tolerance Band to condition Minimum Load payments to energy dispatched above minimum load.

On November 14, 2003 the Commission issued an order on the ISO's April 14, 2003 Compliance Filing. *California Independent System Operator Corporation*, 105 FERC ¶ 61,196 (2003) ("November 14 Order"). In that order, the Commission rejected the application of the Tolerance Band to energy dispatched above minimum load. The Commission also directed the ISO to modify its Tariff to show that a generator that forward-schedules its minimum load energy will still be paid its minimum load costs.

The ISO submitted a compliance filing on December 15, 2003 in which the ISO proposed to create a mechanism by which generators could schedule minimum load energy. Simultaneously, the ISO filed for rehearing and requested a stay of the provisions of the November 14 Order that would require the ISO to forward schedule the minimum load Energy.

2. MD02 Orders Pertinent to the Must-Offer Obligation and the Instant Filing

Over the past few years, the ISO has been actively pursuing a comprehensive resign of its market structure. The Commission's orders on the ISO's proposed market redesign have influenced certain of the proposals set forth herein, in particular the use of SCUC to minimize must-offer commitment costs.

On May 1, 2002, the ISO submitted a proposed market redesign ("MD02") in Docket No. ER02-1656. The ISO proposed to retain, but narrow, the must-offer obligation to non-hydroelectric generating units within the ISO Control Area. In addition, the ISO proposed to replaced the must-offer waiver process with a Residual Unit Commitment ("RUC") system, which would use a Security-Constrained Unit Commitment software application to commit units based on reliability and cost. Must-offer generators would be required to bid available capacity into the RUC process, or the ISO would insert cost-based proxy bids for them, similar to how the ISO generates cost-based proxy bids into the real-time Imbalance Energy market for units that do not comply with the must-offer obligation.

On July 17, 2002, the Commission issued an Order on the proposed market redesigns filed by the ISO on May 1, 2002 in Docket No. ER02-1656. *California Independent System Operator Corporation*, 100 FERC ¶ 61,060 (2002) ("July 17 Order"). That Order rejected the ISO's proposed RUC process but extended the must-offer obligation and the must-offer waiver process indefinitely beyond the proposed expiration date of September 30, 2002.

On October 11, 2002, the Commission issued an order on rehearing of the July 17 Order and the ISO's August 16, 2002 and August 22, 2002 filings to comply with the July 17 Order. *California Independent System Operator Corporation*, 101 FERC ¶ 61,061 (2002) ("October 11 Rehearing Order"). In that order, the Commission determined the ISO could make a filing pursuant to Section 205 of the FPA to incorporate economic criteria as a secondary consideration to reliability into the must-offer waiver process. *Id.* at P 72 ("once reliability has been ensured, it would be reasonable for the CAISO to use economic considerations in deciding which units will be granted must-offer waivers (i.e., granting waivers to the highest cost units")).

3. Relevant Orders Regarding MD02 Phase 1B

On July 22, 2003, the ISO submitted proposed Tariff Amendment No. 54. Among other things, Amendment No 54 proposed to modify how Minimum Load Energy would be treated when the market modifications needed to implement the ISO's new real-time economic dispatch application were in place as part of the Phase 1B MD02 redesign. Under Phase 1B, minimum load energy would be deemed to be instructed Imbalance Energy and paid the relevant instructed Imbalance Energy price. If that price was less than the unit's Minimum Load Cost, the ISO would also pay an uplift payment so as to pay the Minimum Load Cost. Minimum Load Energy would not be scheduled, but would be deemed to be instructed Imbalance Energy. This would eliminate the current double payment, in which Minimum Load Energy is paid both the Minimum Load Cost payment and the uninstructed deviation payment.

On October 22, 2003, the Commission issued an order on Amendment No. 54 approving the ISO's proposed treatment of Minimum Load Costs under MD02 Phase 1B. *California Independent System Operator*, 105 FERC ¶ 61,091, at PP 100-04 (2003) ("October 22 Order"). Several parties sought rehearing regarding to the treatment of minimum load costs.[3] The instant filing retains the methodology proposed by the ISO in Amendment No. 54 and approved by the Commission in its October 22 Order.

B. RMR Condition 2 Issues

In August 2003, the ISO called a Condition 2 RMR Unit out-of-market to start-up to address a system-wide reliability issue.[4] The owner of that unit refused the ISO's instruction. Recognizing the limitations of the RMR Contract (which allows the ISO to dispatch the unit under the RMR Contract only for local reliability service and to provide Ancillary Services), but urgently needing to commit the required unit, the ISO subsequently called the unit on under its RMR Contract, and the owner complied. Both the owner and the ISO contacted Commission Enforcement Staff to report the incident. After working with both parties to try to resolve this issue, on September 3, 2003, Commission Staff held a technical conference in Washington, D.C. to discuss the use of Condition 2 RMR Units for purposes other than local reliability. At that meeting, the ISO presented a proposal for using Condition 2 RMR Units for reliability purposes outside the RMR Contract. Market Participants attending that conference

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[3] The parties that sought rehearing were Duke Energy North America, LLC, Duke Energy Trading and Marketing, LLC, Dynegy Power Marketing, LLC, El Segundo Power, LLC, Long Beach Generation LLC, Cabrillo Power I LLC, Cabrillo Power II LLC, Williams Power Company, Inc., the Western Power Trading Forum, Independent Energy Producers of California, Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc.

[4] Had the problem been a local reliability problem, the ISO would have called the unit under its RMR Contract.

indicated that they could not respond to the ISO's proposal for using Condition 2 RMR Units outside of the RMR Contract because they did not know to what extent the ISO would use such units, nor did they fully understand how the ISO was granting waivers of the must-offer obligation. As a result, the ISO agreed to convene a stakeholder process to examine how the must-offer obligation was being implemented with respect to Condition 2 RMR facilities.[5] The instant filing addresses the issues that were raised at the September 3, 2003 technical conference.

C. Stakeholder Process

The ISO held an extensive stakeholder process that began in late September 2003 and continued through March 2004. The ISO held conference calls with Market Participants on September 24, 2003 and October 1, 2003 to provide a forum for them to discuss issues that Market Participants had pertaining to the must-offer requirement and self-commitment as set forth in Section 5.11.6 of the ISO Tariff. The ISO hosted stakeholder meetings on October 8, 2003, October 27, 2003, November 19, 2003, January 16, 2004, and March 10, 2004 to discuss must-offer issues and to try to develop consensus as to what modifications should be made to the must-offer process. At the request of stakeholders, representatives from the ISO, Pacific Gas and Electric Company ("PG&E"), and the Independent Energy Producers developed and posted a matrix of issues for participants in the stakeholder process to comment on. The initial matrix was later consolidated, and parties in the stakeholder process submitted their final positions to the ISO on April 5, 2004. This final matrix is posted on the ISO Home Page[6] along with all other materials from this stakeholder process, and is included as Attachment C to the instant filing.

To respond to concerns raised by stakeholders at the March 10, 2004 meeting, the ISO posted a revised proposal on the use of Condition 2 RMR Units and a proposal for modifying the must-offer waiver process timing to its Home Page on March 17, 2004.[7]

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[5] Immediately after the September 3, 2003 technical conference, the ISO expected that the stakeholder process would cover must-offer issues other than the use of Condition 2 RMR Units and that a follow-up technical conference would be held to resolve the use of those facilities. Commission staff later clarified that they did not intend to schedule such a follow-up technical conference. While the application of the must-offer obligation to Condition 2 RMR Units was briefly discussed during the stakeholder process, that process focused primarily on the other must-offer issues.

[6] The matrix is posted on the ISO Home Page at http://www.caiso.com/docs/2002/05/02/200205021545011 2004.html.

[7] These proposals are posted on the ISO's web site at http://www.caiso.com/docs/09003a6080/2e/b8/09003a60802eb820.pdf.

A draft of this proposed Amendment No. 60 was circulated to participants in the stakeholder process and posted on the ISO Home Page for comment on April 26, 2004. Comments were received back on May 3, 2004.

III. PROPOSED CHANGES

A. Transparency of the Must-Offer Waiver Process

A common stakeholder issue raised in the stakeholder process was the lack of transparency regarding must-offer use, processes, and costs. Each of these concerns is discussed below.

1. Use of must-offer waivers to meet local reliability requirements

In the stakeholder process, the ISO acknowledged that when a local reliability requirement arose for which the ISO had no available or effective RMR Units to address the situation, the ISO would revoke the must-offer waiver for a unit that could meet the local need. Some stakeholders objected to this use of waivers, suggesting that the ISO should designate a generating unit as an RMR Unit when it is required for local reliability. These stakeholders argued that, unlike an RMR Contract, when a unit is called on under the must-offer obligation, the unit receives only its variable cost and no explicit contribution to fixed costs.[8]

The criteria for designating units as RMR Units were approved by the stakeholder ISO Governing Board in 1999. Units are designated as RMR Units for the next year if studies indicate they are required to meet applicable reliability criteria during the simultaneous outage of a single generating unit and a single transmission line that has the greatest affect on that local area. These studies are conducted based on anticipated peak Demand conditions for the following three years. However, other scheduled or forced outages may occur at any time throughout the year so that, at any given time, the grid is in a different configuration and experiencing different conditions than the configuration and conditions that were studied to determine which units should be designated as RMR Units. Under those circumstances, the ISO must still comply with applicable reliability criteria but may not have any RMR Units to utilize because the RMR designation criteria consider only the simultaneous outage of a single line and a single generating unit under peak load conditions. Trying to account for all the possible combinations of outages of generating units and transmission lines would likely lead to the conclusion that every generating unit on the ISO Controlled Grid is required to operate to maintain local reliability under some system configuration and set of conditions, and, consequently, that every generating unit should therefore be given an RMR Contract. Alternatively, a

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8 The unit could earn revenues above variable cost that would contribute to fixed cost recovery if its energy bids are accepted in the market.

market design in which local market power mitigation is applied uniformly and systematically, not on a contract-by-contract basis, could be applied. Ultimately, under a rigorous resource adequacy system, every unit may have some assurance of fixed cost recovery apart from that provided in an RMR Contract (and, presumably, a corresponding prohibition on exercising local market power). California does not yet have such a resource adequacy requirement.

At the January 16, 2004 stakeholder meeting, the ISO announced its intention to review the RMR designation process in 2004. In addition to asking the ISO to re-examine the RMR designation criteria, stakeholders suggested developing a short-term RMR-type contract that could be entered into when a unit not designated as an RMR Unit in the annual designation process becomes needed for local reliability due to an outage or other unforeseen condition. The ISO and stakeholders believe there is merit in exploring use of the RMR Contract or some other contractual mechanism as a means to provide revenue adequacy and local market power mitigation for units that are frequently operated to comply with reliability criteria in the interim until the issues of market power mitigation and revenue adequacy are addressed through a comprehensive resource adequacy program. Addressing this issue through contracts, whether through the RMR Contract or some other form of contract, will also bear on the capacity payment issue discussed *infra*. While some form of contract may appear to be a promising future solution, the ISO notes that a long and contentious process was required to develop the current *pro forma* RMR Contract (and the RMR designation criteria). It is reasonable to expect that a similar intensive effort will have to be expended to develop a new form of contract or new RMR criteria.

In the interim, the ISO still must comply with applicable reliability criteria. Currently, the only way the ISO can fulfill this obligation is to revoke must-offer waivers. The ISO notes that, the Commission has never suggested that units must comply with the must-offer requirement only to meet overall system needs. To the contrary, the Commission has recognized that the must-offer requirement prevents physical withholding and ensures that the ISO will be able to call upon available resources in the Real Time Market to the extent the energy is needed. May 15, 2002 Rehearing Order at 61,640. The Commission has never restricted the ISO's ability to call on units under the must-offer obligation for local reliability purposes. Rather, the Commission has merely required that all available capacity be made available to the ISO in real time unless the ISO has granted a waiver with respect to such capacity.

2. Operating Procedure

Stakeholders complained that they did not know how the ISO determines how many units will be granted or denied a must-offer waiver. More fundamentally, stakeholders did not know how much capacity the ISO required to be on-line each day, or how the ISO determines that capacity requirement.

During the stakeholder process, ISO staff presented detailed examples describing the process the ISO goes through each day to determine how much capacity is required to be on-line.[9] Additionally, the ISO agreed to develop and post an operating procedure setting forth the process by which the ISO determines the capacity procurement target.[10] The principles behind this capacity procurement target are described *infra*.

3. Information publication

Stakeholders indicated that they did not have sufficient information to assess the ISO's use of the must-offer obligation. At the time of the must-offer stakeholder process, the ISO only posted to its OASIS web site hourly total minimum load MW committed by denying or revoking waivers. As a result of the stakeholder process, the ISO has agreed to publish on OASIS, for each hour, the total number of units, total MW of minimum load, total MW capacity, and total minimum load cost for units whose waivers were revoked or denied, categorized by Zone and by the reason the unit's waiver was revoked or denied. The ISO will also publish total monthly start-up costs categorized by Zone and the reason the unit's waiver was revoked or denied. This information will be published for an entire month 30 days after the end of the proceeding month. The ISO expects to begin publishing this information in early July. However, any information that requires modifications to the settlements system to implement will not be ready for publication until the Phase 1B modifications are implemented.

B. ISO Capacity Procurement Target

1. Control Area requirements

The ISO's capacity procurement target is:

Next day's peak Demand forecast +
Mandated Operating Reserve requirements +
Capacity needed to meet local area requirements +
a "Margin"

Capacity procurement target

The "Margin" represents capacity the ISO deems prudent to be available in real time to cover (1) Demand forecast error and (2) an expected amount of generating capacity that will be forced out of service in the next operating day. If this "Margin" is available from quick-start units not already committed or scheduled to be operating, the ISO does not need to commit additional long-start

9 See example at http://www.caiso.com/docs/09003a6080/27/b2/09003a608027b2c8.pdf.
10 Draft Operating Procedure M-432C is posted at http://www.caiso.com/docs/09003a6080/29/b7/09003a608029b733.pdf.

thermal units to provide it. If quick-start units are unavailable or already scheduled and committed to meet Demand, the ISO may need to commit additional long-start units to provide this "Margin" instead. To demonstrate how significant the need to account for Demand forecast error can be, consider the ISO's experience on May 28, 2003. Because actual temperatures greatly exceeded those temperatures used to project that day's Demand the day before, the actual Demand was 5,400 MW greater than the forecast Demand. Absent some accommodation for load forecast error, the ISO will be forced to deploy operating reserve to meet Demand on those days when the Demand forecast is less than the actual Demand and will be therefore unable to maintain adequate operating reserves as required by applicable reliability criteria at times of peak Demand those days. While this load forecast error for the day cited is atypically large, and Demand forecasts can be too high as well as too low, the consequences of failing to account for potential load forecast error may be having to declare a system emergency or not serving all the Load. For reasons described in Section III.B.4 below, the ISO does not believe it is prudent, or even possible, to meet the additional capacity requirements simply by purchasing additional reserves through the Ancillary Service markets.

While the ISO will deploy operating reserves to meet Control Area balancing requirements in the short-term after a generating unit is forced out of service, if that unit does not immediately return to service, its capacity will be unavailable to serve Demand at the time of system peak Demand, should the unit trip prior to the time of system peak Demand. While the ISO maintains operating reserves to restore generation/load balance following the loss of a generating resource, the ISO also believes it is prudent to maintain a margin of additional generating capacity to account for the expected loss of generating capacity due to forced outages.

2. Assumptions regarding other types of resources

The ISO makes the following assumptions regarding the availability of generating resources:

- **Thermal generation:** The ISO determines the amount of available generation capacity based on forward schedules and outage status. Long-start units are not considered available unless they are operating at least at minimum load. The ISO assumes that a unit that submits Day-Ahead energy schedules will be on-line and operating to those schedules the next day.[11]

- **Hydro and other limited fuel generation:** All available generation is already committed through the forward market schedules; no additional real-time hydro is available. The ISO assumes that because water is generally a "take

[11] See also the discussion on Self-Commitment, Section III.C.2 *infra*.

or spill," low-cost source for electrical energy, whatever water is available for next day's use is fully utilized and scheduled in the Day-Ahead time frame.

- **Imports:** The ISO considers that all Day-Ahead import schedules are available and will be delivered, and also includes as available a forecast of additional Hour-Ahead and real-time import participation based on the last few days' experience.

- **Municipal generation:** Only the amount of municipal generation committed through forward schedules is considered available. Other municipal capacity is only available to the ISO in an emergency.

- **Wind generation:** Currently, the amount of wind capacity is subtracted from the amount of available capacity because that amount is not developed from a rigorous forecasting process and may not be dependable; under worst-case conditions, in which the wind energy does not materialize in real time, the ISO would have to meet those forward schedules through the imbalance energy market. When the forecasting process proposed in the Participating Intermittent Resource program is put into service, the ISO expects to consider the forecast amount of wind generation as available and dependable.

3. Local area requirements

As described above, where the ISO does not have an available or effective RMR Unit that can be used to address a local reliability problem, the ISO must commit a unit under the must-offer obligation to do so. The ISO may not have access to an effective RMR Unit because the specific problem that needs to be addressed is outside the RMR designation criteria. For example, the ISO does not designate RMR Units for any local area requirements that arise from transmission or generator outages that were not studied in the RMR designation process. The amount of must-offer capacity committed to address local area needs increased dramatically in 2003-2004 due to several factors, including the catastrophic failure of a 500/230 kV transformer bank at Vincent substation on March 18, 2003, and constraints imposed by an operating nomogram governing allowable total imports into Southern California.[12]

4. Limitations of the existing Ancillary Services markets

Stakeholders have questioned why the ISO does not simply purchase additional Ancillary Services to meet the ISO's capacity procurement target. The answer is that the ISO's Ancillary Services markets are not designed to provide

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12 Under the ISO's proposed modifications to how Minimum Load Costs are to be allocated, the requirements of the Southern California import nomogram would be considered a "Zonal" requirement applying to the entire Zone, because the nomogram applies to transmission lines that connect the SP15 Zone with other Zones.

for unit commitment costs.[13] Currently, the ISO does not operate a forward energy market that commits units and explicitly covers the unit's costs through the market. The ISO's Ancillary Services markets are not unit commitment markets; they are markets designed to procure unloaded capacity from units already on-line.[14] While the ISO's proposed MD02 forward market design includes three-part bids (start-up, minimum load, and energy) and a forward unit commitment process (as well as a post-forward-market RUC process), the only mechanism the ISO currently has to commit a unit and cover a unit's start-up and Minimum Load Costs is the must-offer process. Because Ancillary Services are awarded hourly, with no guarantee of a minimum quantity or number of hours, a supplier that would operate only to provide Ancillary Services would have to recover its start-up and minimum load costs through its Ancillary Services bids. Including those costs could cause the unit to not be selected in the auction. Moreover, including those costs could unnecessarily inflate the Ancillary Services' market clearing prices should a unit recovering those costs in its bid be selected as the marginal unit. The ISO supports moving to a paradigm with three-part bids and a more rigorous market-based unit commitment process, but must rely on the must-offer process to commit units until such a market is implemented.

C. Mechanics of the Must-Offer Waiver Process

1. Use of a Security-Constrained Unit Commitment application

To implement "the provision for exempting generators from the must-offer obligation"[15] in its January 25 Compliance Filing, the ISO proposed to grant waivers in such a way to minimize costs and still meet the ISO's requirements to meet residual unscheduled load and with due respect to local reliability requirements. The Commission rejected the ISO's proposal to minimize costs in the May 15 Compliance Order.[16] The Commission subsequently noted in the October 11 Order in Docket ER02-1656 that the Commission did not intend to completely exclude economic considerations from the must-offer waiver process and indicated the ISO could propose "economic considerations as a secondary

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[13] Unlike other market designs, the ISO's current market design does not provide for explicit three-part bids (start-up, minimum load, and energy).

[14] As an example of how Ancillary Service providers are required already to be on-line, ISO Tariff Section 2.5.21 sets forth that "[a]ny minimum energy input and output associated with Regulation and Spinning Reserve services shall be the responsibility of the Scheduling Coordinator, as the ISO's auction does not compensate the Scheduling Coordinator for the minimum energy output of Generating Units bidding to provide these services. Accordingly, the Scheduling Coordinators shall adjust their schedules to accommodate the minimum outputs required by the Generating units included on the Schedules."

[15] December 19 Compliance Order at 62,363.

[16] May 15 Compliance Order at 61,630.

criteria to reliability" in a later "Section 205 filing to amend its Tariff."[17] The instant filing responds to the Commission's invitation in that regard.

In the instant filing, the ISO proposes to incorporate the use of a SCUC computer application to grant, revoke, or deny waivers to minimize start-up and minimum load cost once reliability needs have been met. More specifically, the SCUC application will:

- Minimize the sum of start-up and minimum load costs for units committed through the must-offer waiver denial process. The SCUC application will minimize these for units committed for system requirements where SCUC can choose from more than one unit to satisfy its requirements. Where specific units must be committed to meet local reliability needs, the SCUC has no ability to minimize cost. Stakeholders questioned whether the SCUC application should minimize the total start-up, minimum load, and projected energy costs. The ISO intends to minimize only start-up costs and minimum load costs because the projected energy costs depends on (1) the bid price, which can vary from hour to hour at the Scheduling Coordinator's discretion and (2) the real-time energy dispatch, neither of which can be accurately predicted at the time the SCUC application is run.[18] The ISO could make assumptions about either of these inputs, but those assumptions, if incorrect, could create more inaccurate results than not including projected energy costs in the SCUC objective function;

- Use the current Zonal network model until the Full Network Model is implemented as part of the MD02 modifications. In this mode, the SCUC application will only consider two constraints – Path 15, the interface between the NP15 and ZP26 Zones, and Path 26, the interface between the SP15 and ZP 26 Zones. This means that SCUC will only commit units for two reasons: for ISO Control Area-wide requirements to meet Demand, and to ensure there is sufficient transfer capability to deliver energy from one Zone to another. Until the Full Network Model is implemented, units needed for local reliability requirements must be committed manually outside of the SCUC application based on off-line power flow analysis;

- Consider a two-day time horizon. Stakeholders questioned whether the ISO should use a one-day time horizon because some of the inputs to SCUC – such as Day-Ahead energy schedules –

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17 October 11 Rehearing Order at P 72.

18 See discussion on timing in Section III.C.3.

> are only known one day in advance, or are likely to be more inaccurate two days in advance. The ISO's experience with evaluating the SCUC application is that unless SCUC is run for a two-day horizon, the application does not commit units with longer start-up times. These long-start-up units are the units that required the ISO to develop the must-offer waiver process.

Because a significant number of units are committed under the must-offer obligation for local reliability reasons, and SCUC will not consider or optimize such units, stakeholders question if the cost and effort of implementing SCUC is justified until the Full Network Model is implemented and SCUC can evaluate local reliability concerns. Other stakeholders object to the use of SCUC because they believe the program will commit the same units repeatedly. The ISO believes that using SCUC to commit units will provide transparency, repeatability and efficiency when compared to the current first-come, first-served approach. Where the ISO can choose from a pool of units, SCUC will add efficiency because it will select the cheapest unit(s). Where a particular unit must be committed because it is the one or one of a few that can address the local need, no choice is available and SCUC would have added no benefit to that decision, which had only one possible outcome in any case.

To maximize the economic efficiency benefits provided through SCUC, the ISO will consider all units that have requested waivers when deciding which units to grant waivers to.

2. Self-Commitment

As the ISO plans for next day operations, it must make assumptions about which generating units will be in service the next day. The ISO makes these assumptions based on submitted Day-Ahead Schedules, recent operating history, and the unit's operating characteristics (such as minimum run and minimum off times). At some point, the ISO must make a final determination about whether a particular unit will be operating or not the next day so that it can take action (i.e., revoke the waiver from that unit or a similar unit) if a particular unit is needed but not operating the day. The longer the unit's start-up time, the earlier the ISO must finalize its assumption about that unit's status for the next day.

Tariff Section 5.11.6 deems a unit to be "Self-Committed" for certain hours in the next day if it submits Day-Ahead Schedules for those hours. The unit's Self-Commitment period is extended based on the unit's operating characteristics. For example, if a unit has a ten-hour minimum run time but has submitted schedules for only two hours, the unit's Self-Commitment Period is determined to be ten, not two, hours.

Pursuant to Tariff Section 5.11.6.1.1, a Must-Offer Generator is not eligible to recover Minimum Load Costs during hours in a Self-Commitment Period.

At the same time, nothing in the ISO Tariff prevents a Scheduling Coordinator from withdrawing or nullifying submitted Day-Ahead Schedules in the Hour-Ahead time frame. This can occur if a Scheduling Coordinator's Day-Ahead Demand forecast is overstated (e.g., due to a sudden change in the weather) or if the Scheduling Coordinator has found a less expensive way to serve that Demand than the resource initially scheduled.

Currently, parties have different interpretations about the requirements of Section 5.11.6. The ISO acknowledges that the language of this section is not as precise as it should be, but believes that the provision is intended to direct that once a Scheduling Coordinator has submitted a Day-Ahead Schedule, the Self-Commitment imposed by the Day-Ahead Schedule is binding, even if the Scheduling Coordinator withdraws or nullifies the Day-Ahead Schedule in the Hour-Ahead market (as it is currently permitted to do). As it currently reads, Section 5.11.6 does not allow the Scheduling Coordinator to even request a waiver for during a Self-Commitment Period, nor does it expressly grant the ISO the discretion to consider granting a waiver to a Self-Commitment Period. As a result, this could require units scheduled in the Day-Ahead Market (and therefore Self-Committed) to remain in operation even if the ISO does not require such units to operate. That creates an illogical and inefficient outcome. To remedy this situation, the ISO proposes that Scheduling Coordinators be allowed to request waivers for Self-Commitment Periods. If the unit is not required to operate, it should be allowed to shut down. All parties agree on this aspect on the filing.

However, the ISO and some Generators disagree as to whether a Scheduling Coordinator that seeks a waiver for a unit for its Self-Commitment Period (i.e., submits Day-Ahead Energy Schedules then seeks to withdraw those Day-Ahead Energy Schedules in the Hour-Ahead market) should be eligible for MLCC payments for the self-commitment period if the ISO denies the previously Self-Committed unit's waiver.

Dynegy asserts that the Commission's requirement to pay MLCC if the unit is operating under the must-offer obligation is unambiguous and applies even if the unit was previously Self-Committed. In Dynegy's view, if an owner wants to shut a unit down, and the ISO needs to keep that unit on, the ISO is required to pay MLCC regardless of when the waiver request was submitted or whether the unit was previously Self-Committed. Dynegy believes that Self-Commitment is not binding; the Self-Commitment established by submitting a Day-Ahead Schedule is nullified if the Day-Ahead Schedule is nullified in the Hour-Ahead time frame. As a result, Dynegy asserts that no unit that wants to shut off should be required to cover its own minimum load costs just because the

ISO needs the unit to remain on and assumed it would be on based on its Day-Ahead Schedules when the ISO evaluated waiver requests.

The ISO is concerned that allowing a supplier to first indicate Self-Commitment by submitting Day-Ahead Energy Schedules, then to subsequently withdraw those Schedules and the Self-Commitment and seek a waiver, would create a situation in which a unit owner could all but ensure that its unit is denied a waiver and therefore be eligible to recover MLCC. Such a situation would effectively leave the owner, not the ISO, in the position of determining which units should be on-line. The ISO must evaluate waivers far enough in advance to commit units with long start-up times (i.e., the day before the operating day) should that need arise. The ISO bases its waiver decisions on the unit's expected state of operation. When a unit submits Day-Ahead Energy Schedules, it has declared its intent to operate that next day. The ISO therefore assumes the unit is operating when it evaluates its waiver requests. If a supplier later seeks to withdraw the Day-Ahead Schedules and request a waiver, the odds are high that the ISO will have to deny the unit's waiver because the ISO already assumed the unit was operating.

Had the waiver request been submitted prior to the time when the ISO considered all waiver requests, it is possible the ISO may have granted that unit's waiver because a cheaper unit was available. Considering all waiver requests at one time rather than individually as they come in promotes consistent treatment of all suppliers. Allowing suppliers to seek a waiver after withdrawing a Day-Ahead Schedule would be unfair to other units that were granted or denied waivers based on schedules submitted in the Day-Ahead – schedules that they are not withdrawing. In that regard, if generating units that had schedules in the Day-Ahead Market were eligible to seek a waiver after previously submitting a Day-Ahead Schedule, such unit would unfairly increase its chances of receiving MLCC at the expense of all other units queued up in the Day-Ahead Market. This could happen by a unit contriving to increase its chances of obtaining MLCC by submitting schedules in the Day-Ahead Market and then canceling such schedules in the Hour-Ahead Market and then seeking a waiver. While it may seem counterintuitive that suppliers would contrive to earn MLCC, which, if accurately specified, only provides recovery of costs, MLCC provides a guarantee of cost recovery in each hour, where a unit operating in the market might voluntarily accept operating losses in some hours in order to earn offsetting profits in other hours. Earning only MLCC in some hours may not be profitable, but doing so minimizes market risk.

The ISO understands suppliers' desire to have the maximum amount of flexibility to change Day-Ahead arrangements so as to take advantage of opportunities that may arise after the Day-Ahead time frame to provide energy to their obligations at the lowest possible price. However, the flexibility suppliers seek must be balanced against the ISO's needs to plan for the next day's operations and make reasonable assumptions about which unit will be operating that day. All parties agree that a unit that is not needed for the next day should be permitted to shut down even if it did not request a waiver before the daily deadline. The ISO's proposal to allow Scheduling Coordinators to seek a waiver will allow the ISO to grant waivers to units that may have Self-Committed in the Day-Ahead time frame, but which are ultimately not required to operate. Guaranteeing that the ISO must pay MLCC for a unit that originally Self-Committed by submitting Day-Ahead Schedules, then requested a wavier after the ISO evaluated all other waiver requests, creates an incentive to submit meaningless Day-Ahead Energy Schedules to maximize the likelihood that the unit's waiver will be denied.

The ISO proposes to clarify Section 5.11.6 so that a Scheduling Coordinator may request a waiver for a unit's Self-Commitment Period. The ISO may grant the waiver. If the ISO does not grant the waiver, the Self-Commitment Periods determined from the Day-Ahead Schedules and the unit's operating characteristics (minimum run and minimum off times) still apply. As currently set forth, the ISO would not be required to pay Minimum Load Costs during a Self-Commitment Period.

3. Timing of the Must-Offer Waiver Process

As described in Section III.D.4 (b) infra, the ISO is proposing to eliminate rescinding MLCC payments when a generating units provides Ancillary Services. During the stakeholder process, Southern California Edison ("SCE") noted that the deadline for bidding into the Day-Ahead Ancillary Services market is 12 noon, while the ISO did not act on requests for must-offer waivers until 8 PM. SCE noted that eliminating rescinding MLCC when a unit provides Ancillary Services may not increase bid sufficiency in the Day-Ahead market unless this timing issue was addressed. The ISO therefore proposes to change the timing for requesting and granting must-offer waivers. The ISO proposes to move the deadline for submitting must-offer waivers from 6 PM to 10 AM. 10 AM is the current deadline for submitting Initial Preferred Day-Ahead schedules to the ISO. As per current practice, the ISO would them publish advisory Day-Ahead schedules (but not prices) at 11 AM. The ISO would act on waiver requests and notify the Scheduling Coordinators whether the waiver had been granted or denied by 11:30 AM. Scheduling Coordinators can then submit bids to the Day-Ahead Ancillary Services market (or withdraw them if their request for a waiver was granted and they want to shut down the unit) by 12 PM.

The ISO acknowledges that moving the timeline for acting on must-offer waivers may decrease the efficiency of this process, since the ISO typically has better information on expected next day conditions (including what the current day peak was) in the evening than at noon. However, this change is needed to increase the bid sufficiency in the Day-Ahead market.

D. Compensation

1. Capacity Payment

Suppliers assert that the ISO should pay a capacity payment to units that the ISO commits under the must-offer obligation. These stakeholders maintain that this capacity has a value to the ISO, a value that is not recognized because the ISO pays only a unit's variable costs and makes no contribution to fixed costs when the unit operates under the must-offer obligation. They also contend the ISO gets what amounts to "free reserves" or a "free call option" through the must-offer obligation. Such stakeholders recommend that the ISO make a capacity payment for capacity committed under the must-offer obligation. Suppliers claim the lack of a capacity payment impedes efforts towards creating a viable resource adequacy program in California because Load-Serving Entities ("LSEs") can now acquire capacity "for free" (i.e., by only paying a unit's variable operating cost, namely, start-up costs and Minimum Load Costs) by having the ISO commit the unit under the must-offer obligation and therefore have no incentive to pursue a meaningful resource adequacy program. These stakeholders point out that the Commission has already approved a market-based capacity payment that would set a market clearing price as part of the RUC process in its October 28, 2003 order on the ISO's July 22, 2003 MD02 conceptual filing[19] and urge the ISO to accelerate the implementation of RUC. Finally, suppliers relate that there are a significant number of units representing a significant amount of capacity – more than 2,000 MW – that do not have long-term contracts, either bilateral contracts or RMR Contracts, but which the ISO has been committing through the must-offer waiver denial process. These units, suppliers claim, are providing valuable service but will not be receiving any contribution to fixed costs once the Phase 1B modifications are put into effect.[20]

Suppliers are concerned about the implementation of the Phase 1B modifications because they are currently receiving two payments for the amount of Minimum Load Energy – (1) the Minimum Load Cost Compensation, and (2) the Uninstructed Imbalance Energy price. The ISO proposed to eliminate this double payment when the Phase 1B modifications proposed in Amendment No. 54 are implemented by paying the Minimum Load Energy the instructed imbalance energy price. That proposal was approved by the Commission in the October 22 Order.[21] Under the Commission-approved proposal, if the imbalance energy price is greater than the unit's Minimum Load Cost, the unit owner may keep that payment; if it is not, the ISO shall pay an uplift needed to ensure the

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[19] *See California Independent System Operator Corporation*, 105 FERC ¶ 61,140, at P 123 (2003).

[20] The ISO recently notified stakeholders that the Phase 1B modifications, most recently scheduled to be implemented on May 1, 2004, will be implemented at a later date. The new proposed date has not yet been determined and may not be prior to Fall 2004.

[21] *See* October 22 Order at PP 100-104.

unit recovers its Minimum Load Cost. Suppliers argue that eliminating the Uninstructed Imbalance Energy payment violates the Commission's prohibition against netting.[22] On December 22, 2003, the Commission granted rehearing on this issue.[23] Suppliers contend that it is urgent for the ISO to implement a capacity payment of some kind, either through market mechanisms or through contracts, to replace the Uninstructed Imbalance Energy payments that are slated to be eliminated when Phase 1B is implemented.

Other stakeholders, primarily LSEs, assert instead that the must-offer obligation was created to mitigate physical withholding and to get supply into the market. These stakeholders assert that creating a capacity payment for units committed under the must-offer obligation would reward suppliers for having exercised market power by having withheld capacity during the precipitating California electricity crisis of 2000-2001. Furthermore, they assert that there is no opportunity cost value for the capacity committed by denying must-offer waivers, because the owner would have shut the unit down absent the ISO denying the waiver request.

The ISO acknowledges that capacity committed under the must-offer obligation has value. It allows the ISO to meet its reliability obligations by ensuring that applicable reliability criteria are met. However, although capacity compensation was discussed at each must-offer stakeholder meeting, stakeholders could not reach consensus on this issue. Suppliers adamantly supported some form of capacity payment; load-serving entities adamantly opposed it. Consequently, the instant filing does not contain a recommendation for instituting a capacity payment for capacity committed through the must-offer waiver denial process. Moreover, the ISO is concerned about implementing a capacity payment at this time. The reasons for this position are as follows:

First, the ISO – and many stakeholders – are concerned of the potential for unintended consequences that could result from the hasty creation and implementation of a capacity market or a new capacity payment. Such a new market, if developed prior to the implementation of the MD02 redesign, would be built and operated on systems that will be scrapped when the MD02 redesigns are implemented. Additionally, a capacity market or some administrative capacity payment would not necessarily target fixed cost recovery to those units that do not have long-term contracts.

Second, there are some fixed cost recovery sources available for units provided capacity under the must-offer obligation. A generating unit committed under the must-offer obligation can still earn fixed cost recovery through its

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22 *See, e.g.*, the November 21, 2003 Joint Motion for Clarification or, In the Alternative, Rehearing filed by Dynegy Power Marketing, Inc, *et al.*

23 Order Granting Rehearing for Further Consideration, *California Independent System Operator Corporation*, December 22, 2003.

energy bid if it is not the marginal supplier of energy.[24] Additionally, when the ISO commits a unit for local reliability requirements, the ISO pays for any Energy dispatched from that unit at that unit's bid price, dispatching that unit out-of-sequence as necessary. In the instant filing, the ISO proposes to eliminate rescinding MLCC when a unit provides Ancillary Services. Such a change would allow Must-Offer Generators to retain all revenues from participating in the Ancillary Services markets while having their Minimum Load Costs covered by the ISO. Finally, in the instant filing, the ISO proposes to pay the greater of MCP or the unit's cost if the ISO must instruct a unit to operate above its Minimum Load operating level. If the MCP is greater than a unit's costs it will earn revenues that can be applied to fixed cost recovery.

Third, creating a capacity payment for capacity committed due to must-offer waiver denials would have collateral effects on the current markets. Any expected capacity payment would set an opportunity cost "floor" for the existing Ancillary Service markets, because suppliers would reflect the opportunity cost of selling Ancillary Services and not receiving this payment in their Ancillary Services bids. A market-based capacity payment for must-offer capacity could even discourage suppliers from bidding into the existing Ancillary Services markets altogether if they believed the must-offer capacity market would be more lucrative. That result, if realized, could nullify the incentives to bid into the Ancillary Services markets the ISO is trying to create in the instant filing by proposing to allow suppliers to earn MLCC payments when they provide Ancillary Services.

Fourth, the concept of a capacity payment is generally associated with the "reservation" of capacity. However, no specific capacity is being "reserved" under the must-offer obligation, and the ISO has no right to a specific amount of capacity under the must-offer obligation. Suppliers are free use their capacity to sell their energy in any market and to any buyer they can find. Only to the extent that suppliers have available energy in real time – energy for which there are no alternative purchasers and which cannot be sold in other markets at that time – are they obligated to make such capacity available to the ISO's Real Time Market. As the Commission has recognized on numerous occasions, the purpose of the must-offer obligation is to prevent physical withholding. The must-offer obligation is not a call option or a similar mechanism for reserving a specified amount of capacity. Accordingly, no capacity payment is warranted. Indeed, the Commission has previously recognized that, "under competitive conditions, a generator that has available energy in real time should be willing to sell that energy at a price that covers its marginal costs, since it has no

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[24] In response to Duke's request that generators be compensated for capacity reserve service when operating under the must-offer obligation, the Commission denied Duke's request, noting that if a generator is dispatched while so operating, "unless [the generator] is the marginal costs unit that sets the market clearing price, the generator will receive some contribution to fixed costs." May 15 Rehearing Order at 61,640-41.

alternative purchaser at that time." April 26 Order at 61,355-56. Given its prior statements, it is difficult to imagine how the Commission could now determine that it is appropriate to for there to be a capacity payment for must-offer energy. Indeed, the must-offer obligation has been in existence for three years without a capacity payment and the basic form of the obligation is not changing in this filing. Under such circumstances, there is no basis to suddenly find that a capacity payment is now appropriate.

Suppliers have countered the ISO's objections to creating a new capacity market by offering that the ISO could base the capacity payment on some percentage of a price set in the Ancillary Services markets, or simply by creating a fixed, administrative capacity price. Basing the payment on some percentage of an existing Ancillary Service price, however, will create incentives for suppliers to drive up the price of the reference Ancillary Service in order to increase the payment for must-offer capacity.

The ISO currently does not advocate or support creating a new capacity market or payment for capacity committed through the must-offer waiver denial process prior to the implementation of the RUC process as part of an integrated implementation of the MD02 design. The ISO is also concerned about accelerating the implementation of RUC, as some stakeholders have proposed. Implementing one part of the MD02 market design ahead of an integrated deployment would detract from the efforts to implement the entire design. The Commission has chastised the ISO for seeking to "cherry pick" market design elements in the past. The ISO believes that RUC is part of an integrated market design and should be implemented as part of that integrated design, not as a stand-alone fix.

In sum, the ISO recognizes suppliers' concerns about capacity compensation and revenue adequacy for units that are not covered by contracts. The ISO acknowledges that capacity committed through the must-offer process has a value. Though suppliers assert that the current double-payment of Minimum Load Energy constitutes a *de facto* capacity payment, the capacity should not be valued or compensated by double-paying for Minimum Load Energy. Creating new capacity markets or implementing an administrative capacity payment have consequences – some foreseen, others likely remaining to be discovered. Providing contracts that would pay for this capacity should be explored, but contracts cannot materialize overnight, and important issues outside of the contracts – such as who should be the contracting party and how the costs are allocated if the LSE is not the contracting party – remain to be solved.

2. Daily Gas Indices

In the June 19 Order, the Commission adopted the ISO's recommendation that the gas cost index used to generate proxy bids and to determine Minimum Load Cost and Start-Up Fuel Cost compensation be the average of the monthly bid-week indices for three delivery points: Malin, PG&E Citygate, and SoCal Gas (large packages).[25]

In the must-offer stakeholder process, certain entities again questioned the gas indices being used. First, they alleged that the average of three California delivery points is biased against Northern California generators because the price of gas is systematically higher at the northern delivery points. The use of the average therefore creates an un-earned windfall for generators located in Southern California, while the gas price is diluted for generators in Northern California by the lower Southern California gas index. Second, they questioned the use of monthly bid-week indices instead of daily indices. They noted that the units committed under the must-offer obligation tend to be units not under forward contract, so the gas for these units is not procured far in advance (i.e., a month ahead) but purchased instead on the spot market. They further claimed that because the number or frequency of units committed through the must-offer waiver denial process cannot be predicted, such units necessarily operate on spot gas, not forward monthly gas, arrangements.

The ISO's concern about the viability of daily gas indices, especially during the crisis of 2000-2001, led it to recommend the use of monthly bid-week price indices. The Commission Staff also expressed concern about the viability of daily indices.[26] The ISO notes that the Commission has indicated that no party, including the ISO, has yet presented information that would provide assurances that the daily gas indices are suitably free from manipulation. Subsequently, Staff has performed an extensive review of price index reporting practices and has issued a conditional recommendation[27] that all three of the indices the ISO is proposing to use, Platt's Gas Daily, NGI and Btu, be deemed to be in substantial compliance with the Policy Statement on Natural Gas and Electric Price Indices (July 2003) and subsequent clarifications to the Code of Conduct for jurisdictional sellers / holders of blanket certificates (November 2003). The ISO is also encouraged by Staff's report on current Commission actions to improve the integrity of reported price indices[28] and feels the price

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[25] June 19 Order at 62,561.

[26] *See* Final Report on Price Manipulation in Western Markets: Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Docket No. PA02-2-000 (issued March 26, 2003), at III-4, III-16. This report is available on the Commission's Web site.

[27] *See* Report on Natural Gas and Electricity Price Indices, Dockets No. PL03-3-004 and No. AD03-7-004 (issued May 5, 2004), at 60. This report is available on the Commission's Web site.

[28] *Id.* at 10-15.

reporting framework prescribed by Staff, along with Staff monitoring activities, will serve to mitigate manipulation going forward.

The ISO also notes, however, that the ISO uses a two-day average of daily gas indices to set the energy price for RMR Units. Furthermore, Schedule C to the RMR Contract specifies two-day location-specific averages of different delivery points: an average of the midpoint of the Gas Daily index for SoCal Gas, Large Packages, the BTU Daily Gas Wire index for the SoCal Border (Topock) and midpoint of the NGI Daily Gas Price index for the Southern California Border for units in SP15, and an average of the midpoint of the Gas Daily index for PG&E Citygate and the NGI Daily Gas Price index for PG&E Citygate. The gas price specified in RMR Contract Schedule C also includes a general 2% adder to cover any other miscellaneous fees and potential gas imbalance charges. To address suppliers' concerns, the ISO recommends using the gas price specified in Equation C1-8 in Schedule C to the RMR Contract for calculation of MLCC and start-up costs.

The ISO has conducted a study, presented as Attachment D to this filing, which demonstrates the shift from a monthly gas index to the daily gas price indices used in the RMR formula would not have had an appreciable effect on recent MLCC costs. Based on 2003 Minimum Load Costs, the two percent adder specified in the RMR Contract Schedules is expected to add $2.5 million in Minimum Load Costs annually.

The ISO proposes to use the same daily gas price index for determination of Start-Up and Minimum Load Costs. Using one index for these calculations will promote consistency and reduce the chance for error and dispute. Given that the ISO has been using daily gas indices in connection with RMR, it is reasonable to use such daily indices for compensation units operating under the must-offer obligation. Unlike the current system, which uses a monthly gas price index in which it is common that the same gas price is used to settle start-up and minimum load costs, using a daily index will likely mean that the gas price used to pay start-up costs may not be the same gas price used to pay Minimum Load Costs.

3. Start-Up Costs

When the Commission created the must-offer obligation, it directed generators to invoice the ISO for Start-Up Fuel Costs.[29] The cost of auxiliary power needed to run equipment until the unit has been synchronized and can furnish this power on its own was not included in the start-up cost, even though the cost of auxiliary power can contribute significantly to over start-up costs. Though the Commission has not included this cost in the start-up cost, the ISO

29 June 19 Order at 62,563.

recommends that this policy be modified. The ISO allows RMR Owners to include auxiliary power costs in start-up charges and advocates a similar treatment for all must-offer resources. Based on an examination of the RMR Contract Schedules, the ISO expects that paying auxiliary power costs will add 50% to 70% to the Start-Up Fuel Cost Charge. Because start-up payments on invoices received for the twelve months ended August 2003 totaled $2.3 million, the ISO expects that annual Start-Up costs will increase by up to $1.5 million once auxiliary power costs are included.

4. Minimum Load Costs

a) Intra-state gas transportation and Municipal use fees

In its May 15 Rehearing Order, the Commission rejected Dynegy's request to include intra-state gas transportation, franchise fees and certain taxes in Minimum Load Costs.[30] The Commission acknowledged that these costs are paid on a volumetric basis (per MMBtu of gas transported) but indicated that these costs are by definition demand-related. In the must-offer stakeholder process, suppliers indicated they did not understand the basis for the Commission's order on this issue and requested that these costs be included in the Minimum Load Costs. While the ISO does not wish to contradict the Commission's prior direction on this matter, the ISO also fails to understand the basis for not including these costs in the Minimum Load Costs. If these intra-state gas transportation and municipal use charges are truly volumetric as-incurred charges, and are not fixed charges recovered on a production basis, the ISO proposes that they be included in the Minimum Load Costs. These costs are included in the cost of energy provided under RMR Contracts.[31] Based on analysis of Minimum Load Costs for the 12 months ended October 2003, the ISO expects that adding municipal use fees will add $4.6 million annually to Minimum Load Costs.[32]

In comments on a draft of the instant filing, the California Electricity Oversight Board questioned how the ISO would verify that the intra-state gas transportation charges were volumetric and not demand-related. The ISO proposes to validate such charges by requesting that the supplier submit to the ISO the relevant gas Tariff sheets that detail the nature of the intra-state charges. Should such information not fully resolve the issue, the ISO would require the supplier to submit additional information, including certification by an officer of the company that the charge applied to that supplier. The ISO's Department of

[30] May 15 Rehearing Order at 61,642.

[31] See the *pro forma* Reliability Must-Run Schedules, Equation C1-8 (Gas), with subsequent discussion of the transportation rate on page 22. These Schedules are available on the ISO Home Page at http://www.caiso.com/docs/2001/10/15/2001101510170613815.doc.

[32] *See* "Discussion Paper on Must-Offer Waiver Denial Compensation", available at http://www.caiso.com/docs/09003a6080/29/b7/09003a608029b732.pdf, at page 6.

Market Analysis would investigate any suspected manipulation or misrepresentation.

b) Rescission of Payments for providing Ancillary Services

Currently, Tariff Section 5.11.6.1.1 indicates that

> When a Must-Offer Generator is awarded Ancillary Services in the Hour-Ahead Market or has a final Hour-Ahead [Energy] Schedule, the Must-Offer Generator shall not be eligible to recover Minimum Load Costs for such hours within a Waiver Denial Period.

To help overcome a chronic shortage of Ancillary Services bids,[33] the ISO proposes that a Must-Offer Generator would still be eligible to recover Minimum Load Costs if it is only providing Ancillary Services or dispatched by the ISO to provide imbalance energy. A Must-Offer Generator would still be ineligible to recover Minimum Load Costs if it has a forward Energy Schedule.[34]

This proposal is consistent with the evolution of the must-offer obligation from its origin to its present form. When the Commission established the must-offer obligation, a unit was not eligible to recover its costs from the ISO in any hour in which it was (1) not scheduled to run under a bilateral agreement; (2) not on a planned or forced outage; and (3) running in compliance with the must-offer obligation ***but not dispatched by the ISO***. December 19 Rehearing Order at 62,213 (emphasis added). However, in its March 13 Order, the Commission directed the ISO to submit revised Tariff sheets to

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33 Market Participants have told the ISO that in some cases their reluctance to bid into the Ancillary Services markets stems from the loss of Minimum Load Costs that would result under the current Tariff if they are awarded Ancillary Services. As discussed in Section III.B.4, the current hour-by-hour design of the Ancillary Services markets and the lack of a separate start-up and minimum load cost bid and payment means suppliers may not be awarded enough hours in the Ancillary Service markets to recover those costs. In a competitive market, including those costs in the Ancillary Service bids reduces the likelihood that the supplier will be awarded Ancillary Services. See also a presentation on Ancillary Services bid insufficiency made by ISO staff to the Market Surveillance Committee, available on the ISO Home Page at http://www.caiso.com/docs/09003a6080/2c/b8/09003a60802cb8b9.pdf.

34 At the Commission's direction in its November 14, 2003 Order (*San Diego Gas & Electric Company*, 105 FERC ¶ 61,196), the ISO proposed in a compliance filing to allow Must-Offer Generators to schedule Minimum Load Energy to special-purpose Demand ID points. Absent such a mechanism, the ISO would have no way of knowing if a forward schedule indicated that a Must-Offer Generator was providing the minimum load energy in response to a bilateral transaction, a condition under which it clearly would not be eligible to be also paid its Minimum Load Costs by the ISO. The ISO has also sought rehearing of this direction, citing the cost of implementation, the false benefits of scheduling minimum load energy, and a conflict with the Commission's October 22 Order on Tariff Amendment No. 54 (Docket No. ER03-1046) regarding treatment of minimum load costs under Phase 1B.

> ...reflect that generators operating at minimum load and dispatched for instructed energy will continue to be compensated for their Minimum Load Costs for that energy injected into the grid under minimum load conditions and will be compensated at the instructed energy price for energy dispatched above minimum load amounts.

March 13 Order at P 7. The ISO proposes to treat the provision of Ancillary Services exactly the same way by paying a generator's Minimum Load Costs when the resource does not have a forward Energy schedule and may only be providing Ancillary Services or Imbalance Energy.

The ISO currently does not commit units under the must-offer obligation solely to provide Ancillary Services. The ISO has not projected what the increase in Minimum Load Costs may be if the Commission approves this provision. The ISO notes that it is currently engaged in discussions with stakeholders about balancing the procurement of Ancillary Services in its southern and northern Congestion Zones. Given the shortage of Ancillary Services in SP15, and the fact that units in SP15 are committed under the must-offer obligation more often than units in NP15, this proposed provision, in conjunction with a move to more regional Ancillary Services procurement, could have a significant effect on Minimum Load Costs. However, the ISO believes that its proposal will have the benefit of increasing participation in the ISO's Ancillary Services markets.

c) Moving a unit to "dispatchable" minimum load

When a unit provides Ancillary Services, it must be operating at a level such that it can immediately respond to real-time dispatch instructions to increase its output. Typically, a steam turbine generating unit has an operating level where the unit can operate stably but cannot immediately respond to real-time dispatch instructions. At some times, the ISO may need a unit operating at the higher responsive level, while at other times the ISO may only need the unit operating at the lower unresponsive minimum level. Currently, if the ISO requires a unit to be operating at the higher level, the ISO instructs the unit to that level according to its bid and pays it according to that bid, even if the bid must be taken out-of-sequence.

The ISO now proposes that, when it requires the unit to be operating at the higher responsive level, that the ISO move the unit to that level and pay it the higher of its cost or the market clearing price for the range between its lowest stable minimum load and the higher operating point.

In April 22, 2004 comments submitted on the ISO's proposal to distribute procurement of Ancillary Services (and which were provided with comments submitted on a draft of the instant filing, Williams requested that the ISO clarify how the ISO intends to treat the range between the lower (manual) and (higher (dispatchable) minimum loads. As described above, the ISO will instruct the unit to the higher operating level and pay it the greater of its cost or the market clearing price for energy for this range.

Under current practice, the ISO does not apply the Tolerance Band to condition MLCC payments in intervals in which the ISO dispatches imbalance energy from a unit operating during a Waiver Denial Period. However, in subsequent intervals, after the instruction has terminated and the unit is supposed to be ramping back to its prior minimum load level, the ISO calculates the amount of energy that the unit should be producing if it ramped back to its prior minimum load operating level at the ramp rate level established in the ISO Master File. If the amount of energy produced by the unit in these subsequent intervals exceeds the sum of (1) the residual energy determined by this calculation, (2) the Tolerance Band and (3) the minimum load level, indicating that the unit is not ramping back to its prior minimum load operating point according to its ramp rate once the instruction ends, the ISO has been rescinding MLCC payments for those later intervals. The ISO believes this practice to be consistent with the Commission's directive in the October 22 and November 14 Orders (that directed the ISO not to condition MLCC on performance within the Tolerance Band in those intervals in which the ISO dispatched Imbalance Energy) and with the Commission directive in the May 15 Compliance Order that authorized the ISO to apply the Tolerance Band to condition MLCC recovery around the minimum load level.[35] In the same comments, Williams noted that it believed the ISO should not be applying this technique to rescind MLCC payments for a unit's failure to timely ramp back to its Minimum Load until the ISO implements the Phase 1B changes that allow it to account for multiple ramp rates and dead zones.

In Amendment No. 54, the ISO proposed to pay the greater of MLCC or MCP for a unit operating a "minimum load" level, whether that level is a lower (manual) minimum load, or a higher (dispatchable) minimum load. Amendment No. 54 Transmittal Letter at 30. This proposal will take effect when the ISO implements the Phase 1B modifications. The proposal in the instant filing, to pay MLCC up to P_{min} (low or manual minimum load) and then to pay the greater of cost or MCP up to the higher (dispatchable) minimum load, would be in effect from Commission approval of the proposed amendments until the Phase 1B modifications take effect.

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[35] May 15 Compliance Order at 61,632.

E. Cost Allocation

In its June 19 Order, the Commission directed that Start-Up Fuel Costs be allocated to load on the ISO system.[36] In its December 19 Order, the Commission directed that minimum load costs be allocated in a manner consistent with how Start-Up Fuel and Emissions Costs are allocated.[37] In both cases, these costs are allocated to the same constituency: metered Demand within the ISO Control Area, plus exports to other Control Areas within California.

This cost allocation methodology provides a measure of "rough justice" in which all Scheduling Coordinators are presumed to have contributed to the need in proportion to the "demand" they place on resources supplying the ISO Control Area system. This "demand" is determined to be the Scheduling Coordinator's metered Demand plus any exports serving in-state Load. However, Scheduling Coordinators who purportedly have sufficient resources to serve their own load and any exports they provide protest that they are improperly swept up in this allocation and have to pay for a problem that they do not create.

Furthermore, as described in Sections III.A.1 and III.B.3, in situations in which the ISO must commit a non-RMR unit for local reliability reasons under the must-offer obligation, the cost of this unit is similarly spread to all Scheduling Coordinators – even those that may be hundreds of miles from the local reliability need that is being addressed by the must-offer call. Figure 2 shows how the majority of capacity committed under the must-offer obligation has been committed for local requirements in recent months. Figure 3 further shows that the vast majority of units denied waivers are in SP15.

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[36] June 19 Order at 62,563.

[37] December 19 Compliance Order at 62,363.

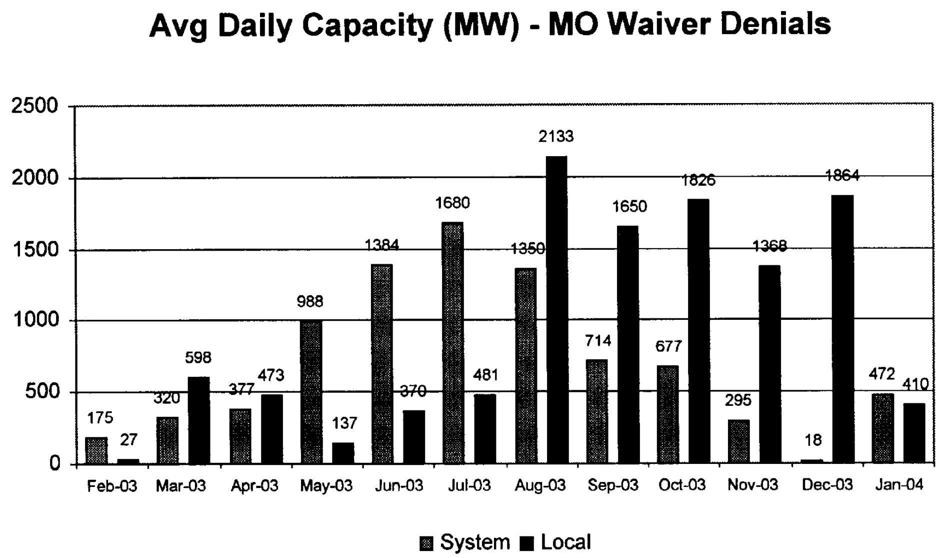

Figure 1 – Average daily Must-Offer capacity, System vs. Local requirements

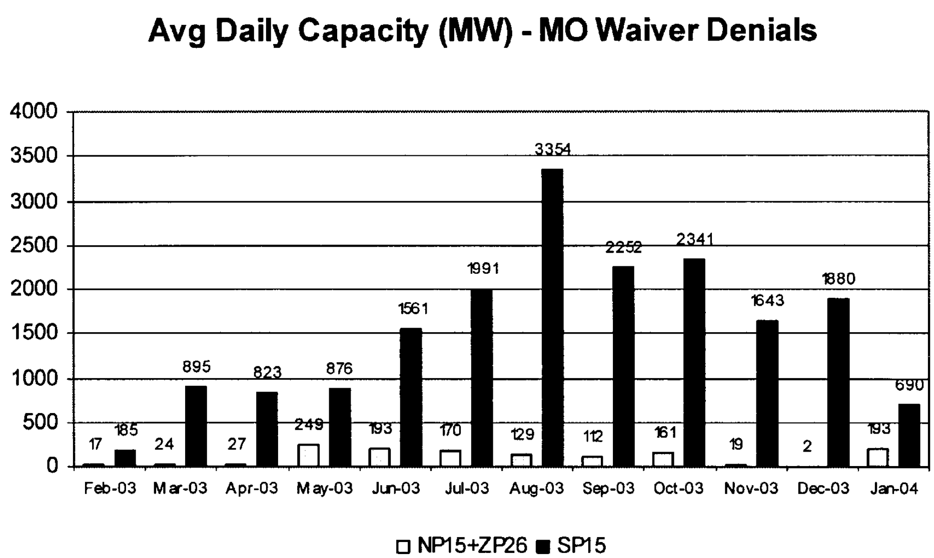

Figure 2 – Must-Offer Capacity in SP15 vs ZP26 and NP15

The ISO therefore proposes to modify the way it allocates minimum load costs to reflect the realities of how must-offer capacity is being used and to reflect better cost-causation principles. Specifically, the ISO proposes as follows:

- **Local Reliability.** Where the ISO commits and operates a unit to meet a local reliability need, the costs would be allocated to the Participating TO(s) in whose service area the unit is located. A local reliability requirement would be defined as a requirement arising due to a constraint on a transmission component that is not part of a defined active inter-zonal interface. This allocation is consistent with the way RMR costs are currently allocated.[38]

- **Inter-Zonal Congestion.** Where the ISO commits and operates a unit to provide Zone-wide benefits, or because it has no other way to manage Inter-Zonal Congestion, the costs would be allocated to Demand in the affected or Congested Zone.

- **Control-Area wide needs.** Where the ISO commits and operates a unit because of a control-area wide requirement, the ISO would allocate minimum load costs in two tiers:

1. **To Net Negative Uninstructed Deviation.** To ensure this allocation would not be excessive (i.e, where there may be significant must-offer costs but only a small amount of Net Negative Uninstructed Deviation), the ISO would first calculate a per-MWh "cap" on this rate. The cap would be determined by dividing the minimum load costs for each hour by the minimum load MW for that hour. Next, the ISO would divide the minimum load costs by the total amount of Net Negative Uninstructed Deviation to yield a similar per-MWh rate. If this rate was lower than the "cap" rate, all minimum load costs would be allocated to Net Negative Uninstructed Deviation.

2. **To Metered Demand.** If this rate exceeded the "cap" rate, the Net Negative Uninstructed Deviation would pay the "cap" rate, and any costs left over would be allocated using the current methodology – to metered Demand and exports from the ISO to in-state control areas.

Consider the following examples:

<u>Example 1</u>

Scheduling Coordinator A:
500 MW Demand
50 MW exports
30 MW of Net Negative Uninstructed Deviation

Scheduling Coordinator B:
900 MW of Demand

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[38] *See* ISO Tariff Section 5.2.8.

50 MW export
40 MW of Net Negative Uninstructed Deviation

Assume the ISO commits two units with a combined minimum load of 100 MW. Total Minimum Load Costs are $5,000.

The "capped" rate is $5,000 / 100 MW = $50/MWh.
Total Net Negative Uninstructed Deviation is 30 MW + 40 MW = 70 MW.

The total MLCC divided by the Net Negative Instructed Deviation is $5,000 / 70 MW = $71.42/MWh. Because this rate exceeds the "capped" rate, only $3,500 MW of MLCC (70 MW x the "capped" rate of $50 MWh) is allocated to Net Negative Uninstructed Deviations. The remaining $1500 is allocated both to Scheduling Coordinators pro rata based on each Scheduling Coordinator's Metered Demand and Export:

$1500 / (500 + 50 + 900 + 50) = $1 / MWh

Excess allocation for Scheduling Coordinator A = (500 + 50) x $1 = $550

Excess allocation for Scheduling Coordinator B = (900 + 50) x $1 = $950

Total for Scheduling Coordinator A = (30 MW x $50/MWh) + $550 = $2,050

Total for Scheduling Coordinator B = (40 MW x $50/MWh) + $950 = $2,950

Example 2:

Scheduling Coordinator A:
500 MW Demand
50 MW exports
50 MW of Net Negative Uninstructed Deviation

Scheduling Coordinator B:
900 MW of Demand
50 MW export
75 MW of Net Negative Uninstructed Deviation

Again assume the ISO commits two units with a combined minimum load of 100 MW. Total Minimum Load Costs are $5,000.

The "capped" rate is $5,000 / 100 MW = $50/MWh.
Total Net Negative Uninstructed Deviation is 50 MW + 75 MW = 125 MW.

The total MLCC divided by the Net Negative Instructed Deviation is \$5000 / 125 MW = \$40/MWh. Because this rate is less than the "capped" rate of \$50/MWh, all \$5000 of MLCC is allocated to Net Negative Uninstructed Deviations.

Scheduling Coordinator A = (50 MW / (50 MW + 75 MW)) x \$5,000 = \$2,000

Scheduling Coordinator B = (75 MW / (50 MW + 75 MW)) x \$5,000 = \$3,000

The ISO does not propose to change the way start-up costs or Emissions Costs are allocated. Recovering the start-up costs over a unit's operating hours would introduce substantial additional complexity for little gain, in part because to date the start-up costs are a small fraction of the minimum load costs. In that regard, for the 12-month period ended August 2003, invoiced start-up costs were \$2.3 million. Emissions costs for the same 12-month period were even less – only \$1.3 million. By contrast, Minimum Load Costs for calendar year 2003 were \$127 million.

SCE raised three issues related to cost allocation at the March 10, 2004 stakeholder meeting. First, SCE requested that the ISO indicate in its proposed Tariff language that must-offer costs related to local reliability be labeled as "Reliability Services Costs" and that the ISO indicate in its Tariff that those costs are to be recovered through SCE's Transmission Owner's Tariff. The ISO agrees that Minimum Load Costs for units committed to meet local reliability requirements are "Reliability Services Costs" and proposes to define such costs in the ISO Tariff. The ISO is reluctant, however, to try to mandate in the ISO Tariff that such costs are recoverable in another entity's Tariff.

Second, SCE requested that the ISO provide explicit criteria as to how a unit will be classified as being committed and operated for local, zonal, or system requirements. The ISO circulated to stakeholders a white paper describing how it intends to classify such costs. That white paper is included as Attachment E to the present filing. While the ISO considered creating a series of rules that would allocate the costs of unit committed for local reliability to different parties under different circumstances, the ISO now believes that the simple rule of allocating the minimum load costs to Participating TO in whose service area the unit is the best approach.

Third, SCE proposed that when a particular unit is committed for local reliability reasons, but that unit also provides system benefits, only the incremental cost of committing that particular unit over the cost of committing the cheapest available unit in the system should be allocated to the Responsible Utility. The ISO agrees that where a unit committed for local reliability requirements also meets system requirements, it is equitable to allocate only the costs of having to commit that particular unit that are in excess of the costs of a cheaper unit that would have been committed to meet system needs absent the local reliability requirement. To determine this cost, the ISO will run the unit commitment application twice. The first run will include all units needed for local requirements. Because the unit commitment application will initially only model the inter-zonal constraints (Path 15 and Path 26), the ISO will still rely on off-line engineering analysis to determine which units must be committed to meet local requirements. The second run, which uses the same ISO demand forecast used in the first run, will not commit any local units but will allow the application to commit units solely for system and zonal requirements. Subtracting the commitment costs from the second run from the commitment costs in the first run will yield the incremental costs due to the local reliability commitment. Only the incremental cost will be allocated to the Participating TOs; the commitment costs in the second (locally unconstrained) run will be allocated to the zone or to the system as described above.

Consistent with the Commission's directive, the ISO currently allocates Minimum Load Costs monthly based on Metered Demand within the ISO Control Area and exports from the ISO Control Area to Demand in California. While confirming that Minimum Load Costs are currently allocated on a monthly basis, the ISO acknowledges that Tariff Section 5.11.6.1.4 erroneously describes allocation of Minimum Load Costs on an hourly basis. Though the ISO proposes to identify the reason for the waiver denial on a Settlement Interval basis, the ISO does not propose to change from allocating Minimum Load Costs on the basis of monthly quantities to allocating costs on an hourly or Settlement Interval basis. Accordingly, the ISO proposes to revise Section 5.11.6.1.4 to conform to a monthly allocation based on the cost causation principles discussed above.

F. RMR Condition 2

The ISO designates as RMR Units certain units that, from time to time, are needed to meet reliability criteria approved by the ISO Governing Board in 1999. The *pro forma* RMR Contract allows a generator to select one of two conditions – Condition 1 or Condition 2. Condition 1 RMR Units are paid a portion of the unit's annual fixed costs and may voluntarily participate in all markets. Condition 2 RMR Units are paid their full annual fixed costs and may not participate voluntarily in any market. The *pro forma* RMR Contract limits the ISO's authority to call units under that contract to dealing with local reliability problems or providing Ancillary Services.

The ISO has encountered reliability problems that are not "local" problems (e.g., control-area supply shortfalls) that Condition 2 RMR Units could relieve. Because these problems are not "local" problems, the ISO cannot call units under the RMR Contract to address these problems.[39] The ISO therefore expects that it may, from time to time, need to operate a Condition 2 RMR Unit outside of the RMR Contract to meet system reliability requirements.

Given the limitations of the RMR Contract, which prevent an RMR Unit for which the RMR Owner has elected Condition 2 from voluntarily participating in a "Market Transaction,"[40] the only practical way for the ISO to request service from a Condition 2 RMR Unit outside of the RMR Contract is through an out-of-market call. An out-of-market call has no bid associated with it. Under Section 11.2.4.2 of the ISO Tariff, units that are called this way are paid either (1) the Hourly Ex Post Price, or (2) a formula price based on recent ISO capacity and energy prices, depending on the owner's election. The default option is the Hourly Ex Post Price. No unit owner has elected option (2).

When the ISO called upon Condition 2 RMR Units to provide service outside of the RMR Contract in August 2003, the owner of those units refused to provide such service unless the ISO called the units under the RMR Contract. Under the current payment provisions, there is a risk that the Hourly Ex Post Price might not cover the unit's variable operating costs (while such costs are covered under the RMR Contract). The owner also asserted that Condition 2 RMR Units could not operate outside of the RMR Contract because the RMR Contract only allowed the units to be used in accordance with the terms of the RMR Contract and not for system needs. Finally, the Owner did not believe the ISO had the authority to call units out of market, at least not without declaring a System Emergency.

Various RMR Owners have also asserted that Condition 2 RMR Units should not be subject to the must-offer obligation because the RMR Contract prohibits a Condition 2 RMR Unit from engaging in a Market Transaction when the ISO has not issued a Dispatch Notice for the unit.[41] However, the Commission has never expressly exempted Condition 2 Units from the must-offer obligation. Condition 2 RMR Units, however, are required to participate in the ISO's Ancillary Services and Imbalance Energy markets when operating to provide local reliability service unless specifically exempted.[42] This mandatory participation requirement was included in the RMR Contract to recognize that

[39] Even if the ISO could call units under the RMR Contract for system-wide needs, the costs would not be properly allocated, since RMR costs are allocated directly to a Participating TO, not to all Market Participants.

[40] Article 1 of the *pro forma* RMR Contract defines a "Market Transaction" as "a delivery of Energy or provision of Ancillary Services from a Unit pursuant to a Direct Contract or bids into markets run by the PX, ISO or any similar entity." This document is available from the ISO's web site at http://www.caiso.com/docs/2001/10/15/2001101510162513782.doc

[41] *See, e.g., pro forma* RMR Contract, Section 3.1 (ii).

[42] Currently, the only exception is the Hunters Point generating facility, which, pursuant to an agreement between PG&E and the City of San Francisco, is prohibited from operating except to ensure reliability.

while Condition 2 RMR Units may not be able to recover enough of their fixed costs through voluntary market participation (and therefore must elect Condition 2, which provides for full fixed cost recovery but prohibits voluntary participation in the market), the unit may be perfectly capable of operating in merit order under some circumstances and should do so where possible. The Participating TO for whose system the RMR Unit was designated pays the full fixed costs of the Condition 2 RMR Unit. Any profits realized from a Condition 2 RMR Unit participating in the ISO markets are returned to the Participating TO until the unit's fixed costs are completely recovered.

As set forth in Section 5.6.1 of the ISO Tariff, the ISO has the authority to call on any unit owned or controlled by a Participating Generator in circumstances in which the ISO considers that a system emergency is imminent or threatened. Participating Generators are bound to comply with this provision as they are with any provision of the ISO Tariff. This Tariff requirement stands irrespective of any limitation of the RMR Contract, and RMR contract holders also have executed Participating Generator Agreements with the ISO. Suppliers may argue that because the RMR Contract stands on equal footing with the Tariff, its limitations therefore preclude the ISO from taking service from a Condition 2 RMR Unit outside of the RMR Contract. That conclusion is false. RMR Contract limitations apply to service taken under the RMR Contract, not to any service that may be required outside of the RMR Contract. Any argument to the contrary would eviscerate the Participating Generator Agreements that unit owners have signed. While the RMR Contract limits the kind of service the ISO can take under that contract, it cannot limit the kind of service the ISO can take pursuant to other authority the ISO has through its Tariff via executed Participating Generator Agreements.

Section 14.10 of the *pro forma* RMR Contract sets forth:

> The ISO Tariff shall govern matters relating to the subject matter of this Agreement which are not set forth in this Agreement. In all other circumstances, this Agreement shall govern. In the event of a conflict between the terms and conditions of this Agreement and any terms and conditions set forth in the ISO Tariff the terms and conditions of this Agreement shall prevail.

The RMR Contract sets forth the ISO's limitations on dispatching an RMR Unit under the RMR Contract, but not in general. The ISO's right to dispatch units under the RMR Contract is reasonably limited to providing Ancillary Services when the market is insufficient and providing for local reliability. This was done to prevent the ISO from requiring service at cost-based rates when a competitive market would allow for market-based rates. Dispatching under the RMR Contract when a competitive market is available is a violation of the RMR Contract. It is not a conflict, however, to dispatch an RMR Unit under the provisions of the Tariff. Again, interpreting Section 14.10 to limit the ISO's right to call a Condition 2 RMR Unit under the Tariff – which that unit is bound to abide by as a condition of its Participating Generator Agreement – amounts to sanctioned withholding.

If RMR Owners prevail in their assertion that Condition 2 RMR Units should not be operated except for local reliability reasons under the terms of the RMR Contract, they ironically will have succeeded in exercising system-wide market power through the very contract that was intended to prevent the exercise of local market power. They will have effectively succeeded in withholding their unit from the broad market. At the same time, they will earn full fixed cost recovery, courtesy of a Responsible Utility, assuming they make their unit available for local reliability service under the terms of their RMR Contracts. Stated another way, any Responsible Utility paying for a Condition 2 RMR Unit will be paying the full fixed costs of a unit that can only be used to meet its local reliability needs but for no other reason. Such a restriction is not equitable for a unit that has both its fixed and variable operating costs covered.

Local reliability requirements aside, if an RMR Owner and a Responsible Utility had entered into a bilateral full cost-of-service contract in which the Responsible Utility was paying the unit's full fixed costs, it is reasonable to expect that the Responsible Utility would be able to call upon that unit to operate for any reason it saw fit. It should be able to run the unit for any purpose, not just to meet local reliability needs. The fact that the RMR Contract is between the ISO and the RMR Owner should not limit the use of the unit to only providing local reliability service.

There ***is*** a reason to restrict the Owner of a Condition 2 RMR Unit from voluntarily operating that unit in the market. Such a restriction is a reasonable *quid pro quo* for having the unit's fixed costs fully paid for and for voluntarily avoiding any market risk. There is no justifiable reason, however, to restrict the use of Condition 2 RMR Units to local reliability service.

At the September 3, 2003 technical conference, the ISO proposed a way to make Condition 2 RMR Units available for service outside the RMR Contract by subjecting them to the must-offer obligation and requiring that they bid into the ISO's markets at rates specified in Schedule M to the RMR Contract. Upon further examination, the ISO finds such a proposal is unworkable due to two provisions in the RMR Contract:

(1) The provisions that mandate that a Condition 2 RMR Unit cannot participate in a Market Transaction (by definition, one entered into pursuant to a bid or a direct contract) unless the unit has already been dispatched by the ISO under the RMR Contract to meet a local reliability need. This language

would prevent a unit from bidding into the ISO markets unless the unit is already operating under the RMR Contract. The problem that the ISO needs to address is where a Condition 2 RMR Unit is not already providing service under the RMR Contract. *See pro forma* RMR Contract, Sections 3.1 (ii) and 6.1 (b).

(2) The provision that a unit owner must credit all revenues from Market Transactions for a Condition 2 RMR Unit to the Responsible Utility. *See pro forma* RMR Contract, Sections 3.1 (ii) and 9.1 (f).

Under the terms of the RMR Contract, a Condition 2 RMR Unit can participate in an out-of-market transaction because such a transaction is not entered into pursuant to a bid in the ISO's markets. Without amending the RMR Contract, the only way to provide for the use of Condition 2 RMR Units outside the RMR Contract is to specify an out-of-market rate for such units.

The ISO proposes the following proposal for using Condition 2 RMR Units outside of the RMR Contract (i.e., for non-RMR service):

1. The ISO will use reasonable efforts to use all available and effective non-Condition 2 RMR Units before using Condition 2 RMR Units.

   In comments submitted on a draft of the instant filing, Williams strongly opposed use of Condition 2 units for non-RMR service, in part on a representation that the ISO would use the units for "whatever system needs [the ISO] desires to serve." Contrary to Williams' objections, the ISO has no intent to use Condition 2 units without condition on their use. The ISO has proposed to limit its use of Condition 2 units until after it has reasonably exhausted all other viable and effective options. In contrast, some parties in the must-offer stakeholder process offered that the ISO should use cost-of-service Condition 2 units for general system needs on a merit order basis. The ISO is seeking a tenable middle ground – to be able to use Condition 2 units where there are no other reasonable options, but not to use them without any other regard.

2. The ISO will not have to declare an emergency to use Condition 2 RMR Units for non-RMR service.

3. When needed for non-RMR service, Condition 2 RMR Units will be called out of market.

4. The RMR Unit will receive payment at a specified rate (discussed below) but will not also be paid for Uninstructed Imbalance Energy.

5. The ISO shall track combined RMR and non-RMR service (start-ups, MWh and service hours) for Condition 2 RMR Units.

6. Non-RMR service shall count towards the determination of subsequent years' service limits.[43]

7. As long as the combined RMR and non-RMR service does not exceed the applicable RMR Contract service limit, the ISO will pay the variable cost rate specified in Equation 1a (for Units with input/output data in polynomial form) or Equation 1b (for Units with input/output data in exponential form) in Schedule C to the RMR Contract for non-RMR energy produced by the RMR Unit in response to an ISO dispatch instruction. As long as the combined RMR and non-RMR service does not exceed the applicable RMR Contract service limit, the ISO will pay for any non-RMR start-ups at the rate specified in Schedule D to the RMR Contract. These rates are the rates the ISO would normally pay for service below the Contract Service Limits taken under the RMR Contract.

8. When the combined RMR and non-RMR service exceeds the RMR Contract Service Limit, the ISO shall pay the Schedule G rate for all subsequent service, both RMR and non-RMR service, requested by the ISO.

9. If the combined RMR and non-RMR service exceeds the Contract Service Limits, but the total annual RMR Service does not exceed the Contract Service Limit, the Responsible Utility shall pay only the rate specified under the RMR Contract (set forth in Schedule C or D), but the ISO shall provide an additional payment (collected from the market as any out-of-market ("OOM") cost would be collected) so that the RMR Owner is paid the Schedule G rate. The Responsible Utility shall pay the Schedule G rate for RMR service when RMR service by itself exceeds the Contract Service Limits.

10. The cost of all non-RMR service and the additional cost of RMR Service above Schedule C or D when the combined RMR and non-RMR service has exceeded the RMR Contract Service Limits shall be allocated the way out-of-market costs are currently allocated, with all start-up costs considered to be above-MCP costs.

11. The ISO's calculation of Counted MWh, Counted Service Hours and Counted Start-ups, along with the ISO's tracking of non-RMR service,

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[43] Service limits are determined by a rolling five-year average of both RMR and market service. *See pro forma* RMR Contract, Section 4.11.

shall be used to determine when the unit's cumulative RMR and non-RMR service exceeds the Contract Service Limits.

OOM Energy costs for Condition 2 RMR Units shall be allocated as currently set forth in the ISO Tariff. The ISO proposes that RMR Owners invoice the ISO for Condition 2 RMR OOM Start-Up costs, including the additional payment due when the ISO calls on a Condition 2 RMR Unit for RMR service after a unit's service has exceeded its Contract Service Limit for total service but before RMR service exceeds the Contract Service Limit, consistent with the practice currently set forth in Section 2.5.23.3.7.6 of the ISO Tariff. The ISO advocates this approach for two reasons. First, the ISO expects that these Condition 2 RMR Unit Start-up costs will be small, and therefore it is reasonable to include them in the mechanism already established by the Commission to pay start-up costs. Second, having the Owners bill the ISO for these costs is more practical and equitable way to provide that the costs are properly paid than having the ISO merely calculate the proposed amounts and settle them with no input from the Owner. Start-up costs are allocated to all metered Demand within the ISO Control Area and to exports to Demand within California.

This proposed treatment is just and reasonable and recognizes that RMR Condition 2 Unit Owners have obligations under the ISO Tariff through the Participating Generator Agreements they have executed. It is fair to RMR Owners because it provides them with the same compensation they would be entitled to under the RMR Contract, both above and below the RMR Contract Service Limits. It is fair to Responsible Utilities because any additional cost incurred by non-RMR service is allocated to the market, not to the Responsible Utility. It places reasonable but not overly restrictive conditions on the ISO's ability to use these units for non-RMR service. It ends real-time debates between ISO and unit operating personnel about the ISO's authority to call on Condition 2 RMR Units outside of the RMR Contract. For all these reasons, the ISO urges the Commission to approve this proposed treatment.

In comments on a draft of the instant filing, SCE proposed that the ISO post information regarding non-RMR use of Condition 2 RMR Units on its web site. While the ISO cannot post unit-specific information, the ISO understands SCE's desire for this information and will explore how such information might be provided via OASIS without violating confidentiality or disclosing commercially sensitive information.

IV. EFFECT ON METERED SUBSYSTEMS

The changes proposed in the instant amendment should not conflict with the principles of the MSS Agreement ("MSSA"). Some of the instant proposals closely align with the principles in the MSSA. As an example, the proposed three-tiered allocation of minimum load costs reflects more precise cost-causation principles and is consistent with the MSSA. If MSS Operators or Aggregators believe that the provisions of the instant filing conflict with the MSSA, the ISO is willing to work with those entities to try to address their concerns.

V. PROPOSED TARIFF CHANGES

The ISO is proposing changes to the following Tariff Sections:

Section	Proposed Change	See Transmittal Letter Section
2.5.21	Included the possibility that Minimum Load Energy needed to provide Ancillary Services could be obtained under the must-offer obligation.	III.D.4 (b)
2.5.23.3.4	Changed the proxy figure for natural gas costs to be the figure used in RMR Contract Schedule C.	III.D.2; III.D.4 (a)
2.5.23.3.7 7.1, 7.2, 7.3, 7.4, 7.5, 7.7	Eliminated the word "fuel" to allow that auxiliary power can be included in the Start-Up Cost.	III.D.3
2.5.23.3.7.1	Set forth that the Start-Up Cost now includes both fuel and auxiliary power.	III.D.3
2.5.23.3.7.6	The ISO is contemplating that when a Condition 2 RMR Unit is called out-of-market, the ISO would pay the charges associated with that start-up through the start-up trust account established.	III.F
5.6.1	Includes language that expressly authorizes the ISO to call on a Condition 2 RMR Unit out-of-market without declaring a system emergency if the ISO has used all other available resources.	III.F
5.11.4	Added language to condition a Must-Offer Generator's requirement to offer to sell all Available Generation.	III.D
5.11.6	• Clarified that when a generating unit subject to the must-offer obligation submits Day-Ahead energy schedules, those schedules constitute self-commitment and render the unit ineligible to recover Minimum Load Costs in that hour even if the Day-Ahead schedules are subsequently nullified in the Hour-Ahead market. • Changed the timeline for submitting requests for Must-Offer Waivers from 6 PM to 10 AM;	III.C.2 III.C.3

Section	Proposed Change	See Transmittal Letter Section
	and changed the time for the ISO to act on the waiver requests from 8 PM to 11:30 AM. Note: the black-line of this section still contains revisions proposed in earlier filings.	
5.11.6.1.1	Eliminated the provision in which having a Final Hour-Ahead Ancillary Services schedule renders the unit ineligible to recover Minimum Load Costs in that hour.	III.D.4 (b)
5.11.6.1.2	Includes modifications from previous filings.	
5.11.6.1.2.1	Included new section to pay a Must-Offer Generator the greater of the market clearing price or the unit's costs for the amount of energy that must be produced to move a unit to a level from which it can quickly and effectively respond to real-time dispatch instructions.	III.D.4 (c)
5.11.6.1.4	Added language to provide three-part allocation of Minimum Load Costs and to clarify that Minimum Load Costs are allocated on a monthly basis.	III.E
5.11.6.2	Added this section to set forth the criteria for granting waivers of the must-offer obligation.	III.C.1
11.2.4.2	Added language to provide compensation for Condition 2 RMR Units called out-of-market by the ISO.	III.D
11.2.4.2.1.1	Added language to allocate the costs of Condition 2 RMR Units called out-of-market by the ISO.	III.D
Reliability Services Costs	Added this definition.	III.E
Start-Up Fuel Cost Charge	Struck the word "fuel".	III.D.3
Start-Up Fuel Demand	Struck the word "fuel".	III.D.3
Start-Up Fuel Cost Invoice	Struck the word "fuel".	III.D.3
Start-Up Fuel Cost Trust Amount	Struck the word "fuel".	III.D.3

Section	Proposed Change	See Transmittal Letter Section
Start-Up Fuel Costs	• Struck the word "fuel"; • Modified the language so that costs could include both fuel and auxiliary power.	III.D.3

The ISO is including two sets of Tariff modifications – one to be effective prior to the implementation of the MD02 Phase 1B changes approved in Amendment No. 54, and a second to be effective after the implementation of the MD02 Phase 1B changes approved in Amendment No. 54.

VI. EFFECTIVE DATE

The ISO respectfully requests that the provisions of this Amendment, with the exception of (1) the cost allocation provisions contained in Tariff Section 5.11.6.1.4, and (2) the provisions regarding the use of a unit commitment application contained in Section 5.11.6.2 be made effective 60 days after the date filing, on July 11, 2004. Because the implementation of the unit commitment application depends on integrating a new application with existing applications, the ISO respectfully requests that it be permitted to put the relevant changes in 5.11.6.2 ten (10) days after notice by the ISO. The ISO's Settlements department is currently engaged in several major projects, including conducting preparatory re-runs for the refund proceeding in Docket Nos. EL00-95 and EL00-98, replacing the aging existing settlements system, and deploying the Phase 1B modifications. At this time, the ISO believes that it would be both efficient and prudent to incorporate the development work needed to modify the system changes needed to implement the cost allocation provisions of Tariff Section 5.11.6.1.4 into the work needed to deploy the Phase 1B modifications and to deploy those modifications at the same time the Phase 1B modifications are deployed. The ISO has not yet determined the date when the Phase 1B modifications will be deployed. The ISO respectfully requests that, consistent with the effective date requested for the Phase 1B modifications in Amendment No. 54, that the ISO put the Tariff modifications needed to implement the revised cost allocation into effect ten days after notice to the market and to the Commission that the Phase 1B software is ready to be deployed. To avoid mid-month settlement implications, the implementation date will be on the first day of a month.

In comments submitted on a draft of the instant filing, PG&E urged the ISO to revise the cost allocation prior to the implementation of the Phase 1B modifications. The ISO acknowledges Page's concerns about inequity of the current cost allocation, but does not believe it is prudent to revise the current settlements system for just a few months until the Phase 1B modification are ready to be implemented. To do so could delay the Phase 1B modifications or disrupt the current preparatory re-run process.

VII. COMMUNICATIONS

Communications regarding this filing should be addressed to the following individuals, whose names should be placed on the official service list established by the Secretary with respect to this submittal:

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VIII. SERVICE

The ISO has served copies of this letter, and all attachments, on the California Public Utilities Commission, the California Energy Commission, the California Electricity Oversight Board, on all parties with effective Scheduling Coordinator Service Agreements under the ISO Tariff, and on all parties on the official service list for Docket Nos. EL00-95 and EL00-98. In addition, the ISO is posting this transmittal letter and all attachments on the ISO Home Page.

IX. ATTACHMENTS

The following documents, in addition to this letter, support this filing:

Attachment A1	Revised Tariff sheets – pre-Amendment No. 54[44]
Attachment A2	Revised Tariff sheets – post-Amendment No. 54
Attachment B1	Black-lined Tariff provisions – pre-Amendment No. 54
Attachment B2	Black-lined Tariff provisions – post-Amendment No. 54

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44 As Amendment No. 54 was accepted by the Commission but not yet made effective, the ISO is providing clean sheets and black-lines to illustrate how Amendment No. 60 would affect the ISO Tariff as currently in effect and how it will work with Amendment No. 54 when implemented in the future.

Attachment C	Stakeholder position matrix
Attachment D	Analysis of monthly and daily gas costs
Attachment E	Cost allocation white paper
Attachment F	Notice of this filing, suitable for publication in the Federal Register (also provided in electronic format)

Two extra copies of this filing are also enclosed. Please stamp these copies with the date and time filed and return them to the messenger. Please feel free to contact the undersigned if you have any questions concerning this matter.

Respectfully submitted,

Anthony J. Ivancovich BRM

Charles F. Robinson
Anthony J. Ivancovich

Counsel for The California Independent System Operator Corporation

Enclosures

ATTACHMENT A1

notify each Scheduling Coordinator no later than 1:00 p.m. of the day prior to the Trading Day of their Ancillary Services schedules for the Day-Ahead and no later than one hour prior to the operating hour of their Ancillary Services schedules for the Hour-Ahead. The ISO Protocols set forth the information, which will be included in these schedules. Where long-term contracts are involved, the information may be treated as standing information for the duration of the contract.

If, at any time after the issuance of Final Day-Ahead Schedules for the Trading Day and before the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day, the ISO determines that it requires Ancillary Services in addition to those included in the Final Day-Ahead Schedule (in the appropriate Zone if procuring zonally), the ISO may procure such additional Ancillary Services by providing Scheduling Coordinators with amended supplier schedules for the Day-Ahead Markets that include Ancillary Services for which previously submitted (but not selected) bids remain available and have not previously been withdrawn. The ISO shall select such Ancillary Services in price merit order (and in the relevant Zone if the ISO is procuring Ancillary Services on a Zonal basis). Such amended supplier schedules shall be provided to the Scheduling Coordinators no later than the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day.

Once the ISO has given Scheduling Coordinators notice of the Day-Ahead and Hour-Ahead Schedules, these schedules represent binding commitments made in the markets between the ISO and the Scheduling Coordinators concerned, subject to any amendments issued as described above. Any minimum energy input and output associated with Regulation and Spinning Reserve services shall be the responsibility of the Scheduling Coordinator, or provided in accordance with the must-offer obligation as set forth in Section 5.11, as the ISO's auction does not compensate the Scheduling Coordinator for the minimum energy output of Generating Units bidding to provide these

services. Accordingly, except as set forth under Section 5.11, the Scheduling Coordinators shall adjust their schedules to accommodate the minimum outputs required by the Generating Units to facilitate delivery of Energy from Ancillary Services.

Notwithstanding the foregoing, a Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace that capacity in whole or in part from the ISO if the scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or if the Ancillary Service associated with a Generating Unit, Curtailable Demand, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduling Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replaced Ancillary Service shall be the Market Clearing Price in the Hour-Ahead Market for the Ancillary Service for the Settlement Period concerned for the Zone in which the Generating Units or other resources are located. The ISO will purchase the Ancillary Service concerned from another Scheduling Coordinator in the Hour-Ahead Market in accordance with the provisions of the ISO Tariff.

2.5.22 Rules For Real-Time Dispatch of Imbalance Energy Resources.

2.5.22.1 Overview. During real time, the ISO shall dispatch Generating Units, Loads and System Resources to procure Imbalance Energy. In addition, the ISO may also need to purchase additional Ancillary Services if the services arranged in advance are used to provide Imbalance Energy, and such depletion needs to be recovered to meet reliability contingency requirements.

the ISO will assess the Emissions Cost Charge in accordance with Section 2.5.23.3.6.4. Any outstanding Emissions Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay Emissions Costs is limited to the obligation to pay Emissions Cost Charges received. All disputes concerning payment of Emissions Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.

2.5.23.3.7 Start-Up Fuel Costs

2.5.23.3.7.1 Obligation to Pay Start-Up Fuel Cost Charges

Each Scheduling Coordinator shall be obligated to pay a charge which will be used to pay the verified Start-Up Fuel Costs incurred by a Must-Offer Generator as a direct result of an ISO Dispatch instruction, in accordance with this Section 2.5.23.3.7. Such Start-Up Costs shall include (1) fuel and (2) auxiliary power. The ISO shall levy this charge (the "Start-Up Cost Charge"), each month, against all Scheduling Coordinators based upon each Scheduling Coordinator's Control Area Gross Load and Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area. Scheduling Coordinators shall make payment for all Start-Up Cost Charges in accordance with the ISO Payments Calendar.

2.5.23.3.7.2 Start-Up Cost Trust Account

All Start-Up Cost Charges received by the ISO shall be deposited in the Start-Up Cost Trust Account. The Start-Up Cost Trust Account shall be an interest-bearing account separate from all other accounts maintained by the ISO, and no other funds shall be commingled in it at any time.

2.5.23.3.7.3 Rate For the Start-Up Cost Charge

The rate at which the ISO will assess the Start-Up Cost Charge shall be at the projected annual total of all Start-Up Costs incurred by Must-Offer Generators as a direct result of

ISO Dispatch instruction, adjusted for interest projected to be earned on the monies in the Start-Up Cost Trust Account, divided by the sum of the Control Area Gross Load and the projected Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area ("Start-Up Cost Demand"). The initial rate for the Start-Up Cost Charge, and all subsequent rates for the Start-Up Cost Charge, shall be posted on the ISO Home Page.

2.5.23.3.7.4 Adjustment of the Rate For the Start-Up Cost Charge

The ISO may adjust the rate at which the ISO will assess the Start-Up Cost Charge on a monthly basis, as necessary, to reflect the net effect of the following:

(a) the difference, if any, between actual Start-Up Cost Demand and projected Start-Up Cost Demand;

(b) the difference, if any, between the projections of the Start-Up Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instructions and the actual Start-Up Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instructions as invoiced to the ISO and verified in accordance with this Section 2.5.23.3.7; and

(c) the difference, if any, between actual and projected interest earned on funds in the Start-Up Cost Trust Account.

The adjusted rate at which the ISO will assess the Start-Up Cost Charge shall take effect on a prospective basis on the first day of the next calendar month. The ISO shall publish all data and calculations used by the ISO as a basis for such an adjustment on the ISO Home Page at least five (5) days in advance of the date on which the new rate shall go into effect.

2.5.23.3.7.5 Credits and Debits of Start-Up Cost Charges Collected from Scheduling Coordinators

In addition to the surcharges or credits permitted under Section 11.6.3.3 of this ISO Tariff, the

ISO may credit or debit, as appropriate, the account of a Scheduling Coordinator for any over- or under-assessment of Start-Up Cost Charges that the ISO determines occurred due to the error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

2.5.23.3.7.6 Submission of Start-Up Cost Invoices

Scheduling Coordinators for Must-Offer Generators that incur Start-Up Costs as a direct result of an ISO Dispatch instruction or if the ISO revokes a waiver from compliance with the must-offer obligation while the unit is off-line in accordance with Section 5.11.6 of this ISO Tariff, and Scheduling Coordinators for Generation Units operating under Condition 2 of the relevant RMR Contract which are called out-of-market in accordance with Section 11.2.4.2 of this ISO Tariff or who are due an additional payment for a start-up under the RMR Contract in accordance with Section 11.2.4.2 of this ISO Tariff may submit to the ISO an invoice in the form specified on the ISO Home Page (the "Start-Up Cost Invoice") for the recovery of such Start-Up Costs. Such Start-Up Costs shall not exceed the costs which would be incurred within the start-up time for a unit specified in Schedule 1 of the Participating Generator Agreement. Start-Up Cost Invoices shall use the applicable proxy figure for natural gas costs as determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas. Start-Up Cost Invoices shall specify the amount of auxiliary power used during the start-up and the actual price paid for that power. Start-Up Cost Invoices shall not include any Start-Up Costs specified in an RMR Contract for a unit owned or controlled by a Must-Offer Generator.

2.5.23.3.7.7 Payment of Start-Up Cost Invoices

The ISO shall pay Scheduling Coordinators for all Start-Up Costs submitted in a Start-Up Cost Invoice and demonstrated to be a direct result of an ISO Dispatch instruction. The ISO shall pay such Start-Up Cost Invoices each month in accordance with the ISO Payments Calendar from the funds available in the Start-Up Cost Trust Account. To the extent there are insufficient funds available in the Start-Up Cost Trust Account in any month to pay all Start-Up Costs submitted in a Start-Up Cost Invoice and demonstrated to be a direct result of an ISO Dispatch instruction, the ISO shall make pro rata payment of such Start-Up Costs and shall adjust the rate at which the ISO will assess the Start-Up Cost Charge in accordance with Section 2.5.23.3.7.4. Any outstanding Start-Up Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay Start-Up Costs is limited to the obligation to pay Start-Up Cost Charges received. All disputes concerning payment of Start-Up Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.

2.5.23.3.8 [Not Used]

2.5.23.3.8.1 Hydro-Electric Resources within the ISO Control Area.

Hydro-electric resources within the ISO Control Area are not required to submit $0/MWh or other price-taker bids and are eligible to set a market clearing price.

under this ISO Tariff) subject to control by the ISO during a System Emergency and in circumstances in which the ISO considers that a System Emergency is imminent or threatened. The ISO shall, subject to Section 5.6.2, have the authority to instruct a Participating Generator to bring its Generating Unit on-line, off-line, or increase or curtail the output of the Generating Unit and to alter scheduled deliveries of Energy and Ancillary Services into or out of the ISO Controlled Grid, if such an instruction is reasonably necessary to prevent an imminent or threatened System Emergency or to retain Operational Control over the ISO Controlled Grid during an actual System Emergency. The ISO shall have the authority to instruct an RMR Unit whose owner has selected Condition 2 of its RMR Contract to start-up and change its output if the ISO has reasonably used all other available and effective resources to prevent a threatened System Emergency without declaring that a System Emergency exists. It the ISO so instructs a Condition 2 RMR Unit, it shall compensate that unit in accordance with Section 11.2.4.2 and allocate the costs in accordance with Section 11.2.4.2.1.1.

5.6.2 The ISO shall, where reasonably practicable, utilize Ancillary Services which it has the contractual right to instruct and which are capable of contributing to containing or correcting the actual, imminent or threatened System Emergency prior to issuing instructions to a Participating Generator under Section 5.6.1.

5.6.3 [Not Used]

each non-hydroelectric Generating Unit located in California they own or control: (i) the Unit's minimum operating level; (ii) the Unit's maximum operating level; and (iii) the Unit's ramp rates at all operating levels; and (iv) such other information the ISO determines is necessary to determine available generation and to dispatch Must-Offer Generators. In addition, Must-Offer Generators that are not Participating Generators must, consistent with the notification obligations of Participating Generators and in order to comply with the intent of this Section 5.11, notify the ISO, as soon as practicable, of any Planned Maintenance Outages, Forced Outages, Force Majeure Event outages or any other reductions in their maximum operating levels.

5.11.4 Obligation To Offer Available Capacity

Except as set forth in Section 5.11.6, all Must-Offer Generators shall offer to sell in the ISO's Real Time Market for Imbalance Energy, in all hours, all their Available Generation as defined in Section 5.11.2.

5.11.5 Submission of Bids and Applicability of the Proxy Price

For each Operating Hour, Must-Offer Generators shall submit Supplemental Energy bids for all of their Available Generation to the ISO in accordance with Section 2.5.22.4. In addition, the ISO shall calculate for each gas-fired Must-Offer Generator, in accordance with Section 2.5.23, a Proxy Price for Energy.

If a Must-Offer Generator fails to submit a Supplemental Energy bid for any portion of its Available Generation for any BEEP Interval, the unbid quantity of the Must-Offer Generator's Available Generation will be deemed by the ISO to be bid at the Must-Offer Generator's Proxy Price for that hour if: (i) the applicable Generating Unit is a gas-fired unit and (ii) the Must-Offer Generator has provided the ISO with adequate data in compliance with Sections 2.5.23.3.3 and 5.11.3 for the applicable Generating Unit. For all other Generating Units owned or controlled by a Must-Offer Generator, the unbid quantity of the Must-Offer Generator's Available Generation will be deemed by the ISO to be bid to receive the BEEP Interval Ex Post Price. In order to dispatch resources providing Imbalance Energy in proper merit order, the ISO will insert this unbid quantity into the Must-Offer Generator's Supplemental Energy bid curve above any lower-priced segments of the bid curve and below any higher-priced segments of the bid curve as necessary to maintain a non-decreasing bid curve over the entire range of the Must-Offer Generator's Available Generation.

5.11.6 Must-Offer Obligation Process

Must-Offer Generators may seek a waiver of the obligation to offer all available capacity, as set forth in Section 5.11.4 of this ISO Tariff, for one or more of their Generating Units for periods other than Self-Commitment Periods. Self-Commitment Periods are defined as the hours for which Must-Offer Generators submit Day-Ahead Energy Schedules. Self-Commitment Periods determined from Day-Ahead Schedules shall be extended by the ISO as necessary to accommodate Generating Unit minimum up and down times such that the scheduled operation is feasible.

All other Must-Offer Generators obligated under the must-offer obligation that have not submitted Day-Ahead Energy Schedules will be deemed to have requested a waiver, either implicitly or explicitly, of the obligation to offer all available capacity. If conditions permit, and at the ISO's non-discriminatory and sole discretion, the ISO may grant waivers and allow a Must-Offer Generator to remove one or more Generating Units from service. The Self-Commitment Period defined by a Generating Unit's Day-Ahead schedules (plus any additional time necessary to accommodate minimum up and minimum down times) shall remain in effect for that Generating Unit even if a Must-Offer Generator nullifies the Day-Ahead Schedules submitted for that unit in the Hour-Ahead Market. If a Must-Offer Generator requests a waiver for a Generating Unit for its Self-Commitment Period, the ISO may grant the waiver, but if the ISO denies the waiver, the unit shall not be eligible to recover Minimum Load Costs incurred during any Self-Commitment Period as set forth in Section 5.11.6.1.1.

The hours outside of Self-Commitment Periods for which waivers are not granted shall constitute Waiver Denial Periods. A Waiver Denial Period shall be extended as necessary to accommodate Generating Unit minimum up and down times. Units shall be on-line in real time during both Self-Commitment and Waiver Denial Periods, or they will be in violation of the must-offer obligation. Exceptions shall be allowed for verified forced outages. The ISO may revoke waivers as necessary due to outages, changes in Load forecasts, or changes in system conditions. The ISO shall determine which waiver(s) will be revoked, and shall notify the relevant Scheduling Coordinator(s). The ISO shall inform a Must-Offer Generator that its Waiver request has been accepted, denied, or revoked, and shall provide the Must-Offer Generator with the reason(s) for the decision, which reasons shall be non-discriminatory. The ISO will: (1) notify Must-Offer Generators of the ISO decisions on pending Waiver requests received no later than 10:00 a.m. (beginning of Hour Ending 11) no later than 11:30 a.m. (middle of Hour Ending 12) on the day before the operating day for which the Waivers are requested; (2) at any time but no later than 11:30 a.m. on the following day, notify Must-Offer Generators of the ISO decisions on Waiver requests that were submitted to the ISO after 10:00 a.m. (beginning of Hour Ending 11) on the day before; (3) end Waiver Denial Periods at any time; and (4) revoke Waivers at any time, while making best attempts to revoke a Waiver at least 90 minutes prior to time a unit would be required to be on-line generating at its Pmin.

5.11.6.1 Recovery of Minimum Load Costs By Must-Offer Generators

5.11.6.1.1 Eligibility

Units from Must-Offer Generators that incur Minimum Load Costs during Self-Commitment Periods or during hours for which the ISO has granted to them a waiver shall not be eligible to recover such costs for such hours. When a Must-Offer Generator has a Final Hour-Ahead Energy Schedule other than a Schedule to a unit-specific Demand ID used for the purpose of scheduling minimum load energy as set forth in Section 5.11.6, the Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on an hourly basis, a Must-Offer Generator generating at minimum load in compliance with the must-offer obligation, produces a quantity of Energy that varies by more than the greater of: (i) five (5) MWh or (ii) an hourly Energy amount equal to three (3) percent (%) of the unit's maximum operating output, the Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. Subject to the foregoing eligibility restrictions set forth in this section, the ISO shall pay to an otherwise eligible Must-Offer Generator the Minimum Load Costs for each hour within a Waiver Denial Period that the Generating Unit runs at minimum load in compliance with the must-offer obligation and for each hour that an otherwise eligible Must-Offer Generator generates in compliance with an ISO Dispatch Instruction.

5.11.6.1.2 Minimum Load Costs

The Minimum Load Costs shall be calculated as the sum, for all eligible hours in the Waiver Denial Period and Settlement Periods in which the unit generated in response to an ISO Dispatch Instruction, of: 1) the product of the unit's average heat rate (as determined by the ISO from the data provided in accordance with Section 2.5.23.3.3) at the unit's minimum operating level as set forth in Schedule 1 of the Generating Unit's Participating Generator Agreement and the gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas; and 2) the product of the unit's minimum operating level as set forth in Schedule 1 of the Generating Unit's Participating Generator Agreement and $6.00/MWh.

5.11.6.1.2.1 Operating Must-Offer Generating Units above Minimum Load

If, during a Waiver Denial Period, the ISO requires that a Generating Unit operate at a level above its minimum load operating so as to be able to respond effectively to real time Dispatch Instructions, the ISO shall operate that Generating Unit at such an operating level. The ISO shall pay the Minimum Load Costs set forth in Section 5.11.6.1.2 for the amount of the Generating Unit's Minimum Load. For the amount of Energy above Minimum Load to the Unit's required operating level, the ISO shall pay the greater of the product of such amount of Energy and (1) the price for instructed Imbalance Energy or (2) the sum of (a) the product of (i) the Generating Unit's incremental heat rate at the required operating level and (ii) the proxy figure for natural gas costs set forth in Section 2.5.23.4 and (b) $6.00

5.11.6.1.3 Invoicing Minimum Load Costs

The ISO shall determine each Scheduling Coordinator's Minimum Load Costs and make payments for these costs as part of the ISO's market settlement process. Scheduling Coordinators may 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 defined in Section 5.11.6.1.1, that the unit generated above minimum load in compliance with ISO Dispatch Instructions.

5.11.6.2 Criteria for Issuing Must-Offer Waivers

The ISO shall grant waivers so as to: 1) provide sufficient on-line generating capacity to meet operating reserve requirements; and 2) account for other physical operating constraints, including Generating Unit minimum up and down times. The ISO shall grant, deny or revoke waivers using a security-constrained unit commitment software application to minimize start-up and Minimum Load Costs.

Scheduling Coordinator for each Settlement Period for each such resource by application of either of the following payment options described below. For resources subject to a Reliability Must-Run Contract, the ISO will dispatch such resources according to the terms of the RMR Contract, except as provided for below. In circumstances where an RMR Unit would be used to resolve Intra-Zonal Congestion and there are no such RMR Units available, a resource may be called upon and paid under this Section to resolve the Intra-Zonal Congestion.

By December 31 of each year for the following calendar year, each Scheduling Coordinator for a resource shall select one of the following payment options for each resource it schedules:

(a) the Uninstructed Imbalance Energy charge price as calculated in accordance with Section 2.5.23.2.2 (i.e., using the Hourly Ex Post Price) or

(b) a calculated price:

(i) for decremental dispatch orders that is an Energy payment to the ISO that is equal to the Market Clearing Price for the relevant Settlement Period for the applicable Energy market less verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's Dispatch Instruction and that the Scheduling Coordinator or Generator was not able to eliminate or reduce despite the application of best efforts, if the Scheduling Coordinator provides the resource's daily gas imbalance charges to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched; and

(ii) for incremental dispatch orders is the sum of: 1) a capacity payment equal to the average Day-Ahead Market prices for Spinning Reserve and Non-Spinning Reserve for the three (3) most recent similar days for the same Settlement Period for which the resource is dispatched; 2) an Energy payment equal to the average calculated using the ISO Real Time Market Energy prices for the three (3) most recent similar days for the same Settlement Period for which the resource is dispatched; 3) such resource's verifiable Start-Up Costs, if the start-up was solely attributable to the ISO's Dispatch Instruction and if the Scheduling Coordinator provides the resource's Start-Up Costs to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched; and 4) verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's Dispatch Instruction and that the Scheduling Coordinator or Generator was not able to eliminate or reduce despite the application of best efforts, if the Scheduling Coordinator provides the resource's daily gas imbalance charges to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched. References to "similar days" in this Section refer to Business Days when the resource is dispatched on a Business Day and otherwise to days that are not Business Days.

To the extent a Scheduling Coordinator does not specify a payment option, the ISO will apply the payment provisions of the payment option described in Section 11.2.4.2(a).

If the ISO Dispatches an RMR Unit that has selected Condition 2 of its RMR Contract to start-up or provide energy other than a start-up or energy requested pursuant to the RMR Contract, the ISO shall pay as follows:

1) if, as determined by the ISO, the sum of the service hours, service MWh or start-ups

from service not under the RMR Contract and RMR Contract Counted Service Hours, Counted MWh, or Counted Start-ups does not exceed the applicable RMR Contract Service Limit, the ISO shall pay (a) for energy, the rate set forth in either Equation 1a or 1b below, as appropriate and (b) for a start-up, the rate specified in Schedule D to the applicable RMR Contract.

2) Equation 1a (for Units with input/output data in polynomial form) or Equation 1b (for Units with input/output data in exponential form) as defined below shall be used to calculate the Energy rate for MWh of Instructed Imbalance Energy delivered:

Equation 1a

$$\text{Energy Price (\$/MWh)} = \frac{(AX^3 + BX^2 + CX + D) * P * E}{X} + \text{Variable O\&M Rate}$$

Equation 1b

$$\text{Energy Price (\$/MWh)} = \frac{A * (B + \text{Cm } X + De^{FX}) * P * E}{X} + \text{Variable O\&M Rate}$$

Where:

- for Equation 1a, A, B, C, D and E are the coefficients given in Table C1-7a of the applicable RMR Contract;
- for Equation 1b, A, B, C, D, E and F are the coefficients given in Table C1-7b of the applicable RMR Contract;
- X is the Unit output level during the applicable settlement period, MWh;
- P is the Hourly Fuel Price as calculated by Equation C1-8 in Schedule C using the Commodity Prices in accordance with the applicable RMR Contract;
- Variable O&M Rate ($/MWh): as shown on Table C1-18 of the applicable RMR Contract.

3) If, as determined by the ISO, the sum of the service hours, service MWh or start-ups from service instructed by the ISO not under the RMR Contract and RMR Contract Counted Service Hours, Counted MWh, or Counted Start-ups, as applicable, exceeds the applicable RMR Contract Service Limit, the ISO shall pay:

a) if the Owner has elected Option A of Schedule G, two times the start-up cost specified in Schedule D to the applicable RMR Contract for any start-up incurred, and 1.5 times the rate specified in Equation 1a or 1b above times the amount of energy delivered in response to the ISO's instruction;

(b) if the Owner has elected Option B of Schedule G, three times the start-up cost specified in Schedule D to the applicable RMR Contract for any start-up incurred, and the rate specified in Equation 1a or 1b above times the amount of energy delivered in response to the ISO's instruction.

If the ISO Dispatches an RMR Unit pursuant to under the RMR Contract when the sum of the service hours, service MWh or start-ups from service not under the RMR Contract and the RMR Contract Counted Service Hours, Counted MWh or Counted Start-ups, as applicable, has exceeded the applicable RMR Contract Service Limit, the ISO shall pay the Scheduling Coordinator an additional amount so that the Scheduling Coordinator receives, in total, from the payment provided pursuant to the RMR Contract and the additional amount, the rates specified in Schedule G to the RMR Contract for the RMR Energy provided or for the RMR Start-Up Costs incurred until either the RMR Contract Counted MWh, Counted Service Hours or Counted Start-ups exceed the relevant RMR Contract Service Limit.

11.2.4.2.1 Allocation of Costs Resulting From Dispatch Instructions

Pursuant to Section 11.2.4.1, the ISO may, at its discretion, Dispatch any Participating Generator, Participating Load and dispatchable Interconnection resource that has not bid into the Imbalance Energy or

Ancillary Services markets, to avoid an intervention in market operations or to prevent or relieve a System Emergency. Such Dispatch may result from, among other things, planned and unplanned transmission facility Outages; bid insufficiency in the Ancillary Services and real-time Energy markets; and location-specific requirements of the ISO. The cost associated with each Dispatch instruction is broken into two components:

a) the portion of the Energy payment at or below the Market Clearing Price ("MCP") for the BEEP Interval, and

b) the portion of the Energy payment above the MCP, if any, for the BEEP Interval.

For each BEEP Interval, costs above the MCP incurred by the ISO for such Dispatch instructions necessary as a result of a transmission facility Outage or in order to satisfy a location-specific requirement in that BEEP Interval shall be payable to the ISO by the Participating Transmission Owner in whose PTO Service Territory the transmission facility is located or the location-specific requirement arose. The costs incurred by the ISO for such Dispatch instructions for reasons other than for a transmission facility Outage or a location-specific requirement will be recovered in the same way as for Instructed Imbalance Energy.

11.2.4.2.1.1 Allocation of Costs from Out-Of-Market calls to Condition 2 RMR Units

All costs associated with energy provided by a Condition 2 RMR unit operating other than according to a dispatch notice issued under the RMR Contract shall be allocated in accordance with Section 11.2.4.2.1. Until either the RMR Contract Counted MWh, Counted Service Hours or Counted Start-ups exceed the relevant RMR Contract Service Limit, any cost incurred for energy provided under the RMR Contract above the rate specified in equation 1a or 1b as set forth in Section 11.2.4.2 shall be allocated in accordance with Section 11.2.4.2.1, not to the Responsible Utility.

Start-Up Costs for Condition 2 RMR Units providing service outside the RMR Contract, and any additional Start-Up Cost associated with a Condition 2 RMR Unit providing service under the RMR Contract when the unit's total service has exceeded an RMR Contract Service Limit but neither the RMR Contract Counted MWH, Counted Hours or Counted Start-ups have exceeded the applicable RMR Contract Service Limit, shall be invoiced in accordance with Section 2.5.23.3.7.6 and collected in accordance with Section 2.5.23.3.7.1.

11.2.4.2.2 Allocation of Above-MCP Costs

For each BEEP Interval, the above-MCP costs incurred by the ISO as a result of Instructed Imbalance Energy and Dispatch instructions for reasons other than for a transmission facility Outage or a location-specific requirement shall be charged to Scheduling Coordinators as follows. Each Scheduling Coordinator's charge shall be the lesser of:

(a) the pro rata share of the total above-MCP costs based upon the ratio of each Scheduling Coordinator's Net Negative Uninstructed Deviations to the total system Net Negative Uninstructed Deviations; or

Reliability Must-Run Contract (RMR Contract)	A Must-Run Service Agreement between the owner of an RMR Unit and the ISO.
Reliability Must-Run Generation (RMR Generation)	Generation that the ISO determines is required to be on line to meet Applicable Reliability Criteria requirements. This includes i) Generation constrained on line to meet NERC and WECC reliability criteria for interconnected systems operation; ii) Generation needed to meet Load demand in constrained areas; and iii) Generation needed to be operated to provide voltage or security support of the ISO or a local area.
Reliability Must-Run Unit (RMR Unit)	A Generating Unit which is the subject of a Reliability Must-Run Contract.
Reliability Services Costs	The costs associated with services provided by the ISO: 1) that are deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area; and 2) whose costs are billed by the ISO to the Participating TO pursuant to the ISO Tariff. Reliability Services Costs include costs charged by the ISO to a Participating TO associated with service provided under an RMR Contract (Section 5.2.8), local out-of-market dispatch calls (Section 11.2.4.2.1) and Minimum Load Costs associated with units committed under the must-offer obligation for local reliability requirements (Section 5.11.6.1.4)
Reliability Upgrade	The transmission facilities, other than Direct Assignment Facilities, beyond the first point of interconnection necessary to interconnect a New Facility safely and reliably to the ISO Controlled Grid, which would not have been necessary but for the interconnection of a New Facility, including network upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of a New Facility to

the ISO Controlled Grid. Reliability Upgrades also include, consistent with WECC practice, the facilities necessary to mitigate any adverse impact a New Facility's interconnection may have on a path's WECC path rating.

<u>REMnet</u> The Wide Area Network through which the ISO acquires Meter Data.

Start-Up Cost Charge	The charge determined in accordance with Section 2.5.23.3.7.
Start-Up Cost Demand	The level of Demand specified in Section 2.5.23.3.7.3.
Start-Up Cost Invoice	The invoice submitted to the ISO in accordance with Section 2.5.23.3.7.6.
Start-Up Cost Trust Account	The trust account established in accordance with Section 2.5.23.3.7.2.
Start-Up Costs	The cost incurred by a particular Generating Unit from the time of first fire, the time of receipt of an ISO Dispatch instruction, or the time the unit was last synchornized to the grid, whichever is later, until the time the generating unit is synchronized or re-synchronized to the grid and producing Energy. Start-Up Costs are determined as the sum of (1) the cost of auxiliary power used during the start-up and (2) the number that is determined multiplying the actual amount of fuel consumed by the proxy gas price as determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas.

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notify each Scheduling Coordinator no later than 1:00 p.m. of the day prior to the Trading Day of their Ancillary Services schedules for the Day-Ahead and no later than one hour prior to the operating hour of their Ancillary Services schedules for the Hour-Ahead. The ISO Protocols set forth the information, which will be included in these schedules. Where long-term contracts are involved, the information may be treated as standing information for the duration of the contract.

If, at any time after the issuance of Final Day-Ahead Schedules for the Trading Day and before the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day, the ISO determines that it requires Ancillary Services in addition to those included in the Final Day-Ahead Schedule (in the appropriate Zone if procuring zonally), the ISO may procure such additional Ancillary Services by providing Scheduling Coordinators with amended supplier schedules for the Day-Ahead Markets that include Ancillary Services for which previously submitted (but not selected) bids remain available and have not previously been withdrawn. The ISO shall select such Ancillary Services in price merit order (and in the relevant Zone if the ISO is procuring Ancillary Services on a Zonal basis). Such amended supplier schedules shall be provided to the Scheduling Coordinators no later than the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day.

Once the ISO has given Scheduling Coordinators notice of the Day-Ahead and Hour-Ahead Schedules, these schedules represent binding commitments made in the markets between the ISO and the Scheduling Coordinators concerned, subject to any amendments issued as described above. Any minimum energy input and output associated with Regulation and Spinning Reserve services shall be the responsibility of the Scheduling Coordinator, or provided in accordance with the must-offer obligation as set forth in Section 5.11, as the ISO's auction does not compensate the Scheduling Coordinator for the minimum energy output of Generating Units bidding to provide these

services. Accordingly, except as set forth under Section 5.11, the Scheduling Coordinators shall adjust their schedules to accommodate the minimum outputs required by the Generating Units to facilitate delivery of Energy from Ancillary Services.

Notwithstanding the foregoing, a Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace that capacity in whole or in part from the ISO if the scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or if the Ancillary Service associated with a Generating Unit, Curtailable Demand, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduling Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replaced Ancillary Service shall be the Market Clearing Price in the Hour-Ahead Market for the Ancillary Service for the Settlement Period concerned for the Zone in which the Generating Units or other resources are located. The ISO will purchase the Ancillary Service concerned from another Scheduling Coordinator in the Hour-Ahead Market in accordance with the provisions of the ISO Tariff.

2.5.22 Rules For Real-Time Dispatch of Imbalance Energy Resources.

2.5.22.1 Overview. During real time, the ISO shall dispatch Generating Units, Loads and System Resources to procure Imbalance Energy. In addition, the ISO may also need to purchase additional Ancillary Services if the services arranged in advance are used to provide Imbalance Energy, and such depletion needs to be recovered to meet reliability contingency requirements.

the ISO will assess the Emissions Cost Charge in accordance with Section 2.5.23.3.6.4. Any outstanding Emissions Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay Emissions Costs is limited to the obligation to pay Emissions Cost Charges received. All disputes concerning payment of Emissions Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.

2.5.23.3.7 Start-Up Costs

2.5.23.3.7.1 Obligation to Pay Start-Up Cost Charges

Each Scheduling Coordinator shall be obligated to pay a charge which will be used to pay the verified Start-Up Costs incurred by a Must-Offer Generator as a direct result of an ISO Dispatch instruction, in accordance with this Section 2.5.23.3.7. Such Start-Up Costs shall include (1) fuel and (2) auxiliary power. The ISO shall levy this charge (the "Start-Up Cost Charge"), each month, against all Scheduling Coordinators based upon each Scheduling Coordinator's Control Area Gross Load and Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area. Scheduling Coordinators shall make payment for all Start-Up Cost Charges in accordance with the ISO Payments Calendar.

2.5.23.3.7.2 Start-Up Cost Trust Account

All Start-Up Cost Charges received by the ISO shall be deposited in the Start-Up Cost Trust Account. The Start-Up Cost Trust Account shall be an interest-bearing account separate from all other accounts maintained by the ISO, and no other funds shall be commingled in it at any time.

2.5.23.3.7.3 Rate For the Start-Up Cost Charge

The rate at which the ISO will assess the Start-Up Cost Charge shall be at the projected annual total of all Start-Up Costs incurred by Must-Offer Generators as a direct result of

ISO Dispatch instruction, adjusted for interest projected to be earned on the monies in the Start-Up Cost Trust Account, divided by the sum of the Control Area Gross Load and the projected Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area ("Start-Up Cost Demand"). The initial rate for the Start-Up Cost Charge, and all subsequent rates for the Start-Up Cost Charge, shall be posted on the ISO Home Page.

2.5.23.3.7.4 Adjustment of the Rate For the Start-Up Cost Charge

The ISO may adjust the rate at which the ISO will assess the Start-Up Cost Charge on a monthly basis, as necessary, to reflect the net effect of the following:

(a) the difference, if any, between actual Start-Up Cost Demand and projected Start-Up Cost Demand;

(b) the difference, if any, between the projections of the Start-Up Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instructions and the actual Start-Up Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instructions as invoiced to the ISO and verified in accordance with this Section 2.5.23.3.7; and

(c) the difference, if any, between actual and projected interest earned on funds in the Start-Up Cost Trust Account.

The adjusted rate at which the ISO will assess the Start-Up Cost Charge shall take effect on a prospective basis on the first day of the next calendar month. The ISO shall publish all data and calculations used by the ISO as a basis for such an adjustment on the ISO Home Page at least five (5) days in advance of the date on which the new rate shall go into effect.

2.5.23.3.7.5 Credits and Debits of Start-Up Cost Charges Collected from Scheduling Coordinators

In addition to the surcharges or credits permitted under Section 11.6.3.3 of this ISO Tariff, the

ISO may credit or debit, as appropriate, the account of a Scheduling Coordinator for any over- or under-assessment of Start-Up Cost Charges that the ISO determines occurred due to the error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

2.5.23.3.7.6 Submission of Start-Up Cost Invoices

Scheduling Coordinators for Must-Offer Generators that incur Start-Up Costs as a direct result of an ISO Dispatch instruction or if the ISO revokes a waiver from compliance with the must-offer obligation while the unit is off-line in accordance with Section 5.11.6 of this ISO Tariff, and Scheduling Coordinators for Generating Units operating under Condition 2 of the relevant RMR Contract which are called out-of-market in accordance with Section 11.2.4.2 of this ISO Tariff or who are due an additional payment for a start-up under the RMR Contract in accordance with Section 11.2.4.2 of this ISO Tariff may submit to the ISO an invoice in the form specified on the ISO Home Page (the "Start-Up Cost Invoice") for the recovery of such Start-Up Costs. Such Start-Up Costs shall not exceed the costs which would be incurred within the start-up time for a unit specified in Schedule 1 of the Participating Generator Agreement. Start-Up Cost Invoices shall use the applicable proxy figure for natural gas costs as determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas. Start-Up Cost Invoices shall specify the amount of auxiliary power used during the start-up and the actual price paid for that power. Start-Up Cost Invoices shall not include any Start-Up Costs specified in an RMR Contract for a unit owned or controlled by a Must-Offer Generator.

2.5.23.3.7.7 Payment of Start-Up Cost Invoices

The ISO shall pay Scheduling Coordinators for all Start-Up Costs submitted in a Start-Up Cost Invoice and demonstrated to be a direct result of an ISO Dispatch instruction. The ISO shall pay such Start-Up Cost Invoices each month in accordance with the ISO Payments Calendar from the funds available in the Start-Up Cost Trust Account. To the extent there are insufficient funds available in the Start-Up Cost Trust Account in any month to pay all Start-Up Costs submitted in a Start-Up Cost Invoice and demonstrated to be a direct result of an ISO Dispatch instruction, the ISO shall make pro rata payment of such Start-Up Costs and shall adjust the rate at which the ISO will assess the Start-Up Cost Charge in accordance with Section 2.5.23.3.7.4. Any outstanding Start-Up Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay Start-Up Costs is limited to the obligation to pay Start-Up Cost Charges received. All disputes concerning payment of Start-Up Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.

2.5.23.3.8 [Not Used]

2.5.23.3.8.1 [Not Used]

under this ISO Tariff) subject to control by the ISO during a System Emergency and in circumstances in which the ISO considers that a System Emergency is imminent or threatened. The ISO shall, subject to Section 5.6.2, have the authority to instruct a Participating Generator to bring its Generating Unit on-line, off-line, or increase or curtail the output of the Generating Unit and to alter scheduled deliveries of Energy and Ancillary Services into or out of the ISO Controlled Grid, if such an instruction is reasonably necessary to prevent an imminent or threatened System Emergency or to retain Operational Control over the ISO Controlled Grid during an actual System Emergency. The ISO shall have the authority to instruct an RMR Unit whose owner has selected Condition 2 of its RMR Contract to start-up and change its output if the ISO has reasonably used all other available and effective resources to prevent a threatened System Emergency without declaring that a System Emergency exists. If the ISO so instructs a Condition 2 RMR Unit, it shall compensate that unit in accordance with Section 11.2.4.2 and allocate the costs in accordance with Section 11.2.4.2.1.1.

5.6.2 The ISO shall, where reasonably practicable, utilize Ancillary Services which it has the contractual right to instruct and which are capable of contributing to containing or correcting the actual, imminent or threatened System Emergency prior to issuing instructions to a Participating Generator under Section 5.6.1.

5.6.3 [Not Used]

each non-hydroelectric Generating Unit located in California they own or control: (i) the Unit's minimum operating level; (ii) the Unit's maximum operating level; and (iii) the Unit's ramp rates at all operating levels; and (iv) such other information the ISO determines is necessary to determine available generation and to dispatch Must-Offer Generators. In addition, Must-Offer Generators that are not Participating Generators must, consistent with the notification obligations of Participating Generators and in order to comply with the intent of this Section 5.11, notify the ISO, as soon as practicable, of any Planned Maintenance Outages, Forced Outages, Force Majeure Event outages or any other reductions in their maximum operating levels.

5.11.4 Obligation To Offer Available Capacity

Except as set forth in Section 5.11.6, all Must-Offer Generators shall offer to sell in the ISO's Real Time Market for Imbalance Energy, in all hours, all their Available Generation as defined in Section 5.11.2.

5.11.5 Submission of Bids and Applicability of the Proxy Price

For each Operating Hour, Must-Offer Generators shall submit Supplemental Energy bids for all of their Available Generation to the ISO in accordance with Section 2.5.22.4. In addition, the ISO shall calculate for each gas-fired Must-Offer Generator, in accordance with Section 2.5.23, a Proxy Price for Energy.

If a Must-Offer Generator fails to submit a Supplemental Energy bid for any portion of its Available Generation for any Dispatch Interval, the unbid quantity of the Must-Offer Generator's Available Generation will be deemed by the ISO to be bid at the Must-Offer Generator's Proxy Price for that hour if: (i) the applicable Generating Unit is a gas-fired unit and (ii) the Must-Offer Generator has provided the ISO with adequate data in compliance with Sections 2.5.23.3.3 and 5.11.3 for the applicable Generating Unit. For all other Generating Units owned or controlled by a Must-Offer Generator, the unbid quantity of the Must-Offer Generator's Available Generation will be deemed by the ISO to be bid and settled in accordance with Section 11.2. In order to dispatch resources providing Imbalance Energy in proper merit order, the ISO will insert this unbid quantity into the Must-Offer Generator's Supplemental Energy bid curve above any lower-priced segments of the bid curve and below any higher-priced segments of the bid curve as necessary to maintain a non-decreasing bid curve over the entire range of the Must-Offer Generator's Available Generation.

5.11.6 Must-Offer Obligation Process

Must-Offer Generators may seek a waiver of the obligation to offer all available capacity, as set forth in Section 5.11.4 of this ISO Tariff, for one or more of their Generating Units for periods other than Self-Commitment Periods. Self-Commitment Periods are defined as the hours for which Must-Offer Generators submit Day-Ahead Energy Schedules. Self-Commitment Periods determined from Day-Ahead Schedules shall be extended by the ISO as necessary to accommodate Generating Unit minimum up and down times such that the scheduled operation is feasible.

All other Must-Offer Generators obligated under the must-offer obligation that have not submitted Day-Ahead Energy Schedules will be deemed to have requested a waiver, either implicitly or explicitly, of the obligation to offer all available capacity. If conditions permit, and at the ISO's non-discriminatory and sole discretion, the ISO may grant waivers and allow a Must-Offer Generator to remove one or more Generating Units from service. The Self-Commitment Period defined by a Generating Unit's Day-Ahead schedules (plus any additional time necessary to accommodate minimum up and minimum down times) shall remain in effect for that Generating Unit even if a Must-Offer Generator nullifies the Day-Ahead Schedules submitted for that unit in the Hour-Ahead Market. If a Must-Offer Generator requests a waiver for a Generating Unit for its Self-Commitment Period, the ISO may grant the waiver, but if the ISO denies the waiver, the unit shall not be eligible to recover Minimum Load Costs incurred during any Self-Commitment Period as set forth in Section 5.11.6.1.1.

The hours outside of Self-Commitment Periods for which waivers are not granted shall constitute Waiver Denial Periods. A Waiver Denial Period shall be extended as necessary to accommodate Generating Unit minimum up and down times. Units shall be on-line in real time during both Self-Commitment and Waiver Denial Periods, or they will be in violation of the must-offer obligation. Exceptions shall be allowed for verified forced outages. The ISO may revoke waivers as necessary due to outages, changes in Load forecasts, or changes in system conditions. The ISO shall determine which waiver(s) will be revoked, and shall notify the relevant Scheduling Coordinator(s). The ISO shall inform a Must-Offer Generator that its Waiver request has been accepted, denied, or revoked, and shall provide the Must-Offer Generator with the reason(s) for the decision, which reasons shall be non-discriminatory. The ISO will: (1) notify Must-Offer Generators of the ISO decisions on pending Waiver requests received no later than 10:00 a.m. (beginning of Hour Ending 11) no later than 11:30 a.m. (middle of Hour Ending 12) on the day before the operating day for which the Waivers are requested; (2) at any time but no later than 11:30 a.m. on the following day, notify Must-Offer Generators of the ISO decisions on Waiver requests that were submitted to the ISO after 10:00 a.m. (beginning of Hour Ending 11) on the day before; (3) end Waiver Denial Periods at any time; and (4) revoke Waivers at any time, while making best attempts to revoke a Waiver at least 90 minutes prior to time a unit would be required to be on-line generating at its Pmin.

5.11.6.1 Recovery of Minimum Load Costs By Must-Offer Generators

5.11.6.1.1 Eligibility

Units from Must-Offer Generators that incur Minimum Load Costs during Self-Commitment Periods or during hours for which the ISO has granted to them a waiver shall not be eligible to recover such costs for such hours. When a Must-Offer Generator has a Final Hour-Ahead Energy Schedule other than a Schedule to a unit-specific Demand ID used for the purpose of scheduling minimum load energy as set forth in Section 5.11.6, the Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on a 10-minute Settlement Interval basis, a Must-Offer Generator generating at minimum load in compliance with the must-offer obligation, produces a quantity of Energy that varies by more than the Tolerance Band, the Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such Settlement Intervals during hours within a Waiver Denial Period. When, on a Settlement Interval basis, a Must-Offer Generator's resource produces a quantity of Energy above minimum load due to an ISO Dispatch Instruction, the Must-Offer Generator shall recover its Minimum Load Costs and its bid costs, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band. Subject to the foregoing eligibility restrictions set forth in this section, the ISO shall guarantee recovery of the Minimum Load Costs of an otherwise eligible Must-Offer Generator for each Settlement Interval during hours within a Waiver Denial Period as follows: (1) First, ISO will pre-dispatch for real time the minimum load Energy from Must-Offer Generators that have been denied waivers for each hour within a Waiver Denial Period; (2) This minimum load Energy will be accounted as Instructed

Imbalance Energy for each Settlement Interval within the relevant hour and be settled at the Resource-Specific Settlement Interval Ex Post Price; (3) To the extent the Instructed Imbalance Energy payments are not sufficient to cover the generator's Minimum Load Cost as defined in Section 5.11.6.1.2 of this Tariff, the generator will also receive an uplift payment for its Minimum Load Cost compensation for the relevant eligible Settlement Intervals of hours during the Waiver Denial Period that the Generating Unit runs at minimum load in compliance with the must-offer obligation; and (4) To the extent the Generator is dispatched for real time Imbalance Energy above its minimum load for any Dispatch Interval within an hour during the Waiver Denial Period, the Generator will be eligible for Bid Cost Recovery, as set forth in Section 11.2.4.1.1.1.

5.11.6.1.2 Minimum Load Costs

The Minimum Load Costs shall be calculated as the sum, for all eligible hours in the Waiver Denial Period and Settlement Periods in which the unit generated in response to an ISO Dispatch Instruction, of: 1) the product of the unit's average heat rate (as determined by the ISO from the data provided in accordance with Section 2.5.23.3.3) at the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in Schedule A to the resource's Reliability Must-Run Contract if the resource is subject to a Reliability Must-Run Contract, or, if the resource is not subject to a Reliability Must-Run Contract or has so directed in Schedule A to its Reliability Must-Run Contract, the ISO Master File as amended through notification to the ISO via SLIC and the gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas; and 2) the product of the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC; and \$6.00/MWh.

5.11.6.1.2.1 Operating Must-Offer Generating Units above Minimum Load

If, during a Waiver Denial Period, the ISO requires that a Generating Unit operate at a level above its minimum load operating so as to be able to respond effectively to real time Dispatch Instructions, the ISO shall operate that Generating Unit at such an operating level. The ISO shall pay the Minimum Load Costs set forth in Section 5.11.6.1.2 for the amount of the Generating Unit's Minimum Load. For the amount of Energy above Minimum Load to the Unit's required operating level, the ISO shall pay the greater of the product of such amount of Energy and (1) the price for instructed Imbalance Energy or (2) the sum of (a) the product of (i) the Generating Unit's incremental heat rate at the required operating level, and (ii) the proxy figure for natural gas costs set forth in Section 2.5.23.4, and (b) $6.00.

5.11.6.1.3 Invoicing Minimum Load Costs

The ISO shall determine each Scheduling Coordinator's Minimum Load Costs and make payments for these costs as part of the ISO's market settlement process. Scheduling Coordinators may 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 defined in Section 5.11.6.1.1, that the unit generated above minimum load in compliance with ISO Dispatch Instructions.

5.11.6.2 Criteria for Issuing Must-Offer Waivers

The ISO shall grant waivers so as to: 1) provide sufficient on-line generating capacity to meet operating reserve requirements; and 2) account for other physical operating constraints, including Generating Unit minimum up and down times. The ISO shall grant, deny or revoke waivers using a security-constrained unit commitment software application to minimize start-up and Minimum Load Costs.

Scheduling Coordinator for each Settlement Period for each such resource by application of either of the following payment options described below. For resources subject to a Reliability Must-Run Contract, the ISO will dispatch such resources according to the terms of the RMR Contract, except as provided for below. In circumstances where an RMR Unit would be used to resolve Intra-Zonal Congestion and there are no such RMR Units available, a resource may be called upon and paid under this Section to resolve the Intra-Zonal Congestion.

By December 31 of each year for the following calendar year, each Scheduling Coordinator for a resource shall select one of the following payment options for each resource it schedules:

(a) the Uninstructed Imbalance Energy charge price as calculated in accordance with Section 2.5.23.2.2 (i.e., using the Hourly Ex Post Price) or

(b) a calculated price:

(i) for decremental dispatch orders that is an Energy payment to the ISO that is equal to the Market Clearing Price for the relevant Settlement Period for the applicable Energy market less verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's Dispatch Instruction and that the Scheduling Coordinator or Generator was not able to eliminate or reduce despite the application of best efforts, if the Scheduling Coordinator provides the resource's daily gas imbalance charges to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched; and

(ii) for incremental dispatch orders is the sum of: 1) a capacity payment equal to the average Day-Ahead Market prices for Spinning Reserve and Non-Spinning Reserve for the three (3) most recent similar days for the same Settlement Period for which the resource is dispatched; 2) an Energy payment equal to the average calculated using the ISO Real Time Market Energy prices for the three (3) most recent similar days for the same Settlement Period for which the resource is dispatched; 3) such resource's verifiable Start-Up Costs, if the start-up was solely attributable to the ISO's Dispatch Instruction and if the Scheduling Coordinator provides the resource's Start-Up Costs to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched; and 4) verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's Dispatch Instruction and that the Scheduling Coordinator or Generator was not able to eliminate or reduce despite the application of best efforts, if the Scheduling Coordinator provides the resource's daily gas imbalance charges to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched. References to "similar days" in this Section refer to Business Days when the resource is dispatched on a Business Day and otherwise to days that are not Business Days.

To the extent a Scheduling Coordinator does not specify a payment option, the ISO will apply the payment provisions of the payment option described in Section 11.2.4.2(a).

If the ISO Dispatches an RMR Unit that has selected Condition 2 of its RMR Contract to start-up or provide energy other than a start-up or energy requested pursuant to the RMR Contract, the ISO shall pay as follows:

1) if, as determined by the ISO, the sum of the service hours, service MWh or start-ups

from service not under the RMR Contract and RMR Contract Counted Service Hours, Counted MWh, or Counted Start-ups does not exceed the applicable RMR Contract Service Limit, the ISO shall pay (a) for energy, the rate set forth in either Equation 1a or 1b below, as appropriate and (b) for a start-up, the rate specified in Schedule D to the applicable RMR Contract.

2) Equation 1a (for Units with input/output data in polynomial form) or Equation 1b (for Units with input/output data in exponential form) as defined below shall be used to calculate the Energy rate for MWh of Instructed Imbalance Energy delivered:

Equation 1a

$$\text{Energy Price (\$/MWh)} = \frac{(AX^3 + BX^2 + CX + D) * P * E}{X} + \text{Variable O\&M Rate}$$

Equation 1b

$$\text{Energy Price (\$/MWh)} = \frac{A * (B + \text{Cm } X + De^{FX}) * P * E}{X} + \text{Variable O\&M Rate}$$

Where:

- for Equation 1a, A, B, C, D and E are the coefficients given in Table C1-7a of the applicable RMR Contract;
- for Equation 1b, A, B, C, D, E and F are the coefficients given in Table C1-7b of the applicable RMR Contract;
- X is the Unit output level during the applicable settlement period, MWh;
- P is the Hourly Fuel Price as calculated by Equation C1-8 in Schedule C using the Commodity Prices in accordance with the applicable RMR Contract;
- Variable O&M Rate ($/MWh): as shown on Table C1-18 of the applicable RMR Contract.

3) If, as determined by the ISO, the sum of the service hours, service MWh or start-ups from service instructed by the ISO not under the RMR Contract and RMR Contract Counted Service Hours, Counted MWh, or Counted Start-ups, as applicable, exceeds the applicable RMR Contract Service Limit, the ISO shall pay:

a) if the Owner has elected Option A of Schedule G, two times the start-up cost specified in Schedule D to the applicable RMR Contract for any start-up incurred, and 1.5 times the rate specified in Equation 1a or 1b above times the amount of energy delivered in response to the ISO's instruction;

(b) if the Owner has elected Option B of Schedule G, three times the start-up cost specified in Schedule D to the applicable RMR Contract for any start-up incurred, and the rate specified in Equation 1a or 1b above times the amount of energy delivered in response to the ISO's instruction.

If the ISO Dispatches an RMR Unit pursuant to under the RMR Contract when the sum of the service hours, service MWh or start-ups from service not under the RMR Contract and the RMR Contract Counted Service Hours, Counted MWh or Counted Start-ups, as applicable, has exceeded the applicable RMR Contract Service Limit, the ISO shall pay the Scheduling Coordinator an additional amount so that the Scheduling Coordinator receives, in total, from the payment provided pursuant to the RMR Contract and the additional amount, the rates specified in Schedule G to the RMR Contract for the RMR Energy provided or for the RMR Start-Up Costs incurred until either the RMR Contract Counted MWh, Counted Service Hours or Counted Start-ups exceed the relevant RMR Contract Service Limit.

11.2.4.2.1 Allocation of Costs Resulting From Dispatch Instructions

Pursuant to Section 11.2.4.1, the ISO may, at its discretion, Dispatch any Participating Generator, Participating Load and dispatchable System Resource that has not bid into the Imbalance Energy or

Ancillary Services markets, to avoid an intervention in market operations or to prevent or relieve a System Emergency. Such Dispatch may result from, among other things, planned and unplanned transmission facility Outages; bid insufficiency in the Ancillary Services and real-time Energy markets; and location-specific requirements of the ISO. The cost associated with each Dispatch instruction is broken into two components:

a) the portion of the Energy payment at or below the Market Clearing Price ("MCP") for the Settlement Interval, and

b) the portion of the Energy payment above the MCP, if any, for the Settlement Interval.

For each Settlement Interval, costs above the MCP incurred by the ISO for such Dispatch instructions necessary as a result of a transmission facility Outage or in order to satisfy a location-specific requirement in that Settlement Interval shall be payable to the ISO by the Participating Transmission Owner in whose PTO Service Territory the transmission facility is located or the location-specific requirement arose. The costs incurred by the ISO for such Dispatch instructions for reasons other than for a transmission facility Outage or a location-specific requirement will be recovered in the same way as for Instructed Imbalance Energy.

11.2.4.2.1.1 Allocation of Costs from Out-Of-Market calls to Condition 2 RMR Units

All costs associated with energy provided by a Condition 2 RMR unit operating other than according to a dispatch notice issued under the RMR Contract shall be allocated in accordance with Section 11.2.4.2.1. Until either the RMR Contract Counted MWh, Counted Service Hours or Counted Start-ups exceed the relevant RMR Contract Service Limit, any cost incurred for energy provided under the RMR Contract above the rate specified in equation 1a or 1b as set forth in Section 11.2.4.2 shall be allocated in accordance with Section 11.2.4.2.1, not to the Responsible Utility.

Start-Up Costs for Condition 2 RMR Units providing service outside the RMR Contract, and any additional Start-Up Cost associated with a Condition 2 RMR Unit providing service under the RMR Contract when the unit's total service has exceeded an RMR Contract Service Limit but neither the RMR Contract Counted MWH, Counted Hours or Counted Start-ups have exceeded the applicable RMR Contract Service Limit, shall be invoiced in accordance with Section 2.5.23.3.7.6 and collected in accordance with Section 2.5.23.3.7.1.

11.2.4.2.2 Allocation of Above-MCP Costs For Accepted Bids

For each Settlement Interval, the at or below-MCP costs incurred as a result of accepted bids in the ISO Imbalance Energy Markets shall be allocated in accordance with 11.2.4.1. Allocation of above-MCP costs for accepted bids in the ISO Imbalance Energy Markets shall be in accordance with this Section 11.2.4.2.2 as follows.

11.2.4.2.2.1 Allocation of Bid Costs Above the Maximum Bid Level

For each Settlement Interval, costs that are both above the MCP and above the Maximum Bid Level, incurred by the ISO as a result of Instructed Imbalance Energy and Dispatch instructions for reasons other than for a transmission facility Outage or a location-specific requirement shall

Reliability Must-Run Contract (RMR Contract)	A Must-Run Service Agreement between the owner of an RMR Unit and the ISO.
Reliability Must-Run Generation (RMR Generation)	Generation that the ISO determines is required to be on line to meet Applicable Reliability Criteria requirements. This includes i) Generation constrained on line to meet NERC and WECC reliability criteria for interconnected systems operation; ii) Generation needed to meet Load demand in constrained areas; and iii) Generation needed to be operated to provide voltage or security support of the ISO or a local area.
Reliability Must-Run Unit (RMR Unit)	A Generating Unit which is the subject of a Reliability Must-Run Contract.
Reliability Services Costs	The costs associated with services provided by the ISO: 1) that are deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area; and 2) whose costs are billed by the ISO to the Participating TO pursuant to the ISO Tariff. Reliability Services Costs include costs charged by the ISO to a Participating TO associated with service provided under an RMR Contract (Section 5.2.8), local out-of-market dispatch calls (Section 11.2.4.2.1) and Minimum Load Costs associated with units committed under the must-offer obligation for local reliability requirements (Section 5.11.6.1.4)
Reliability Upgrade	The transmission facilities, other than Direct Assignment Facilities, beyond the first point of interconnection necessary to interconnect a New Facility safely and reliably to the ISO Controlled Grid, which would not have been necessary but for the interconnection of a New Facility, including network upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of a New Facility to

the ISO Controlled Grid. Reliability Upgrades also include, consistent with WECC practice, the facilities necessary to mitigate any adverse impact a New Facility's interconnection may have on a path's WECC path rating.

REMnet The Wide Area Network through which the ISO acquires Meter Data.

Start-Up Cost Charge	The charge determined in accordance with Section 2.5.23.3.7.
Start-Up Cost Demand	The level of Demand specified in Section 2.5.23.3.7.3.
Start-Up Cost Invoice	The invoice submitted to the ISO in accordance with Section 2.5.23.3.7.6.
Start-Up Cost Trust Account	The trust account established in accordance with Section 2.5.23.3.7.2.
Start-Up Costs	The cost incurred by a particular Generating Unit from the time of first fire, the time of receipt of an ISO Dispatch instruction, or the time the unit was last synchronized to the grid, whichever is later, until the time the generating unit is synchronized or re-synchronized to the grid and producing Energy. Start-Up Costs are determined as the sum of (1) the cost of auxiliary power used during the start-up and (2) the number that is determined multiplying the actual amount of fuel consumed by the proxy gas price as determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas.

ATTACHMENT B1

2.5.21 Scheduling of Units to Provide Ancillary Services.

The ISO shall prepare supplier schedules for Ancillary Services (both self-provided and purchased by the ISO) for the Day-Ahead and the Hour-Ahead Markets. The ISO shall notify each Scheduling Coordinator no later than 1:00 p.m. of the day prior to the Trading Day of their Ancillary Services schedules for the Day-Ahead and no later than one hour prior to the operating hour of their Ancillary Services schedules for the Hour-Ahead. The ISO Protocols set forth the information, which will be included in these schedules. Where long-term contracts are involved, the information may be treated as standing information for the duration of the contract.

If, at any time after the issuance of Final Day-Ahead Schedules for the Trading Day and before the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day, the ISO determines that it requires Ancillary Services in addition to those included in the Final Day-Ahead Schedule (in the appropriate Zone if procuring zonally), the ISO may procure such additional Ancillary Services by providing Scheduling Coordinators with amended supplier schedules for the Day-Ahead Markets that include Ancillary Services for which previously submitted (but not selected) bids remain available and have not previously been withdrawn. The ISO shall select such Ancillary Services in price merit order (and in the relevant Zone if the ISO is procuring Ancillary Services on a Zonal basis). Such amended supplier schedules shall be provided to the Scheduling Coordinators no later than the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day.

Once the ISO has given Scheduling Coordinators notice of the Day-Ahead and Hour-Ahead Schedules, these schedules represent binding commitments made in the markets between the ISO and the Scheduling Coordinators concerned, subject to any amendments issued as described above. Any minimum energy input and output associated with Regulation and Spinning Reserve services shall be the responsibility of the Scheduling Coordinator, <u>or provided in accordance with the must-offer obligation as set forth in Section 5.11,</u> as the ISO's auction does not compensate the Scheduling Coordinator for the minimum energy output of Generating Units bidding to provide these services. Accordingly, except as set forth under Section 5.11, the Scheduling Coordinators shall adjust their schedules to accommodate the minimum outputs required by the Generating Units to facilitate delivery of Energy from Ancillary Services~~included on the Schedules~~.

Notwithstanding the foregoing, a Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace that capacity in whole or in part from the ISO if the scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or if the Ancillary Service associated with a Generating Unit, Curtailable Demand, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduling Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replaced Ancillary Service shall be the Market Clearing Price in the Hour-Ahead Market for the Ancillary Service for the Settlement Period concerned for the Zone in which the Generating Units or other resources are located. The ISO will purchase the Ancillary Service concerned from another Scheduling Coordinator in the Hour-Ahead Market in accordance with the provisions of the ISO Tariff.

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2.5.23.3.7 Start-Up Fuel Costs

2.5.23.3.7.1 Obligation to Pay Start-Up Fuel Cost Charges

Each Scheduling Coordinator shall be obligated to pay a charge which will be used to pay the verified Start-Up Fuel Costs incurred by a Must-Offer Generator as a direct result of an ISO Dispatch instruction, in accordance with this Section 2.5.23.3.7. Such Start-Up Costs shall include (1) fuel and (2) auxiliary power. The ISO shall levy this charge (the "Start-Up ~~Fuel~~ Cost Charge"), each month, against all Scheduling Coordinators based upon each Scheduling Coordinator's Control Area Gross Load and Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area. Scheduling Coordinators shall make payment for all Start-Up ~~Fuel~~ Cost Charges in accordance with the ISO Payments Calendar.

2.5.23.3.7.2 Start-Up ~~Fuel~~ Cost Trust Account

All Start-Up ~~Fuel~~ Cost Charges received by the ISO shall be deposited in the Start-Up ~~Fuel~~ Cost Trust Account. The Start-Up ~~Fuel~~ Cost Trust Account shall be an interest-bearing account separate from all other accounts maintained by the ISO, and no other funds shall be commingled in it at any time.

2.5.23.3.7.3 Rate For the Start-Up ~~Fuel~~ Cost Charge

The rate at which the ISO will assess the Start-Up ~~Fuel~~ Cost Charge shall be at the projected annual total of all Start-Up ~~Fuel~~ Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instruction, adjusted for interest projected to be earned on the monies in the Start-Up ~~Fuel~~ Cost Trust Account, divided by the sum of the Control Area Gross Load and the projected Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area ("Start-Up ~~Fuel~~ Cost Demand"). The initial rate for the Start-Up ~~Fuel~~ Cost Charge, and all subsequent rates for the Start-Up ~~Fuel~~ Cost Charge, shall be posted on the ISO Home Page.

2.5.23.3.7.4 Adjustment of the Rate For the Start-Up ~~Fuel~~ Cost Charge

The ISO may adjust the rate at which the ISO will assess the Start-Up ~~Fuel~~ Cost Charge on a monthly basis, as necessary, to reflect the net effect of the following:

(a) the difference, if any, between actual Start-Up ~~Fuel~~ Cost Demand and projected Start-Up ~~Fuel~~ Cost Demand;

(b) the difference, if any, between the projections of the Start-Up ~~Fuel~~ Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instructions and the actual Start-Up ~~Fuel~~ Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instructions as invoiced to the ISO and verified in accordance with this Section 2.5.23.3.7; and

(c) the difference, if any, between actual and projected interest earned on funds in the Start-Up ~~Fuel~~ Cost Trust Account.

The adjusted rate at which the ISO will assess the Start-Up ~~Fuel~~ Cost Charge shall take effect on a prospective basis on the first day of the next calendar month. The ISO shall publish all data and calculations used by the ISO as a basis for such an adjustment on the ISO Home Page at least five (5) days in advance of the date on which the new rate shall go into effect.

2.5.23.3.7.5 Credits and Debits of Start-Up ~~Fuel~~ Cost Charges Collected from Scheduling Coordinators

In addition to the surcharges or credits permitted under Section 11.6.3.3 of this ISO Tariff, the ISO may credit or debit, as appropriate, the account of a Scheduling Coordinator for any over- or under-assessment of Start-Up ~~Fuel~~ Cost Charges that the ISO determines occurred due to the error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

2.5.23.3.7.6 Submission of Start-Up ~~Fuel~~ Cost Invoices

Scheduling Coordinators for Must-Offer Generators that incur Start-Up ~~Fuel~~ Costs as a direct result of an ISO Dispatch instruction or if the ISO revokes a waiver from compliance with the must-offer obligation while the unit is off-line in accordance with Section 5.11.6 of this ISO Tariff, and Scheduling Coordinators for Generating Units operating under Condition 2 of the relevant RMR Contract which are called out-of-market in accordance with Section 11.2.4.2 of this ISO Tariff or who are due an additional payment for a start-up under the RMR Contract in accordance with Section 11.2.4.2 of this ISO Tariff may submit to the ISO an invoice in the form specified on the ISO Home Page (the "Start-Up ~~Fuel~~ Cost Invoice") for the recovery of such Start-Up ~~Fuel~~ Costs. Such Start-Up ~~Fuel~~ Costs shall not exceed the costs which would be incurred within the start-up time for a unit specified in Schedule 1 of the Participating Generator Agreement. Start-Up ~~Fuel~~ Cost Invoices shall use the applicable proxy figure for natural gas costs as determined ~~in~~ by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas~~accordance with Section 2.5.23.3.4 and posted on the ISO Home Page~~. Start-Up Cost Invoices shall specify the amount of auxiliary power used during the start-up and the actual price paid for that power. Start-Up ~~Fuel~~ Cost Invoices shall not include any Start-Up ~~Fuel~~ Costs specified in an RMR Contract for a unit owned or controlled by a Must-Offer Generator.

2.5.23.3.7.7 Payment of Start-Up ~~Fuel~~ Cost Invoices

The ISO shall pay Scheduling Coordinators for all Start-Up ~~Fuel~~ Costs submitted in a Start-Up ~~Fuel~~ Cost Invoice and demonstrated to be a direct result of an ISO Dispatch instruction. The ISO shall pay such Start-Up ~~Fuel~~ Cost Invoices each month in accordance with the ISO Payments Calendar from the funds available in the Start-Up ~~Fuel~~ Cost Trust Account. To the extent there are insufficient funds available in the Start-Up ~~Fuel~~ Cost Trust Account in any month to pay all Start-Up ~~Fuel~~ Costs submitted in a Start-Up ~~Fuel~~ Cost Invoice and demonstrated to be a direct result of an ISO Dispatch instruction, the ISO shall make pro rata payment of such Start-Up ~~Fuel~~ Costs and shall adjust the rate at which the ISO will assess the Start-Up ~~Fuel~~ Cost Charge in accordance with Section 2.5.23.3.7.4. Any outstanding Start-Up ~~Fuel~~ Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay Start-Up ~~Fuel~~ Costs is limited to the obligation to pay Start-Up ~~Fuel~~ Cost Charges received. All disputes concerning payment of Start-Up ~~Fuel~~ Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.

* * *

5.6.1 All Generating Units, System Units and System Resources that are owned or controlled by a Participating Generator are (without limitation to the ISO's other rights under this ISO Tariff) subject to control by the ISO during a System Emergency and in circumstances in which the ISO considers that a System Emergency is imminent or threatened. The ISO shall, subject to Section 5.6.2, have the authority to instruct a Participating Generator to bring its Generating Unit on-line, off-line, or increase or curtail the output of the Generating Unit and to alter scheduled deliveries of Energy and Ancillary Services into or out of the ISO Controlled Grid, if such an instruction is reasonably necessary to prevent an imminent or threatened System Emergency or to retain Operational Control over the ISO Controlled Grid during an actual System Emergency. The ISO shall have the authority to instruct an RMR Unit whose owner has selected Condition 2 of its RMR Contract to start-up and change its output if the ISO has reasonably used all other available and effective resources to prevent a threatened System Emergency without declaring that a System Emergency exists. If the ISO so instructs a Condition 2 RMR Unit, it shall compensate that unit in accordance with Section 11.2.4.2 and allocate the costs in accordance with Section 11.2.4.2.1.1.

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5.11.4 Obligation To Offer Available Capacity

Except as set forth in Section 5.11.6, a~~A~~ll Must-Offer Generators shall offer to sell in the ISO's Real Time Market for Imbalance Energy, in all hours, all their Available Generation as defined in Section 5.11.2.

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5.11.6 ~~Waiver of~~ Must-Offer Obligation Process

Must-Offer Generators may seek a waiver of the obligation to offer all available capacity, as set forth in Section 5.11.4 of this ISO Tariff, for one or more of their Generating Units for periods other than Self-Commitment Periods.~~,~~ Self-Commitment Periods ~~which~~ are defined as the hours for which ~~when~~ Must-Offer Generators submit Day-Ahead Energy Schedules ~~or are awarded Ancillary Services bids or self-provision schedules~~. Self-Commitment Periods determined from Day-Ahead Schedules shall be extended by the ISO as necessary to accommodate Generating Unit minimum up and down times such that the scheduled operation is feasible. All other Must-Offer Generators obligated under the must-offer obligation that have not submitted Day-Ahead Energy Schedules will be deemed to have requested a waiver, either implicitly or explicitly, of the obligation to offer all available capacity. If conditions permit, and at the ISO's non-discriminatory and sole discretion, the ISO may grant waivers and allow a Must-Offer Generator to remove one or more Generating Units from service ~~during hours outside Self-Commitment Periods~~. The Self-Commitment Period defined by a Generating Unit's Day-Ahead schedules (plus any additional time necessary to accommodate minimum up and minimum down times) shall remain in effect for that Generating Unit even if a Must-Offer Generator nullifies the Day-Ahead Schedules submitted for that unit in the Hour-Ahead Market. If a Must-Offer Generator requests a waiver for a Generating Unit for its Self-Commitment Period, the ISO may grant the waiver, but if the ISO denies the waiver, the unit shall not be eligible to recover Minimum Load Costs incurred during any Self-Commitment Period as set forth in Section 5.11.6.1.1. ~~The ISO shall grant waivers so as to: 1) provide sufficient on-line generating capacity to meet Operating Reserve requirements; and 2) account for other physical operating constraints, including Generating Unit minimum up and down times.~~ The hours outside of Self-Commitment Periods for which waivers are not granted shall constitute Waiver Denial Periods. A~~The~~ Waiver Denial Period shall be extended as necessary to accommodate Generating Unit minimum up and down times. Units shall be on-line in real time during both Self-Commitment and Waiver Denial Periods, or they will be in violation of the must-offer obligation. Exceptions shall be allowed for verified forced outages. ~~The must-offer obligation will remain in effect for a unit's Self-Commitment Period even if the Must-Offer Generator nullifies its Day-Ahead Schedules for Energy or buys back its Day-Ahead Schedules for a unit in the Hour-Ahead Market.~~ The ISO may revoke waivers as necessary due to outages, changes in Load forecasts, or changes in system conditions. The ISO shall determine which waiver(s) will be revoked, and shall notify the relevant Scheduling Coordinator(s). The ISO shall inform a Must-Offer Generator that its Waiver request has been accepted, denied, or revoked, and shall provide the Must-Offer Generator with the reason(s) for the decision, which reasons shall be non-discriminatory. The ISO will: (1) notify Must-Offer Generators of the ISO decisions on pending Waiver requests received no later than 10:00 a.m.~~6:00 p.m~~. (beginning of Hour Ending 11~~9~~) no later than 11:30 a.m.~~8:00 p.m~~. (middle of Hour Ending 12~~beginning of Hour Ending 21~~) on the day before the operating day for which the Waivers are requested; (2) at any time but no later than 11:30 a.m.~~8:00 p.m~~. on the following day, notify Must-Offer Generators of the ISO decisions on Waiver requests that were submitted to the ISO after 10:00 a.m.~~6:00 p.m~~. (beginning of Hour Ending 11~~9~~) on the day before; (3) end Waiver Denial Periods at any time; and (4) revoke Waivers at any time, while making best attempts to revoke a Waiver at least 90 minutes prior to time a unit would be required to be on-line generating at its Pmin.

5.11.6.1 Recovery of Minimum Load Costs By Must-Offer Generators

5.11.6.1.1 Eligibility

Units from Must-Offer Generators that incur Minimum Load Costs during Self-Commitment Periods or during hours for which the ISO has granted to them a waiver shall not be eligible to recover such costs for such hours. When a Must-Offer Generator ~~is awarded Ancillary Services in the Hour-Ahead Market or~~ has a Final Hour-Ahead Energy Schedule other than a Schedule to a unit-specific Demand ID used for the purpose of scheduling minimum load energy as set forth in Section 5.11.6, the Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on an hourly basis, a Must-Offer Generator generating at minimum load in compliance with the must-offer obligation, produces a quantity of Energy that varies by more than the greater of: (i) five (5) MWh or (ii) an hourly Energy amount equal to three (3) percent (%) of the unit's maximum operating output, the Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. Subject to the foregoing eligibility restrictions set forth in this section, the ISO shall pay to an otherwise eligible Must-Offer Generator the Minimum Load Costs for each hour within a Waiver Denial Period that the Generating Unit runs at minimum load in compliance with the must-offer obligation and for each hour that an otherwise eligible Must-Offer Generator generates in compliance with an ISO Dispatch Instruction.

5.11.6.1.2 Minimum Load Costs

The Minimum Load Costs shall be calculated as the sum, for all eligible hours in the Waiver Denial Period and Settlement Periods in which the unit generated in response to an ISO Dispatch Instruction, of: 1) the product of the unit's average heat rate (as determined by the ISO from the data provided in accordance with Section 2.5.23.3.3) at the unit's minimum operating level as set forth in Schedule 1 of the Generating Unit's Participating Generator Agreement and the gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or , if the Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas;~~the proxy figure for natural gas costs posted in the ISO Home Page in effect at the time and the unit's minimum operating level as set forth in Schedule 1 of the Generating Unit's Participating Generator Agreement~~ and 2) the product of the unit's minimum operating level as set forth in Schedule 1 of the Generating Unit's Participating Generator Agreement and $6.00/MWh.

5.11.6.1.2.1 Operating Must-Offer Generating Units above Minimum Load

If, during a Waiver Denial Period, the ISO requires that a Generating Unit operate at a level above its minimum load operating so as to be able to respond effectively to real time Dispatch Instructions, the ISO shall operate that Generating Unit at such an operating level. The ISO shall pay the Minimum Load Costs set forth in Section 5.11.6.1.2 for the amount of the Generating Unit's Minimum Load. For the amount of Energy above Minimum Load to the Unit's required operating level, the ISO shall pay the greater of the product of such amount of Energy and (1) the price for instructed Imbalance Energy or (2) the sum of (a) the product of (i) the Generating Unit's incremental heat rate at the required operating level and (ii) the proxy figure for natural gas costs set forth in Section 2.5.23.4, and (b) $6.00.

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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.

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5.11.6.2 Criteria for Issuing Must-Offer Waivers

The ISO shall grant waivers so as to: 1) provide sufficient on-line generating capacity to meet operating reserve requirements; and 2) account for other physical operating constraints, including Generating Unit minimum up and down times. The ISO shall grant, deny or revoke waivers using a security-constrained unit commitment software application to minimize start-up and Minimum Load Costs.

* * *

11.2.4.2 Payment Options for ISO Dispatch Orders

With respect to all resources which have not bid into the Imbalance Energy or Ancillary Services markets but which have been dispatched by the ISO to avoid an intervention in market operations, to prevent or relieve a System Emergency, or to satisfy a locational requirement, the ISO shall calculate, account for and, if applicable, settle deviations from the Final Schedule submitted on behalf of each such resource, with the relevant Scheduling Coordinator for each Settlement Period for each such resource by application of either of the following payment options described below. For resources subject to a Reliability Must-Run Contract, the ISO will dispatch such resources according to the terms of the RMR Contract, except as provided for below. In circumstances where an RMR Unit would be used to resolve Intra-Zonal Congestion and there are no such RMR Units available, a resource may be called upon and paid under this Section to resolve the Intra-Zonal Congestion.

By December 31 of each year for the following calendar year, each Scheduling Coordinator for a resource shall select one of the following payment options for each resource it schedules:

(a) the Uninstructed Imbalance Energy charge price as calculated in accordance with Section 2.5.23.2.2 (i.e., using the Hourly Ex Post Price) or

(b) a calculated price:

(i) for decremental dispatch orders that is an Energy payment to the ISO that is equal to the Market Clearing Price for the relevant Settlement Period for the applicable Energy market less verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's Dispatch Instruction and that the Scheduling Coordinator or Generator was not able to eliminate or reduce despite the application of best efforts, if the Scheduling Coordinator provides the resource's daily gas imbalance charges to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched; and

(ii) for incremental dispatch orders is the sum of: 1) a capacity payment equal to the average Day-Ahead Market prices for Spinning Reserve and Non-Spinning Reserve for the three (3) most recent similar days for the same Settlement Period for which the resource is dispatched; 2) an Energy payment equal to the average calculated using the ISO Real Time Market Energy prices for the three (3) most recent similar days for the same Settlement Period for which the resource is dispatched; 3) such resource's verifiable Start-Up ~~Fuel~~ Costs, if the start-up was solely attributable to the ISO's Dispatch Instruction and if the Scheduling Coordinator provides the resource's Start-Up ~~Fuel~~ Costs to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched; and 4) verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's Dispatch Instruction and that the Scheduling Coordinator or Generator was not able to eliminate or reduce despite the application of best efforts, if the Scheduling Coordinator provides the resource's daily gas imbalance charges to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched. References to "similar days" in this Section refer to Business Days when the resource is dispatched on a Business Day and otherwise to days that are not Business Days.

To the extent a Scheduling Coordinator does not specify a payment option, the ISO will apply the payment provisions of the payment option described in Section 11.2.4.2(a).

If the ISO Dispatches an RMR Unit that has selected Condition 2 of its RMR Contract to start-up or provide energy other than a start-up or energy requested pursuant to the RMR Contract, the ISO shall pay as follows:

1) if, as determined by the ISO, the sum of the service hours, service MWh or start-ups from service not under the RMR Contract and RMR Contract Counted Service Hours, Counted MWh, or Counted Start-ups does not exceed the applicable RMR Contract Service Limit, the ISO shall pay (a) for energy, the rate set forth in either Equation 1a or 1b below, as appropriate and (b) for a start-up, the rate specified in Schedule D to the applicable RMR Contract.

2) Equation 1a (for Units with input/output data in polynomial form) or Equation 1b (for Units with input/output data in exponential form) as defined below shall be used to calculate the Energy rate for MWh of Instructed Imbalance Energy delivered:

Equation 1a

$$\text{Energy Price (\$/MWh)} = \frac{(AX^3 + BX^2 + CX + D) * P * E}{X} + \text{Variable O\&M Rate}$$

Equation 1b

$$\text{Energy Price (\$/MWh)} = \frac{A * (B + CX + De^{FX}) * P * E}{X} + \text{Variable O\&M Rate}$$

Where:

- for Equation 1a, A, B, C, D and E are the coefficients given in Table C1-7a of the applicable RMR Contract;
- for Equation 1b, A, B, C, D, E and F are the coefficients given in Table C1-7b of the applicable RMR Contract;
- X is the Unit output level during the applicable settlement period, MWh;
- P is the Hourly Fuel Price as calculated by Equation C1-8 in Schedule C using the Commodity Prices in accordance with the applicable RMR Contract;
- Variable O&M Rate ($/MWh): as shown on Table C1-18 of the applicable RMR Contract.

3) If, as determined by the ISO, the sum of the service hours, service MWh or start-ups from service instructed by the ISO not under the RMR Contract and RMR Contract Counted Service Hours, Counted MWh, or Counted Start-ups, as applicable, exceeds the applicable RMR Contract Service Limit, the ISO shall pay:

a) if the Owner has elected Option A of Schedule G, two times the start-up cost specified in Schedule D to the applicable RMR Contract for any start-up incurred, and 1.5 times the rate specified in Equation 1a or 1b above times the amount of energy delivered in response to the ISO's instruction;

b) if the Owner has elected Option B of Schedule G, three times the start-up cost specified in Schedule D to the applicable RMR Contract for any start-up incurred, and the rate specified in Equation 1a or 1b above times the amount of energy delivered in response to the ISO's instruction.

~~4)~~If the ISO Dispatches an RMR Unit pursuant to the RMR Contract when the sum of the service hours, service MWh or start-ups from service not under the RMR Contract and the RMR Contract Counted Service Hours, Counted MWh or Counted Start-ups, as applicable, has exceeded the applicable RMR Contract Service Limit, the ISO shall pay the Scheduling Coordinator an additional amount so that the Scheduling Coordinator receives, in total, from the payment provided pursuant to the RMR Contract and the additional amount, the rates specified in Schedule G to the RMR Contract for the RMR Energy provided or for the RMR Start-Up Costs incurred until either the RMR Contract Counted MWh, Counted Service Hours or Counted Start-ups exceed the relevant RMR Contract Service Limit.

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11.2.4.2.1.1 Allocation of Costs from Out-Of-Market calls to Condition 2 RMR Units

All costs associated with energy provided by a Condition 2 RMR unit operating other than according to a dispatch notice issued under the RMR Contract shall be allocated in accordance with Section 11.2.4.2.1. Until either the RMR Contract Counted MWh, Counted Service Hours or Counted Start-ups exceed the relevant RMR Contract Service Limit, any cost incurred for energy provided under the RMR Contract above the rate specified in equation 1a or 1b as set forth in Section 11.2.4.2 shall be allocated in accordance with Section 11.2.4.2.1, not to the Responsible Utility.

Start-Up Costs for Condition 2 RMR Units providing service outside the RMR Contract, and any additional Start-Up Cost associated with a Condition 2 RMR Unit providing service under the RMR Contract when the unit's total service has exceeded an RMR Contract Service Limit but neither the RMR Contract Counted MWh, Counted Service Hours or Counted Start-ups have exceeded the applicable RMR Contract Service Limit, shall be invoiced in accordance with Section 2.5.23.3.7.6 and collected in accordance with Section 2.5.23.3.7.1.

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Reliability Services Costs	The costs associated with services provided by the ISO: 1) that are deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area; and 2) whose costs are billed by the ISO to the Participating TO pursuant to the ISO Tariff. Reliability Services Costs include costs charged by the ISO to a Participating TO associated with service provided under an RMR Contract (Section 5.2.8), local out-of-market dispatch calls (Section 11.2.4.2.1), and Minimum Load Costs associated with units committed under the must-offer obligation for local reliability requirements (Section 5.11.6.1.4).

* * *

Start-Up ~~Fuel~~ Cost Charge	The charge determined in accordance with Section 2.5.23.3.7.
Start-Up ~~Fuel~~ Cost Demand	The level of Demand specified in Section 2.5.23.3.7.3.
Start-Up ~~Fuel~~ Cost Invoice	The invoice submitted to the ISO in accordance with Section 2.5.23.3.7.6.
Start-Up ~~Fuel~~ Cost Trust Account	The trust account established in accordance with Section 2.5.23.3.7.2.

Start-Up ~~Fuel~~ Costs

The cost incurred ~~of the fuel consumed~~ by a particular Generating Unit from the time of first fire, the time of receipt of an ISO Dispatch instruction, or the time the unit was last synchornized to the grid, whichever is later, until the time the generating unit is synchronized or re-synchronized to the grid and producing Energy. Start-Up ~~Fuel~~ Costs are determined as the sum of (1) the cost of auxiliary power used during the start-up and (2) the number that is determined ~~by~~ multiplying the actual amount of fuel consumed by the proxy gas price as determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas~~in accordance with Section 2.5.23.3.4 at the time the fuel is consumed~~.

ATTACHMENT B2

2.5.21 Scheduling of Units to Provide Ancillary Services.

The ISO shall prepare supplier schedules for Ancillary Services (both self-provided and purchased by the ISO) for the Day-Ahead and the Hour-Ahead Markets. The ISO shall notify each Scheduling Coordinator no later than 1:00 p.m. of the day prior to the Trading Day of their Ancillary Services schedules for the Day-Ahead and no later than one hour prior to the operating hour of their Ancillary Services schedules for the Hour-Ahead. The ISO Protocols set forth the information, which will be included in these schedules. Where long-term contracts are involved, the information may be treated as standing information for the duration of the contract.

If, at any time after the issuance of Final Day-Ahead Schedules for the Trading Day and before the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day, the ISO determines that it requires Ancillary Services in addition to those included in the Final Day-Ahead Schedule (in the appropriate Zone if procuring zonally), the ISO may procure such additional Ancillary Services by providing Scheduling Coordinators with amended supplier schedules for the Day-Ahead Markets that include Ancillary Services for which previously submitted (but not selected) bids remain available and have not previously been withdrawn. The ISO shall select such Ancillary Services in price merit order (and in the relevant Zone if the ISO is procuring Ancillary Services on a Zonal basis). Such amended supplier schedules shall be provided to the Scheduling Coordinators no later than the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day.

Once the ISO has given Scheduling Coordinators notice of the Day-Ahead and Hour-Ahead Schedules, these schedules represent binding commitments made in the markets between the ISO and the Scheduling Coordinators concerned, subject to any amendments issued as described above. Any minimum energy input and output associated with Regulation and Spinning Reserve services shall be the responsibility of the Scheduling Coordinator, or provided in accordance with the must-offer obligation as set forth in Section 5.11, as the ISO's auction does not compensate the Scheduling Coordinator for the minimum energy output of Generating Units bidding to provide these

services. Accordingly, except as set forth under Section 5.11, the Scheduling Coordinators shall adjust their schedules to accommodate the minimum outputs required by the Generating Units to facilitate delivery of Energy from Ancillary Services~~included on the Schedules~~.

Notwithstanding the foregoing, a Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace that capacity in whole or in part from the ISO if the scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or if the Ancillary Service associated with a Generating Unit, Curtailable Demand, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduling Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replaced Ancillary Service shall be the Market Clearing Price in the Hour-Ahead Market for the Ancillary Service for the Settlement Period concerned for the Zone in which the Generating Units or other resources are located. The ISO will purchase the Ancillary Service concerned from another Scheduling Coordinator in the Hour-Ahead Market in accordance with the provisions of the ISO Tariff.

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2.5.23.3.7 Start-Up ~~Fuel~~ Costs

2.5.23.3.7.1 Obligation to Pay Start-Up ~~Fuel~~ Cost Charges

Each Scheduling Coordinator shall be obligated to pay a charge which will be used to pay the verified Start-Up ~~Fuel~~ Costs incurred by a Must-Offer Generator as a direct result of an ISO Dispatch instruction, in accordance with this Section 2.5.23.3.7. Such Start-Up Costs shall include (1) fuel and (2) auxiliary power. The ISO shall levy this charge (the "Start-Up ~~Fuel~~ Cost Charge"), each month, against all Scheduling Coordinators based upon each Scheduling Coordinator's Control Area Gross Load and Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area. Scheduling Coordinators shall make payment for all Start-Up ~~Fuel~~ Cost Charges in accordance with the ISO Payments Calendar.

2.5.23.3.7.2 Start-Up ~~Fuel~~ Cost Trust Account

All Start-Up ~~Fuel~~ Cost Charges received by the ISO shall be deposited in the Start-Up ~~Fuel~~ Cost Trust Account. The Start-Up ~~Fuel~~ Cost Trust Account shall be an interest-bearing account separate from all other accounts maintained by the ISO, and no other funds shall be commingled in it at any time.

2.5.23.3.7.3 Rate For the Start-Up ~~Fuel~~ Cost Charge

The rate at which the ISO will assess the Start-Up ~~Fuel~~ Cost Charge shall be at the projected annual total of all Start-Up ~~Fuel~~ Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instruction, adjusted for interest projected to be earned on the monies in the Start-Up ~~Fuel~~ Cost Trust Account, divided by the sum of the Control Area Gross Load and the projected Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area ("Start-Up ~~Fuel~~ Cost Demand"). The initial rate for the Start-Up ~~Fuel~~ Cost Charge, and all subsequent rates for the Start-Up ~~Fuel~~ Cost Charge, shall be posted on the ISO Home Page.

2.5.23.3.7.4 Adjustment of the Rate For the Start-Up ~~Fuel~~ Cost Charge

The ISO may adjust the rate at which the ISO will assess the Start-Up ~~Fuel~~ Cost Charge on a monthly basis, as necessary, to reflect the net effect of the following:

(a) the difference, if any, between actual Start-Up ~~Fuel~~ Cost Demand and projected Start-Up ~~Fuel~~ Cost Demand;

(b) the difference, if any, between the projections of the Start-Up ~~Fuel~~ Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instructions and the actual Start-Up ~~Fuel~~ Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instructions as invoiced to the ISO and verified in accordance with this Section 2.5.23.3.7; and

(c) the difference, if any, between actual and projected interest earned on funds in the Start-Up ~~Fuel~~ Cost Trust Account.

The adjusted rate at which the ISO will assess the Start-Up ~~Fuel~~ Cost Charge shall take effect on a prospective basis on the first day of the next calendar month. The ISO shall publish all data and calculations used by the ISO as a basis for such an adjustment on the ISO Home Page at least five (5) days in advance of the date on which the new rate shall go into effect.

2.5.23.3.7.5 Credits and Debits of Start-Up ~~Fuel~~ Cost Charges Collected from Scheduling Coordinators

In addition to the surcharges or credits permitted under Section 11.6.3.3 of this ISO Tariff, the ISO may credit or debit, as appropriate, the account of a Scheduling Coordinator for any over- or under-assessment of Start-Up ~~Fuel~~ Cost Charges that the ISO determines occurred due to the error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

2.5.23.3.7.6 Submission of Start-Up ~~Fuel~~ Cost Invoices

Scheduling Coordinators for Must-Offer Generators that incur Start-Up ~~Fuel~~ Costs as a direct result of an ISO Dispatch instruction or if the ISO revokes a waiver from compliance with the must-offer obligation while the unit is off-line in accordance with Section 5.11.6 of this ISO Tariff, and Scheduling Coordinators for Generating Units operating under Condition 2 of the relevant RMR Contract which are called out-of-market in accordance with Section 11.2.4.2 of this ISO Tariff or who are due an additional payment for a start-up under the RMR Contract in accordance with Section 11.2.4.2 of this ISO Tariff may submit to the ISO an invoice in the form specified on the ISO Home Page (the "Start-Up ~~Fuel~~ Cost Invoice") for the recovery of such Start-Up ~~Fuel~~ Costs. Such Start-Up ~~Fuel~~ Costs shall not exceed the costs which would be incurred within the start-up time for a unit specified in Schedule 1 of the Participating Generator Agreement. Start-Up ~~Fuel~~ Cost Invoices shall use the applicable proxy figure for natural gas costs as determined ~~in~~ by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas~~accordance with Section 2.5.23.3.4 and posted on the ISO Home Page~~. Start-Up Cost Invoices shall specify the amount of auxiliary power used during the start-up and the actual price paid for that power. Start-Up ~~Fuel~~ Cost Invoices shall not include any Start-Up ~~Fuel~~ Costs specified in an RMR Contract for a unit owned or controlled by a Must-Offer Generator.

2.5.23.3.7.7 Payment of Start-Up ~~Fuel~~ Cost Invoices

The ISO shall pay Scheduling Coordinators for all Start-Up ~~Fuel~~ Costs submitted in a Start-Up ~~Fuel~~ Cost Invoice and demonstrated to be a direct result of an ISO Dispatch instruction. The ISO shall pay such Start-Up ~~Fuel~~ Cost Invoices each month in accordance with the ISO Payments Calendar from the funds available in the Start-Up ~~Fuel~~ Cost Trust Account. To the extent there are insufficient funds available in the Start-Up ~~Fuel~~ Cost Trust Account in any month to pay all Start-Up ~~Fuel~~ Costs submitted in a Start-Up ~~Fuel~~ Cost Invoice and demonstrated to be a direct result of an ISO Dispatch instruction, the ISO shall make pro rata payment of such Start-Up ~~Fuel~~ Costs and shall adjust the rate at which the ISO will assess the Start-Up ~~Fuel~~ Cost Charge in accordance with Section 2.5.23.3.7.4. Any outstanding Start-Up ~~Fuel~~ Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay Start-Up ~~Fuel~~ Costs is limited to the obligation to pay Start-Up ~~Fuel~~ Cost Charges received. All disputes concerning payment of Start-Up ~~Fuel~~ Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.

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5.6 System Emergencies.

5.6.1 All Generating Units, System Units and System Resources that are owned or controlled by a Participating Generator are (without limitation to the ISO's other rights under this ISO Tariff) subject to control by the ISO during a System Emergency and in circumstances in which the ISO considers that a System Emergency is imminent or threatened. The ISO shall, subject to Section 5.6.2, have the authority to instruct a Participating Generator to bring its Generating Unit on-line, off-line, or increase or curtail the output of the Generating Unit and to alter scheduled deliveries of Energy and Ancillary Services into or out of the ISO Controlled Grid, if such an instruction is reasonably necessary to prevent an imminent or threatened System Emergency or to retain Operational Control over the ISO Controlled Grid during an actual System Emergency. <u>The ISO shall have the authority to instruct an RMR Unit whose owner has selected Condition 2 of its RMR Contract to start-up and change its output if the ISO has reasonably used all other available and effective resources to prevent a threatened System Emergency without declaring that a</u>

System Emergency exists. If the ISO so instructs a Condition 2 RMR Unit, it shall compensate that unit in accordance with Section 11.2.4.2 and allocate the costs in accordance with Section 11.2.4.2.1.1.

* * *

5.11.4 Obligation To Offer Available Capacity

Except as set forth in Section 5.11.6, aAll Must-Offer Generators shall offer to sell in the ISO's Real Time Market for Imbalance Energy, in all hours, all their Available Generation as defined in Section 5.11.2.

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5.11.6 ~~Waiver of~~ Must-Offer Obligation Process

Must-Offer Generators may seek a waiver of the obligation to offer all available capacity, as set forth in Section 5.11.4 of this ISO Tariff, for one or more of their Generating Units for periods other than Self-Commitment Periods.~~,~~ Self-Commitment Periods ~~which~~ are defined as the hours for which~~when~~ Must-Offer Generators submit Day-Ahead Energy Schedules~~ or are awarded Ancillary Services bids or self-provision schedules~~. Self-Commitment Periods determined from Day-Ahead Schedules shall be extended by the ISO as necessary to accommodate Generating Unit minimum up and down times such that the scheduled operation is feasible. All other Must-Offer Generators obligated under the must-offer obligation that have not submitted Day-Ahead Energy Schedules will be deemed to have requested a waiver, either implicitly or explicitly, of the obligation to offer all available capacity. If conditions permit, and at the ISO's non-discriminatory and sole discretion, the ISO may grant waivers and allow a Must-Offer Generator to remove one or more Generating Units from service~~ during hours outside Self-Commitment Periods~~. The Self-Commitment Period defined by a Generating Unit's Day-Ahead schedules (plus any additional time necessary to accommodate minimum up and minimum down times) shall remain in effect for that Generating Unit even if a Must-Offer Generator nullifies the Day-Ahead Schedules submitted for that unit in the Hour-Ahead Market. If a Must-Offer Generator requests a waiver for a Generating Unit for its Self-Commitment Period, the ISO may grant the waiver, but if the ISO denies the waiver, the unit shall not be eligible to recover Minimum Load Costs incurred during any Self-Commitment Period as set forth in Section 5.11.6.1.1.~~The ISO shall grant waivers so as to: 1) provide sufficient on-line generating capacity to meet Operating Reserve requirements; and 2) account for other physical operating constraints, including Generating Unit minimum up and down times.~~ The hours outside of Self-Commitment Periods for which waivers are not granted shall constitute Waiver Denial Periods. A~~The~~ Waiver Denial Period shall be extended as necessary to accommodate Generating Unit minimum up and down times. Units shall be on-line in real time during both Self-Commitment and Waiver Denial Periods, or they will be in violation of the must-offer obligation. Exceptions shall be allowed for verified forced outages. ~~The must-offer obligation will remain in effect for a unit's Self-Commitment Period even if the Must-Offer Generator nullifies its Day-Ahead Schedules for Energy or buys back its Day-Ahead Schedules for a unit in the Hour-Ahead Market.~~ The ISO may revoke waivers as necessary due to outages, changes in Load forecasts, or changes in system conditions. The ISO shall determine which waiver(s) will be revoked, and shall notify the relevant Scheduling Coordinator(s). The ISO shall inform a Must-Offer Generator that its Waiver request has been accepted, denied, or revoked, and shall provide the Must-Offer Generator with the reason(s) for the decision, which reasons shall be non-discriminatory. The ISO will: (1) notify Must-Offer Generators of the ISO decisions on pending Waiver requests received no later than 10:00 a.m.~~6:00 p.m.~~ (beginning of Hour Ending 11~~9~~) no later than 11:30 a.m.~~8:00 p.m.~~ (middle~~beginning~~ of Hour Ending 12~~21~~) on the day before the operating day for which the Waivers are requested; (2) at any time but no later than 11:30 a.m.~~8:00 p.m.~~ on the following day, notify Must-Offer Generators of the ISO decisions on Waiver requests that were submitted to the ISO after 10:00 a.m.~~6:00 p.m.~~ (beginning of Hour Ending 11~~9~~) on the day before; (3) end Waiver Denial Periods at any time; and (4) revoke Waivers at any time, while making best attempts to revoke a Waiver at least 90 minutes prior to time a unit would be required to be on-line generating at its Pmin.

5.11.6.1 Recovery of Minimum Load Costs By Must-Offer Generators

5.11.6.1.1 Eligibility

Units from Must-Offer Generators that incur Minimum Load Costs during Self-Commitment Periods or during hours for which the ISO has granted to them a waiver shall not be eligible to recover such costs for such hours. When a Must-Offer Generator ~~is awarded Ancillary Services in the Hour-Ahead Market or~~ has a Final Hour-Ahead Energy Schedule other than a Schedule to a unit-specific Demand ID used for the purpose of scheduling minimum load energy as set forth in Section 5.11.6, the Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on a 10-minute Settlement Interval basis, a Must-Offer Generator generating at minimum load in compliance with the must-offer obligation, produces a quantity of Energy that varies by more than the Tolerance Band, the Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such Settlement Intervals during hours within a Waiver Denial Period. When, on a Settlement Interval basis, a Must-Offer Generator's resource produces a quantity of Energy above minimum load due to an ISO Dispatch Instruction, the Must-Offer Generator shall recover its Minimum Load Costs and its bid costs, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band. Subject to the foregoing eligibility restrictions set forth in this section, the ISO shall guarantee recovery of the Minimum Load Costs of an otherwise eligible Must-Offer Generator for each Settlement Interval during hours within a Waiver Denial Period as follows: (1) First, ISO will pre-dispatch for real time the minimum load Energy from Must-Offer Generators that have been denied waivers for each hour within a Waiver Denial Period; (2) This minimum load Energy will be accounted as Instructed Imbalance Energy for each Settlement Interval within the relevant hour and be settled at the Resource-Specific Settlement Interval Ex Post Price; (3) To the extent the Instructed Imbalance Energy payments are not sufficient to cover the generator's Minimum Load Cost ~~for the hour~~ as defined in Section 5.11.6.1.2 of this Tariff, the generator will also receive an uplift payment for its Minimum Load Cost compensation for the relevant eligible Settlement Intervals of hours during the Waiver Denial Period that the Generating Unit runs at minimum load in compliance with the must-offer obligation; and (4) To the extent the Generator is dispatched for real time Imbalance Energy above its minimum load for any Dispatch Interval within an hour during the Waiver Denial Period, the Generator will be eligible for Bid Cost Recovery, as set forth in Section 11.2.4.1.1.1.

5.11.6.1.2 Minimum Load Costs

The Minimum Load Costs shall be calculated as the sum, for all eligible hours in the Waiver Denial Period and Settlement Periods in which the unit generated in response to an ISO Dispatch Instruction, of: 1) the product of the unit's average heat rate (as determined by the ISO from the data provided in accordance with Section 2.5.23.3.3) at the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in Schedule A to the resource's Reliability Must-Run Contract if the resource is subject to a Reliability Must-Run Contract, or, if the resource is not subject to a Reliability Must-Run Contract or has so directed in Schedule A to its Reliability Must-Run Contract, the ISO Master File as amended through notification to the ISO via SLIC and the gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas ~~the proxy figure for natural gas costs posted in the ISO Home Page in effect at the time and the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC~~; and 2) the product of the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC; and $6.00/MWh.

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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~~d~~ 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 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.

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5.11.6.2 Criteria for Issuing Must-Offer Waivers

The ISO shall grant waivers so as to: 1) provide sufficient on-line generating capacity to meet operating requirements; and 2) account for other physical operating constraints, including Generating Unit minimum up and down times. The ISO shall grant, deny or revoke waivers using a security-constrained unit commitment software application to minimize start-up and Minimum Load Costs.

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11.2.4.2 Payment Options for ISO Dispatch Orders

With respect to all resources which have not bid into the Imbalance Energy or Ancillary Services markets but which have been dispatched by the ISO to avoid an intervention in market operations, to prevent or relieve a System Emergency, or to satisfy a locational requirement, the ISO shall calculate, account for and, if applicable, settle deviations from the Final Schedule submitted on behalf of each such resource, with the relevant Scheduling Coordinator for each Settlement Period for each such resource by application of either of the following payment options described below. For resources subject to a Reliability Must-Run Contract, the ISO will dispatch such resources according to the terms of the RMR Contract, except as provided for below. In circumstances where an RMR Unit would be used to resolve Intra-Zonal Congestion and there are no such RMR Units available, a resource may be called upon and paid under this Section to resolve the Intra-Zonal Congestion.

By December 31 of each year for the following calendar year, each Scheduling Coordinator for a resource shall select one of the following payment options for each resource it schedules:

(a) the Uninstructed Imbalance Energy charge price as calculated in accordance with Section 2.5.23.2.2 (i.e., using the Hourly Ex Post Price) or

(b) a calculated price:

(i) for decremental dispatch orders that is an Energy payment to the ISO that is equal to the Market Clearing Price for the relevant Settlement Period for the applicable Energy market less verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's Dispatch Instruction and that the Scheduling Coordinator or Generator was not able to eliminate or reduce despite the application of best efforts, if the Scheduling Coordinator provides the resource's daily gas imbalance charges to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched; and

(ii) for incremental dispatch orders is the sum of: 1) a capacity payment equal to the average Day-Ahead Market prices for Spinning Reserve and Non-Spinning Reserve for the three (3) most recent similar days for the same Settlement Period for which the resource is dispatched; 2) an Energy payment equal to the average calculated using the ISO Real Time Market Energy prices for the three (3) most recent similar days for the same Settlement Period for which the resource is dispatched; 3) such resource's verifiable Start-Up ~~Fuel~~ Costs, if the start-up was solely attributable to the ISO's Dispatch Instruction and if the Scheduling Coordinator provides the resource's Start-Up ~~Fuel~~ Costs to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched; and 4) verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's Dispatch Instruction and that the Scheduling Coordinator or Generator was not able to eliminate or reduce despite the application of best efforts, if the Scheduling

Coordinator provides the resource's daily gas imbalance charges to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched. References to "similar days" in this Section refer to Business Days when the resource is dispatched on a Business Day and otherwise to days that are not Business Days.

To the extent a Scheduling Coordinator does not specify a payment option, the ISO will apply the payment provisions of the payment option described in Section 11.2.4.2(a).

If the ISO Dispatches an RMR Unit that has selected Condition 2 of its RMR Contract to start-up or provide energy other than a start-up or energy requested pursuant to the RMR Contract, the ISO shall pay as follows:

1) if, as determined by the ISO, the sum of the service hours, service MWh or start-ups from service not under the RMR Contract and RMR Contract Counted Service Hours, Counted MWh, or Counted Start-ups does not exceed the applicable RMR Contract Service Limit (as those terms are defined in the RMR Contract), the ISO shall pay (a) for energy, the rate set forth in either Equation 1a or 1b below, as appropriate and (b) for a start-up, the rate specified in Schedule D to the applicable RMR Contract.

2) Equation 1a (for Units with input/output data in polynomial form) or Equation 1b (for Units with input/output data in exponential form) as defined below shall be used to calculate the Energy rate for MWh of Instructed Imbalance Energy delivered:

Equation 1a

$$\text{Energy Price (\$/MWh)} = \frac{(AX^3 + BX^2 + CX + D) * P * E}{X} + \text{Variable O\&M Rate}$$

Equation 1b

$$\text{Energy Price (\$/MWh)} = \frac{A * (B + CX + De^{FX}) * P * E}{X} + \text{Variable O\&M Rate}$$

Where:

- for Equation 1a, A, B, C, D and E are the coefficients given in Table C1-7a of the applicable RMR Contract;
- for Equation 1b, A, B, C, D, E and F are the coefficients given in Table C1-7b of the applicable RMR Contract;

- X is the Unit output level during the applicable settlement period, MWh;
- P is the Hourly Fuel Price as calculated by Equation C1-8 in Schedule C using the Commodity Prices in accordance with the applicable RMR Contract;
- Variable O&M Rate ($/MWh): as shown on Table C1-18 of the applicable RMR Contract.

3) If, as determined by the ISO, the sum of the service hours, service MWh or start-ups from service instructed by the ISO not under the RMR Contract and RMR Contract Counted Service Hours, Counted MWh, or Counted Start-ups, as applicable, exceeds the applicable RMR Contract Service Limit, the ISO shall pay:

   a) if the Owner has elected Option A of Schedule G, two times the start-up cost specified in Schedule D to the applicable RMR Contract for any start-up incurred, and 1.5 times the rate specified in Equation 1a or 1b above times the amount of energy delivered in response to the ISO's instruction;

   b) if the Owner has elected Option B of Schedule G, three times the start-up cost specified in Schedule D to the applicable RMR Contract for any start-up incurred, and the rate specified in Equation 1a or 1b above times the amount of energy delivered in response to the ISO's instruction.

If the ISO Dispatches an RMR Unit pursuant to the RMR Contract when the sum of the service hours, service MWh or start-ups from service not under the RMR Contract and the RMR Contract Counted Service Hours, Counted MWh or Counted Start-ups, as applicable, has exceeded the applicable RMR Contract Service Limit, the ISO shall pay the Scheduling Coordinator an additional amount so that the Scheduling Coordinator receives, in total, from the payment provided pursuant to the RMR Contract and the additional amount, the rates specified in Schedule G to the RMR Contract for the RMR Energy provided or for the RMR Start-Up Costs incurred until either the RMR Counted MWh, Counted Service Hours or Counted Start-ups exceed the relevant RMR Contract Service Limit.

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11.2.4.2.1.1 Allocation of Costs from Out-Of-Market calls to Condition 2 RMR Units

All costs associated with energy provided by a Condition 2 RMR unit operating other than according to a dispatch notice issued under the RMR Contract shall be allocated in accordance with Section 11.2.4.2.1. Until either the RMR Contract Counted MWh, Counted Service Hours or Counted Start-ups exceed the relevant RMR Contract Service Limit, any cost incurred for energy provided under the RMR Contract above the rate specified in equation 1a or 1b as set forth in Section 11.2.4.2 shall be allocated in accordance with Section 11.2.4.2.1, not to the Responsible Utility.

Start-Up Costs for Condition 2 RMR Units providing service outside the RMR Contract, and any additional Start-Up Cost associated with a Condition 2 RMR Unit providing service under the RMR Contract when the unit's total service has exceeded an RMR Contract Service Limit but neither the RMR Contract Counted MWh, Counted Service Hours or Counted Start-ups have exceeded the applicable RMR Contract Service Limit, shall be invoiced in accordance with Section 2.5.23.3.7.6 and collected in accordance with Section 2.5.23.3.7.1.

* * *

Reliability Services Costs	The costs associated with services provided by the ISO: 1) that are deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area; and 2) whose costs are billed by the ISO to the Participating TO pursuant to the ISO Tariff. Reliability Services Costs include costs charged by the ISO to a Participating TO associated with service provided under an RMR Contract (Section 5.2.8), local out-of-market dispatch calls (Section 11.2.4.2.1), and Minimum Load Costs associated with units committed under the must-offer obligation for local reliability requirements (Section 5.11.6.1.4).

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Start-Up ~~Fuel~~ Cost Charge	The charge determined in accordance with Section 2.5.23.3.7.

Start-Up ~~Fuel~~ Cost Demand	The level of Demand specified in Section 2.5.23.3.7.3.
Start-Up ~~Fuel~~ Cost Invoice	The invoice submitted to the ISO in accordance with Section 2.5.23.3.7.6.
Start-Up ~~Fuel~~ Cost Trust Account	The trust account established in accordance with Section 2.5.23.3.7.2.
Start-Up ~~Fuel~~ Costs	The cost incurred~~of the fuel consumed~~ by a particular Generating Unit from the time of first fire, the time of receipt of an ISO Dispatch instruction, or the time the unit was last synchronized to the grid, whichever is later, until the time the generating unit is synchronized or re-synchronized to the grid and producing Energy. Start-Up ~~Fuel~~ Costs are determined as the sum of ~~by~~ (1) the cost of auxiliary power used during the start-up and (2) the number that is determined multiplying the actual amount of fuel consumed by the proxy gas price as determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas~~in accordance with Section 2.5.23.3.4 at the time the fuel is consumed~~.

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					compensation flow (some paying, some receiving).	and market participants to meet these needs through market mechanisms, thereby reducing, if not eliminating, the need for waiver denial. In addition, operational audits should be performed by an independent third-party to ensure that the capacity procurement process continues to operate correctly.		
Compensation	How should units committed under the Must-Offer Obligation be compensated? What costs should be paid?	The ISO believes the following constitutes the right compensation: 1. A Must-Offer unit should be paid its start-up cost if it is started up at the direction of the ISO. 2. As provided for under Phase 1B, a Must-Offer unit should be paid the greater of the imbalance energy price or its costs for minimum load energy not paid for through a bilateral agreement when operating in accordance with the must-offer obligation. 3. A Must-Offer unit should be paid minimum load costs in those intervals in which 1) they are	To prevent any misuse of Must Offer to manipulate prices, Must Offer compensation must be set properly. The CAISO benefits from Must Offer by reducing its spot market price risk. This reduced risk, as well as other benefits, should be compensated with a capacity reservation payment for all available capacity as well as an energy payment for minimum load (Minimum Load Cost payment). It is appropriate to include compensation for intra-state gas transportation, auxiliary power, and muni use fees in start-up and minimum load costs.	Units should be compensated for the market service they are providing. If the CAISO has published a "reliability need" and it doesn't find merit in signing an RMR contract than the service procured should be through a market mechanism. The CAISO has inherently recognized that there is a value for the capacity procured through the Must-Offer and that capacity should be compensated at a fair market value.	Must Offer does not represent a product secured by the ISO. Suppliers complying with a must offer obligation are not hindered in any way from selling energy or capacity from their units, either forward or in the Day Ahead or Hour Ahead time frames. Must offer does not diminish any value realizable by the supplier; it does not represent a product. As Must-Offer is a FERC-regulated, cost-of-service procedure, compensation should cover all bonafide costs to stay on, consistent with FERC order. No new capacity payments	**On March 25, 2004, the CAISO Board resolved:** **"2) Use the gas price formula specified in the RMR Contract (including volumetric intra-state gas transportation charges and municipal use fees), including the 2% adder, for calculating Minimum Load Cost Compensation and Start-Up Fuel Cost;** **3) Permit the Must-Offer Generator to include the cost of auxiliary power in the cost of starting up a unit to comply with the Must-Offer obligation;** **4) Provide for a three-tiered recovery of Minimum Load Cost Compensation costs**	MO compensation should cover all bonafide costs resulting from arms length transactions associated with compiling with CAISO MO instructions. No new capacity payments are warranted for Must Offer units denied waivers since units would have every opportunity to make market based sales prior to a MO commitment. However, for administrative reasons, verification of all actual costs my not be practicable. Thus SCE is open to the use of indices which are transparent and based on a liquid market. Bid-week indices will be the most robust in this	As explained in the first question, RMR CII units should receive the higher of an adopted scarcity price or its RMR contract Schedule G rate. In its October 28, 2003 Order on CAISO's market redesign, the FERC recognized the legitimacy of a bid-based availability payment for reliability resources. Since that time, the importance of a capacity payment by CAISO has only increased in light of the CPUC's decision to not set any firm RAR before January 1, 2008 (Decision 04-01-050, January 22, 2004)

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		dispatched by the ISO to provide imbalance energy; 2) they provide Ancillary Services capacity; 3) do not have a bilateral transaction; 4) if operating at minimum load, or returning to minimum load from a prior ISO dispatch instruction (not from a prior bilateral transaction), are operating within the Tolerance Band amount of the unit's minimum load level after accounting for any residual energy. 4. The ISO supports paying minimum load costs for units providing Ancillary Services (but not engaged in any other bilateral transaction). 5. The ISO does not believe that a Must-Offer unit should be paid a capacity payment for the capacity provided under the Must-Offer obligation. 6. Because a must-offer unit committed through the waiver process would have been shut down absent the ISO's directive that it remain in operation, there is	Must Offer imposes costs greater than variable costs on a generator unit. For example, the Must Offer obligation increases general wear and tear on a unit and increases unit cycling. This further results in increases in warranty and maintenance costs, thereby generally increasing a unit's fixed costs. Moreover, a unit may incur opportunity costs from operating on future days. In addition, not all units are staffed seven days a week for 24 hours a day. A Must Offer obligation can impose the hiring of additional staff at significant cost. Units must be compensated at the day-ahead price for gas when dispatched on or before 6 a.m. on the prior operating day. Units should be compensated based on daily spot indices when dispatched on or before 3 p.m. of the prior operating day. Units dispatched after 3 p.m. on the prior day should be compensated based on daily spot indices plus an adder for any	At a minimum, the unit should be able to collect its variable costs as well as a contribution to fixed costs. The Commission should consider the compromised proposal from the CAISO presented at the March 3-5, 2004 Technical conference on Residual Unit Commitment. Pending the implementation of a RAR or RUC this approach seems a reasonable compromise to consider on the interim.	are warranted for Must Offer units denied waivers, because, as stated above, there is no 'lost value' that must be uplifted to the supplier. It would be appropriate to include intra-state gas transportation, muni use fee and aux power costs in MLCC, as long as all Must-Offer compensation is specifically cost-based and there is no double-payment compensation. Additionally, consistent with the FERC order, all bonafide costs incurred to stay on should be compensated.	**based on whether the generating unit was committed for local reliability, zonal needs or system needs;** **5) Eliminate rescinding Minimum Load Cost Compensation when a unit subject to the Must-Offer obligation provides Ancillary Services but has no bilateral forward energy schedule and change the timing of the waiver process to allow bidding into the Day-Ahead market;"** RELIANT'S COMMENTS: For now, and until the CAISO implements a properly designed and functioning Resource Adequacy process, the compensation for Must-Offer units should be designed in a way that assures recovery of variable costs as well as making a contribution to fixed cost recovery. Reliant recognizes the fact that the CAISO Board recently voted to modify	aspect, but it may be appropriate to consider a liquid daily gas index. In any case, the double payment for energy must first be eliminated before any additional forms of payments are made.	Owners of units required for local reliability should enter into local reliability contracts with the CAISO. In such instances, payment for capacity and associated energy would be governed by the local reliability contract. Units needed for local reliability without a contract should receive a daily price that reflects local scarcity value. CAISO should adopt on an accelerated basis a RUC mechanism with a bid-based availability payment. Pending implementation of RUC, units committed via waiver denial should receive a capacity payment that provides a contribution to fixed costs. Pending implementation of a capacity payment mechanism, must-offer resources should receive a proxy capacity payment based on the instructed energy price. Payment for startup and minimum load costs (MLC) must track cost incurrence. Current RMR contract formulas represent a better starting point that the

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Category	New Question(s)	CAISO	Calpine Corporation	Independent Energy Producers Association	PG&E	Reliant	SCE	West Coast Power (WCP)
		no opportunity cost for that unit. 7. If a capacity payment is directed, it should be expressly treated as and labeled a capacity payment and not be an energy payment referred to as a surrogate capacity payment. The amount of that capacity payment should be set recognizing it will become an opportunity cost in the existing Ancillary Services markets and therefore will impose both direct (the capacity payment) and indirect costs (potentially increased Ancillary Services capacity prices to reflect the opportunity cost of providing "Must-Offer capacity") to market participants. 8. The ISO strongly believes that the existing double-payment for minimum load energy (MLCC plus the uninstructed imbalance energy price) must be eliminated as approved by the Commission for Phase 1B. Generators have	penalties/added charges.			certain portions of its must-offer compensation, but still feels that additional changes are warranted. **NON-RMR UNITS SHOULD NOT BE COMPENSATED AS IF THEY WERE RMR UNITS AND THERE SHOULD BE MEANINGFUL CORRELATION BETWEEN GAS INDICES AND DAILY FUEL COSTS OF NON-RMR MUST-OFFER GENERATING UNITS** Reliant appreciates the CAISO's March 25, 2004 board decision supporting the proposed inclusion of additional must-offer cost compensation components arising from intrastate gas transportation, municipal use fees and auxiliary power costs. In addition, Reliant believes that		current must-offer startup and MLC formulas. CAISO's payments for startup and MLC costs should include: 1. auxiliary power and startup fuel costs, 2. natural gas prices based upon a daily index price at a location relevant to where the generator buys its gas, 3. an allowance for gas imbalance charges, 4. local distribution company (LDC) transport fees and other variable or demand-related LDC tariff charges including municipal use fees and Gas Industry Restructuring (GIR) costs, 5. an O&M fee, 6. an emission cost fee, and 7. any variable or demand-related CAISO GMC fees. Regarding the issue of daily versus monthly indices, WCP emphasizes that it is not possible for a generator hedge the cost of gas to supply a daily must-offer call at a month-ahead

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		opportunities to recover fixed costs through participation in the imbalance energy market at market-based rates. The ISO recommends the following modifications to start-up and minimum load costs: 1. Start-up costs shall include auxiliary power costs. 2. The ISO shall use the method set forth in Schedule C of the RMR Contract to determine the relevant gas price. (Two-day average of daily indices at regional delivery points, plus intra-state transportation charges) 3. This assumes that no fuel costs or auxiliary power costs are included in the $6.00/MWh adder.				the CAISO's proposed use of regional gas prices is appropriate to calculate start-up and minimum load costs (i.e., "Minimum Load Compensation Costs" or "MLCC"). However, Reliant believes that the CAISO's proposed calculation of daily minimum load and start-up costs using a two-day average of regional daily gas indices, like RMR contracts, is inappropriate. Unlike RMR contracts, the must-offer process is not conducted at arms length. Rather, the must-offer is imposed on the owner of the generating unit that is denied a must-offer waiver request. That is, the owner of the must-offer generating unit is told when it is to operate under the must-offer procedure without valuable consideration for the other components of its costs, as is the		gas price. The index used in MLC calculations should accurately track the cost of gas procured when CAISO makes a capacity call; i.e., a day ahead market index. WCP is encouraged with CAISO staff's consideration of methods wherein cost computation would more closely follow methods currently in use in the RMR contracts.

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						case for RMR-contracted generating units. Certain components cannot be extracted from the RMR contracts in isolation and assumed adequate for purposes of compensating non-RMR generating units subject to the must-offer procedure. More importantly, however, use of the two-day average gas price to calculate daily start-up and minimum load costs results in must-offer compensation that is based on gas prices over a period that is different than that of the daily must-offer delivery period. Such an approach will provide no meaningful correlation of indices and the costs actually incurred by non-RMR must-offer generating units. The gas index used for compensating non-RMR must-offer generating units should reflect the appropriate regional		

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						daily gas indices for the same day(s) as the must-offer delivery period. In addition, Reliant appreciates the CAISO's continued inclusion of the \$6/MWh payment and uninstructed imbalance energy payment in its must-offer compensation. The imbalance energy payment helps makes an important contribution towards covering generators full costs of operation. As a threshold matter, if the CAISO reduces the Must-Offer compensation as described in FERC Docket No. ER03-1046-000, then the generator's revenue is less likely to cover the generator's cash costs. When compensation is below, and expected to remain below, the cash costs to run a unit, it is likely that affected generating units will exit the		

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						market due to economic reasons Despite the additional proposed must-offer compensation components that were approved by the board, Reliant still believes that both the current and proposed must-offer compensation are deficient because they fail to make provision for cost recovery of costs associated with emissions or other administratively determined costs that are potentially allocable to electric generators. Specifically, must offer compensation should be revised to include emissions costs by applying the emissions rate to the emissions allowance price based on recent transactions (that accurately reflect the value of allowances or on values most recently published by		

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						a recognized allowance broker or brokers), and any administratively determined costs allocated to electric generators (for example, surcharges or fees related to Gas Industry Restructuring (GIR) costs, strategic gas storage development or supplemental non-core interstate capacity costs). **LR PARTICIPATION IN CAISO'S A/S MARKETS WITHOUT CHANGING MARKET PROCESSES OR TIMELINES** Under Reliant's proposal, described in the section herein entitled "Must-Offer Mechanics" in which local reliability ("LR") resources are evaluated and identified for commitment/dispatch at the same time of the day by CAISO personnel as RMR		

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						units, there is no need for the CAISO to modify its Day-Ahead processes or timelines to accommodate must-offer resources' participation in the CAISO's Ancillary Services ("A/S") management process. The LR resources, designated for commitment/dispatch ahead of the CAISO's Day-Ahead process, would be free to offer into the Day-Ahead market for A/S capacity. If selected (and to be paid for the A/S capacity awarded), the LR resource(s) would be on the same footing as all other resources offering into and being awarded A/S capacity. Under Reliant's proposed approach, the CAISO would not have to pay those awarded Ancillary Service capacity for MLCC since the owners of LR resources would		

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						have already priced their start-up, minimum run and other costs into their capacity price offers (just as all other competitors are expected to do under the CAISO's existing A/S tariff provisions). If the LR resource is not selected in the CAISO's Day-Ahead A/S market then the MLCC is not rescinded in accordance with the related aspects of the CAISO's must-offer proposal. The key, however, is to assure that the CAISO has the opportunity to address its local reliability requirements for non-RMR units on the same timeframe as its other local reliability requirements with contracted RMR units. This approach will deepen the participation in the CAISO's A/S markets and provide for the streamlined financial settlement of must-		

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						offer costs on a system-wide basis (i.e., since the costs of LR, like RMR, would be incurred to satisfy the CAISO's local reliability needs and allocated accordingly). Again, Reliant believes that its proposal will complement the CAISO's must-offer proposal by clearly delineating local reliability costs, incurred by non-market RMR and LR resources, from system-wide costs incurred by market resources. **RELIANT'S PROPOSAL OBVIATES THE NEED TO ADD UNNECESSARY COMPLEXITY TO THE CAISO TARIFF TO ALLOCATE NON-MARKET COSTS ON LOCAL, ZONAL AND SYSTEM-WIDE BASES** Again, under Reliant's approach that		

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						complements the CAISO's must-offer proposal, as described in the section herein entitled "Must-Offer Mechanics" in which local reliability ("LR") resources are evaluated and identified for non-market commitment and dispatch at the same time of the day as RMR units by CAISO personnel, a clear delineation of non-market local reliability costs will be accounted separately from all other zonal and control area-related requirements that are arranged under existing tariff provisions. Moreover, those market resources that are available to resolve zonal and/or system-wide requirements should be committed, dispatched and financially settled on a market basis in accordance with existing CAISO tariff provisions. To do		

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						otherwise will only serve to unnecessarily complicate the CAISO's already complex tariff provisions relating to commitment, dispatch and financial settlements of local, zonal and system-wide services. In sum, and as the design-basis for Reliant's proposed approach that complements the relevant parts of the CAISO's must-offer proposal, non-market RMR and LR resources should be committed, dispatched and financially settled, with associated costs allocated accordingly, without unnecessarily and inappropriately commingling the use of market resources that should be put to the purposes of addressing the CAISO's zonal and system-wide requirements in accordance with existing CAISO tariff		

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						provisions. .		
Cost Allocation	How should Must-Offer costs be allocated?	Start-up costs should continue to be allocated to all ISO metered Demand plus exports on a monthly MWh basis. The cost of Must-Offer units committed to meet local reliability needs should be allocated to the Participating Transmission Owner in whose service area the unit was located or whose transmission system required the unit to be committed. The cost of Must-Offer units committed due to inter-zonal congestion should be allocated to metered Demand and exports in the congested zone. Otherwise, the cost of Must-Offer units committed should be allocated in proportion to the positive difference between a Scheduling Coordinator's metered Demand and their scheduled Demand, up	Costs should be allocated consistent with the cost-causation principle to ensure that both LSEs and generators receive the proper price signals.	The CAISO proposal for cost-allocation is preferable over the current methodology. Costs should follow the cost/causation principle as required by federal and state law. Currently the CAISO's misuse of the Must-Offer process distorts price signals to both generators and utilities. In particular, utilities have no incentive to procure sufficient capacity and energy to meet local reliability needs. Within the Must-Offer context this is of particular importance in that the Customers of Southern California were successful in eliminating close to all of their RMR contracts. However the CAISO appears to	Except when Must-Offer is solely used to meet local reliability concerns, the cost should be allocated to all load using the ISO System, as is currently done with energy and ancillary services costs. Must-Offer costs incurred to meet local reliability concerns should be assigned to load within the zone in which the reliability concern was located.	RELIANT'S COMMENTS: Reliant believes that costs should be allocated based on the FERC cost-causation principle. RMR contracts, and associated Designation Criteria, should be focused on maintaining the availability of uneconomic resources for local reliability needs that would otherwise shut down in the absence of an RMR contract. LR units, under Reliant's proposal (described in the answer herein to "Must Offer Mechanics"), should be focused on mitigating local market power when local reliability needs require generation when a competitive	MO costs incurred for system needs should be spread to scheduling deficient SCs before spreading across all loads.	

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		to a capped rate determined by dividing the minimum load costs by the minimum load MWh in that hour. Costs above this capped rate should be allocated to all Scheduling Coordinators in proportion to their metered Demand. Per FERC's directive, "metered" Demand in this context means Demand in the ISO Control Area plus exports to Demand within California.		be utilizing the Must-Offer process in Southern California as a surrogate for an RMR contract. If the costs for Must-Offer were allocated in a similar fashion to the RMR than there would be a cost-causation for the LRN. They are not. In fact the CAISO procures <95% of the Must-Offer in SP15 and ALL load and exports bear the cost equally. While the commitment methodologies and procedures should be clear, the CAISO should not allow a specific market participant who stands to benefit by altering the proposed cost allocation methodology, to modify or delay the implementation of this new cost-allocation proposal.		solution does not exist. As such, and for now, RMR and LR costs should be allocated locally, whereas the costs of Must-Offer generation should be allocated to all load serving entities on a load ratio share basis.		

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RMR Condition 2	Should RMR Condition II units be used for purposes other than local reliability? If so, under what conditions?	Yes. Condition 2 Units should be used for purposes other than local reliability under the following conditions: Under the following conditions: • If a Condition 2 RMR unit is subject to "hard" (i.e., environmental) annual operating limits, the unit would not be subject to the Must-Offer obligation if the service it provides under the Must-Offer obligation could jeopardize the unit's ability to provide local reliability service. • If a Condition 2 RMR unit is <u>not</u> subject to "hard" (i.e., environmental) annual operating limits, the unit would be subject to the Must-Offer obligation and committed based on its costs after all other effective non-Condition 2 units had been committed. • Any service provided pursuant to the Must-Offer	No. RMR Condition II units are not physically withholding capacity from the market as evidenced by the terms and conditions of the RMR contract. Any commitment and dispatch of an RMR unit must be done in accordance with the terms and conditions of its RMR contract.	<u>**General Comments:**</u> IEP appreciates the modifications made by the CAISO to the Must-Offer Process (MOP). While the CAISO has made many modifications to the MOP the fundamental issue surrounding how capacity from MO units are compensated has yet to be determined IEP would like to point out that while there are many unresolved issues, the CAISO has resolved many of the smaller issues and has facilitated (under Brian Theaker's leadership) a well reasoned stakeholder process; a process that has been sorely missed in recent years. Fundamentally there is continued disagreement regarding what "Must Offer" should be used for. It is IEP understands that the Commission implemented the	RMR Condition II units should be subject to the Must-Offer requirement, and used in the same manner as other generating units that are subject to the Must-Offer requirement are used. However they should be used only when alternative market supply bids have been exhausted.	**On March 25, 2004, the CAISO Board resolved:** **"6) Implement the following method for compensating RMR Condition 2 Units for non-RMR service:** **a. Pay for any non-RMR service provided by Condition 2 RMR units at the RMR Contract price until the combined non-RMR and RMR service exceeds the RMR Contract Service Limits;** **b. Pay for all subsequent RMR and non-RMR service at the applicable Schedule G price;** **c. Allocate the incremental cost for RMR service (the Schedule G cost above the cost otherwise specified in the RMR Contract) to the market per the current mechanism for allocating OOM costs until RMR service alone exceeds the Contract Service Limits; and** **d. Allocate the costs of any non-RMR service to the market per the current method for allocating OOM costs."**	Units under the current RMR Condition II contracts should only be dispatched under the terms and conditions of these contracts. Dispatching RMR Condition II units for reasons other than those in the contract (e.g. MO obligation to meet a non-local need) is fundamentally inconsistent with the reason why the unit is under an RMR Condition II contract. Lastly, since MO should not be used as a product substitute for RMR during normal operating conditions, there is no need to reevaluate RMR designation criteria as a result of the use of MO.	West Coast Power ("WCP") is a partnership of Dynegy, Inc. and NRG Energy, Inc. WCP owns and operates over 2,300 MW of formerly utility-owned generation resources in the SP15 zone. WCP resources are regularly denied must-offer waivers and thus are called upon day-ahead or day-of to operate at minimum load pursuant to the current must-offer requirement. WCP wishes to convey to FERC staff, the CAISO, and other stakeholders that the benefits of a competitive power sector will be realized only if a market climate is created that continues to attract capital. The collective set of markets--bilateral contracts, reliability must-run (RMR) contracts, forward energy and ancillary-services (AS) markets, residual unit commitment (RUC), and real-time (RT) energy--must provide sufficient revenue to cover the going-forward costs of existing generation, including return of and on capital, and be

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		obligation would not count towards the annual service under the RMR contract. Similarly, any service provided under the Must-Offer obligation would not be included in determining next year's service limits. • When the combined RMR and non-RMR service has reached the contract annual service limit, the RMR Owner may reflect the elected Schedule G multiplier in its minimum load costs and in its energy bid price. • When operating under the must-offer obligation, a Condition 2 unit will bid into the ISO's markets at the Schedule M rates. • Because the Participating Transmission Owner is paying the unit's full fixed costs, all profits from sales in the ISO's markets will credit to the PTO, up to the unit's full fixed costs. The		Must-Offer Obligation to prevent physical withholding. The Commission should however be aware of the systemic abuse of the Must-Offer obligation within the CAISO markets that will likely become exacerbated further when the CAISO moves to regional procurement of Ancillary Services (June 2004). The continuation of the current unit commitment process through must offer is just an additional crutch utilized by LSE's in order to further delay a viable Resource Adequacy Requirement in California. Reliance on this crutch could further exacerbate the resource challenges facing California. The Commission should not be misled to believe that the two are not intrinsically linked. **<u>RMR/Condition II Process:</u>**		RELIANT'S COMMENTS: Reliant does not support continuing the current waiver denial process and proposes (in the answer nerein to "Must Offer Mechanics") a procedure that complements the CAISO's TCUC analysis to minimize CAISO's reliance on capacity acquired by means of must-offer waiver denials. The CAISO should <u>commit</u> Condition 2 units only for local reliability needs. Utilization of RMR units for purposes other than local reliability precludes level-playing field competition between RMR and non-RMR market units, and ultimately leads to market failures and further reliability problems. This is because RMR condition 2 units are paid under an administratively determined price to meet local reliability needs, while market units are paid market prices. Under Reliant's proposed mechanics,		sufficient to attract investment new generation in the areas where resources are needed. **The current method of committing (via waiver denials) and compensating resources pursuant to must offer, combined with the absence of a resource adequacy requirement (RAR), has effectively eliminated any viable market for capacity within the CAISO-controlled grid. This situation must be rectified very soon if California is to avoid renewed supply shortages.** RMR Condition II (RMR CII) units cannot be subject to the must-offer requirement. The must-offer requirement was designed to eliminate the potential for physical withholding and was adopted during a time of market dysfunction. By entering into a bilateral RMR CII contract with the CAISO, a resource owner gives dispatch control to the CAISO according to the terms of the RMR agreement,

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		ISO does not yet have a proposal for disbursing profits in excess of fixed costs. Because such profits should not go back to the unit Owner (there should be no way to earn a profit by putting the unit on Condition 2) or to the PTO (it would be perverse to earn moneys because of a need for RMR service), it may be most reasonable to credit those moneys to all market participants instead.		No. Commitment and dispatch of an RMR unit must be done in accordance with terms and conditions of its RMR contract. When the RMR assessment was done it was done to procure a certain service. Also, the costs from RMR are borne by the TO in which the RMR is located, not the system so it would be unfair for an area with more RMR to pay for the "system need" procured through MO. In addition, utilizing RMR units whose fixed costs are paid for and whose energy price is cost-based, will tend to distort the market by severely reducing the opportunities of non-RMR units to have their bids dispatched from a competitive BEEP stack. In addition, units located in SP15 that are called on for Must-Offer are clearly being used as an		there will be no need to commit RMR Condition 2 units for system needs. However, once a Condition 2 unit has been committed for local reliability needs, the CAISO may <u>dispatch</u> the non-market unit to meet system requirements in an emergency (i.e., when alternative market supply bids have been exhausted). The RMR Condition 2 contract relates to uneconomic units that are needed for local reliability purposes in load pockets, that would not otherwise pass a reasonably-applied competitive solution test in the face of locational price signals, and that are otherwise slated for retirement by their owners. **NEED FOR LOCAL RESOURCES OTHER THAN ANNUAL RMR UNITS** If RMR units are properly contracted by the CAISO, there is no reason to subject them to a must-offer requirement; since the CAISO has a contractual right to commit the capacity for		which is intended to address solely local reliability needs. There is no possible way that a resource owner could be construed to be withholding for abiding by the terms of its RMR contract. RMR CII units should not be committed day ahead (DA) for system-wide needs. RMR CII units subject to run-time or other environmental limits should not be called for system wide needs as such calls would impair the resource owner's ability to perform under its RMR agreement and could jeopardize local reliability in a later period. Under the RMR agreement, RMR CII units can be dispatched only pursuant to the terms of the agreement, *i.e.*, for local reliability reasons. Although tariff Section 5.6.1 states "All Generating Units, System Units and System Resources that are owned or controlled by a Participating Generator are (without limitation to the ISO's

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				RMR replacement in which it was not designed (nor ordered by the Commission) to be used for. IEP believes this is an abuse of the Must Offer and again sends perverse incentives to LSE's. At a minimum, the CAISO MUST reevaluate the RMR designation criteria. It is clear that the current criteria are insufficient. It is IEP's observation that the "planning" criteria utilized for RMR has little, if any, barring on "operational" criteria needed to keep the lights on. With the historical data available (at least over the last 18 months) it would be completely irresponsible for the CAISO not to consider the SYSTEMIC locational problems in SP15 when designating the 2005 RMR units.		its local reliability needs. However, the CAISO cannot contract for RMR units with perfect knowledge months in advance. The CAISO therefore finds itself in need of "local reliability" resources that have no RMR contract. Under Reliant's proposal (described in the answer herein to "Must Offer Mechanics"), the CAISO could acquire these local reliability resources ("LR") by applying a methodology recently proposed by Reliant in comments filed at the FERC (in PJM Docket No. EL03-236-000). This proposal, the "System Surrogate Unit methodology" or "SSU" is an alternative design for mitigating local market power based on competitive market principles with the operational flexibility to meet the needs of CAISO operators. In fact, the SSU methodology mitigates local market power without requiring additional local AMP tests. With one minor adjustment to the process proposed by the CAISO, the SSU methodology can be		other rights under this ISO Tariff) subject to control by the ISO during a System Emergency and in circumstances in which the ISO considers that a System Emergency is imminent or threatened", the RMR Agreement states that the Agreement shall control in any conflict with the ISO tariff. To the extent that it is ultimately construed that an RMR CII unit must be dispatched to meet a system-wide need, CAISO should only call on these units when it is in a declared emergency. System emergencies by definition imply that the CAISO is relying on operating reserves to meet energy requirements. CAISO RT energy and AS prices fail to reflect the true cost of meeting demand and reserve requirements during periods of reserve shortage. In New York (ER03-766, Order dated June 20, 2003) and New England (ER03-854, Order dated July 25, 2003), FERC has adopted scarcity pricing

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						applied in concert with the CAISO's day-ahead transmission constrained unit-commitment ("TCUC") procedure; the minor process adjustment being that the CAISO operators would identify local reliability ("LR") units at the same time of the day that they identify RMR units for commitment/dispatch notification. That is, LR owners would be notified at the same time that the CAISO notifies RMR owners of next-day's commitments. (See Reliant comments filed in CAISO FERC Docket No. ER02-1656-018 that attaches Reliant's SSU methodology originally filed in PJM FERC Docket No. EL03-236-000). **SUMMARY** In summary: (1) RMR Condition 2 units should not be subjected to must-offer requirements; (2) RMR Condition 2 units should only be committed for local reliability needs, and (3) between now and the time that the CAISO implements a properly designed Resource		rules that set RT energy prices during reserve deficiencies at $1,000/MWh. A similar policy should be adopted for the CAISO system. To reflect the value of RMR CII capacity, RMR CII units should receive the higher of an adopted scarcity price or its RMR contract Schedule G rate. Revenues in excess of RMR contract costs should be shared between the local Responsible Utility and the RMR CII unit owner.

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						Adequacy market and a nodal LMP system with reasonably-applied competitive solution test, the CAISO should make use of unit-specific LR capacity when it is needed (i.e., when no competitive solution exists) to satisfy its local reliability needs and only utilize RMR capacity as a last resort. The costs of the available LR capacity would be allocated on the same basis as RMR costs.		
Purpose of Must-Offer Obligation	For what and how should the Must-Offer Obligation be used? Should it be used for local requirements?	The Must-Offer obligation is used to ensure Market Participants do not withhold available capacity from the ISO's markets. The ISO uses the must-offer obligation to obtain capacity need to meet system and local reliability requirements.	The Must Offer obligation arose as part of an interrelated package of <u>temporary</u> price mitigation measures during the height of the California energy crisis. 95 FERC 61,418. The stated purpose of the Must Offer obligation was to prevent physical withholding by generators exercising market power. 100 FERC 61,060 at ¶44. At the time the Must Offer Obligation was imposed by FERC, no resource adequacy requirement ("RAR") was in place. As a result, the CAISO started to improperly rely on the Must Offer obligation as a means of	The MO Process was originally implemented by FERC to prevent physical withholding. It was not designed to be used as a replacement for RMR, A/S procurement or Supplemental Energy procurement. It was not designed to purchase capacity nor be a surrogate for Resource Adequacy. Based on information provided to Market Participants from the CAISO, it appears that the overwhelming majority of Must-Offer	In response to FERC imposed obligations, the Must-Offer should be used to assure energy and capacity are not being withheld from existing markets must offer assures the unit is physically available to provide energy and ancillary services, if needed. Suppliers complying with a must offer obligation are not hindered in any way from selling energy or capacity from their units, either forward or in the Day Ahead or Hour Ahead time frames. Must offer does not diminish any value realizable by the supplier.	RELIANT'S COMMENTS: The must-offer requirement is not a product. The must-offer requirement is, at best, an obligation imposed on generators by the FERC to address the potential withholding of physical generating capacity absent the proper market design. The must-offer requirement appears to be used by the CAISO to acquire both capacity and energy, for both local and system purposes, at its sole discretion and at levels not explicitly provided for in the CAISO Tariff	MO should not be used as a substitute for any product. MO was intended by FERC to only be a mitigation measure for preventing physical withholding and not a market used for the procurement of a product. The use of MO to procure a "product' undermines the effectiveness of current markets by providing generators a disincentive to bid into the markets when their MO wavier is denied. MO should be used as the resource of last resort and run only to the extent there are insufficient DA energy schedules [taking due consideration of likely	"Must-offer" (MO) is neither a resource nor a product but is a requirement to fully offer all available energy in real time. The MO waiver process should be phased out on an expedited basis and replaced with (1) meaningful RAR imposed on load serving entities (LSE's), (2) improved RMR designation criteria so that units called for local reliability needs receive scarcity pricing or a compensatory contract and (3), for remaining system wide reserve deficiencies, a RUC mechanism with a market-based

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			obtaining energy for system-wide and local needs. The Must Offer Obligation should be phased out and replaced with an RAR obligation on the Load Serving Entities. An RAR, including long-term power purchase commitments, is especially crucial to encourage the development of new generation.	calls are in Southern California (approx. 95% over the last 12 months). This is of particular concern because the costs associated with that Southern California procurement (in excess of $100 million YTD) is assessed to ALL load and Exports. The CAISO is often procuring capacity at levels exceeding 12% of the peak load. It seems that the Must Offer is being used for both "reliability" reasons and to meet the local reliability criteria for Southern California (a service historically reserved for RMR). MOP should be used solely to prevent physical withholding. It should not be used to procure RMR reliability needs, system capacity, or Replacement Reserve. Because the MO was only implemented to	To the extent withholding causes local reliability problems, using Must-Offer to mitigate the withholding will solve those problems. If withholding is not the cause of those reliability problems, then other mechanisms (e.g., RMR or OOM) should be used.	(e.g., "manual" as well as "dispatchable" minimums); the results of which add wear-and-tear to generating equipment forced-on to operate at minimum load levels, distort prices and multiply the number of disputed financial settlements. Reliant does not support continuing the waiver denial form of Must-Offer as currently implemented in California, and it should not be used to meet local reliability requirements. Instead, Reliant believes the CAISO should implement the proposed System Surrogate Unit methodology referenced in the section herein entitled "RMR Condition 2" and further described in the section herein entitled "Must Offer Mechanics". Reliant's proposal can be implemented now and is readily adapted to local market power mitigation within the MD02 nodal LMP design. In the future, under a properly designed Resource Adequacy market that designates	HA energy schedules] or bids in the AS and Imbalance markets. If after using these markets the CAISO needs additional resources for reliability requirements, it should use the MO. MO should not be used for local area reliability when RMR units are available. For normal local reliability needs, the CAISO has the LARS/RMR process for satisfying the local reliability need.	availability payment. Local reliability needs should first be met by an RAR with strict deliverability criteria. Such a mechanism will create incentives for LSEs to bid for, and contract with, local reliability resources thus eliminating any need for must-offer (although contracts entered into as a result of an RAR may, as a reasonable contractual requirement, impose requirements to bid all available capacity in ISO markets.). To the extent not contracted pursuant to RAR, the CAISO should contract with all resources needed to provide local reliability that cannot recover costs from mitigated market prices. Units needed for local reliability without a contract should receive a daily price that reflects local scarcity value. The large and persistent amount of must-offer capacity procured in SCE's service territory is evidence that CAISO's RMR designation criteria is flawed and must be

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				prevent physical withholding; it should not be a replacement to meet any operational reliability criteria or market product. If the CAISO deems that there is additional Capacity and/or energy required to meet the reliability of the grid than the CAISO should publish the amount of capacity it needs on a system basis and establish a market mechanism for meeting that need. In addition, if there is a local reliability need the CAISO should sign RMR contracts, even if the incumbent utility objects.		the required resources several years in advance, an obligation to offer into spot markets could be applied with respect to solving both local and system-wide reliability requirements under a market-based, security constrained, financially-binding, unit commitment program; replacing the need for some of the currently designated RMR units and removing the need for the explicit treatment of LR units. The designation of LR units, explicitly described herein, is implicitly a part of the SSU methodology that Reliant would recommend as the market-oriented alternative to the local market power mitigation mechanism of the MD02 design. Must-Offer should not be used to address problems that should otherwise be solved with RMR contracts and local reliability (LR) units.		reformed. In addition to the annual designation process, resource owners intending to remove units from service that have notified the CAISO should trigger a mandatory needs assessment by the CAISO and, if needed, a contract offer by the CAISO. Any residual resource requirements DA or hour-ahead (HA) should be met with a RUC mechanism. In its October 28, 2003 Order on CAISO's market redesign, the FERC recognized that RUC is intended to replace the must-offer waiver process and that RUC resources should receive a bid-based availability payment. FERC recognized that CAISO's proposal to commit capacity DA was tantamount to a free call on capacity and rejected its proposal to procure such capacity for free. (Note that expedited implementation of RUC may require a relaxation of the current balanced schedule requirement or a phase-in of DA energy markets in advance of

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								LMP. WCP supports phase in of market redesign elements as a way to expedite the date when CAISO can commit resources and clear congestion DA using market-based mechanisms. Pending implementation of these reforms (RAR, improved RMR designation criteria, and RUC), the must offer procurement mechanism must be operated in a manner that provides waiver-denied resource owners a reasonable opportunity to recover costs including a return on capital.
Must-Offer Mechanics	How should Must-Offer minimum load energy be treated? What information should be logged? Should the ISO use TCUC or continue "first-come, first-served?" If the ISO uses TCUC, what should the objective function be? Should the waiver requests be implicit or explicit? How do you treat self-commitment vs. "buy-back"? What is the interaction between Must-Offer and "Day-Of" call rights?	**Scheduling.** The ISO believes that Must-Offer Minimum Load Energy should not be forward scheduled, but if it is, it must be forward-scheduled to specific Demand IDs. TCUC. Must-Offer capacity should be committed to minimize start-up and minimum load costs through a Transmission-Constrained Unit Commitment application once reliability needs are provided for.	**Waiver Evaluations:** The CAISO should only deny a waiver request when there is evidence of physical withholding that prevents the CAISO from obtaining operating reserves. Local reliability needs should be met through an RAR obligation with strict deliverability criteria designed to ensure that local reliability needs are met. General system needs should be met through the energy markets, including power purchase	Min Load energy should be treated as instructed energy. It is unclear if the costs associated with the MinLoad energy are assessed to all load and exports or just too net deviations in real-time. It is important that the CAISO clarify this point. IEP does have some concerns with regard	Except for reliability reasons in SP15, it appears waivers are granted on a first-come/first-serve basis. Economic criteria do not appear to be taken into consideration in the granting of waivers. The ISO needs to develop criteria that take economic issues into consideration. This requires consideration of unit effectiveness and unit size Must-Offer does not in nay way interfere with Day Of Call rights, Must Offer	**On March 25, 2004, the CAISO Board resolved:** **"1) Implement a Security-Constrained Unit Commitment application to commit units under the Must-Offer obligation to minimize Minimum Load and Start-up cost;"** RELIANT'S COMMENTS: As previously explained in the comments regarding "RMR	MO minimum load energy should be scheduled with the CAISO through CAISO defined Load IDs. Uplift costs should be allocated to scheduling deficient SCs before spreading across all loads. The CAISO should uses TCUC making the choice on the basis of effective operating costs which include actual operating costs over expected run time, impact of operating constraints (e.g., high	*How should Must-Offer minimum load energy be treated?* Minimum load energy should be treated as instructed energy and paid minimum load cost (MLC) compensation. Pending implementation of a capacity payment mechanism, minimum load energy should also receive a proxy capacity payment based on the instructed energy price. *If the ISO uses Transmission Constrained Unit*

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Category	New Question(s)	CAISO	Calpine Corporation	Independent Energy Producers Association	PG&E	Reliant	SCE	West Coast Power (WCP)
		Units that do not have Day-Ahead Schedules shall be deemed to have implicitly requested a waiver. A unit shall be deemed Self-Committed for those hours for which it has Day-Ahead Energy Schedules. The Owner may explicitly request a waiver for Self-Commitment periods, but if ISO does not grant the waiver the ISO shall not pay minimum load costs for Self-Committed hours.	agreements. When evaluating waiver requests, the CAISO should not grant or deny waivers in order to minimize start-up and minimum load cost. Cost competitiveness is not an indication that a Seller is physically withholding energy from the market. The current CAISO proposal discriminates against efficient, low-cost generators; is a disincentive to construction of more efficient generation in California; applies a punitive measure based on criteria that are not reasonably related to the action Must Offer seeks to mitigate; and is counter to law and public policy. Moreover FERC has previously rejected the CAISO's proposal criteria to grant exemptions to minimize start-up and minimum load costs. 99 FERC 61,158. **Scheduling:** Energy dispatched pursuant to the Must Offer obligation should be scheduled. Throughout its operation, the CAISO has consistently stated	to the new TCUC program proposed by the CAISO because it will only model inter-zonal constraints. All of the data submitted by the CAISO to the market seems to indicate that the large majority of resources procured through Must-Offer are due to intra-zonal constraints. A zonal TCUC program will do little to alleviate this intra-zonal issue.	applies only to realtime. In an ideal world, minimum load energy would be made available to SCs. However, in recognition of the difficulties encountered in attempting to place RMR energy, it does not appear feasible to do so at present.	Condition 2", Reliant does not support continuing the current waiver denial process and proposes a procedure below that complements the CAISO's TCUC analysis to minimize CAISO's reliance on capacity acquired by means of must-offer waiver denials. **REPLACING THE "FIRST-COME FIRST-SERVED" PROCESSES WITH PROCEDURES THAT DIFFERENTIATE LOCAL VERSUS SYSTEM MARGIN REQUIREMENTS** It is Reliant's understanding that the CAISO proposes to run TCUC after the day-ahead ancillary service market is completed. This is appropriate as the market should have the first opportunity to satisfy the CAISO's reserve requirements; however: • Prior to the day-ahead markets, the CAISO will continue to perform its daily studies to determine which RMR units are to be notified for next	vs. low minimums, long vs. short start up times, etc.), and effectiveness in resolving reliability concerns (i.e., location, unit size, etc). If the MO is defined and used correctly, conflicts between MO and bilateral contract rights should be rare if at all. In addition, such conflicts cannot be reconciled while simultaneously redefining what MO is or how it should be used.	*Commitment (TCUC), what should the objective function be?* Note that per CAISO's description, TCUC will only used to determine resources needed above and beyond what is needed for local reliability. The objective of the TCUC should be to minimization of capacity payment, startup costs (including aux power), and minimum load energy. Expected dispatched energy costs should not be included. *How do you treat self-commitment vs. "buy-back"?* Units with short lead times should be able to de-commit units post-DA without financial penalty. If CAISO needs the capacity, it should recommit the unit (via RUC or via a waiver denial) with full cost compensation. FERC has consistently maintained that CAISO pay for units it needs to commit for reliability needs.

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Category	New Question(s)	CAISO	Calpine Corporation	Independent Energy Producers Association	PG&E	Reliant	SCE	West Coast Power (WCP)
			that all energy and ancillary services must be scheduled if the CAISO is to properly manage system reliability. The CAISO has provided no justification for its deviation for Must Offer energy nor has it tendered any assurances that its failure to schedule minimum load energy is not having a detrimental effect on system reliability. From a generator's perspective, not scheduling minimum load energy increases the complexity of a generator's real-time operations associated with the Must Offer obligation. Scheduling would help endure that units do not over-generate or under-generate during waiver denial periods. In addition, scheduling would either eliminate, or significantly reduce, the significant settlement and billing disputes currently associated with the Must Offer obligation. The CAISO's current systems do <u>not</u> provide for appropriate tracking			day's operation. These are the same studies that identify the other units that are required in other local areas for next day's operation (i.e., these are the local reliability units ("LRs") that were not previously identified or contracted for in the CAISO's annual LARS process). • The CAISO would then notify LR units on the same day-ahead timeline that it notifies RMR units to satisfy its local reliability requirements. RMR units would not be notified in those instances where adequate LRs exist to resolve the CAISO's local reliability needs. • The CAISO would then run TCUC, after the day-ahead markets close, to determine what other resources may be required, if any, to fulfill the remainder of its "Margin" for system requirements with must-offer waiver denials. The objective function of TCUC is therefore a least-cost, security constrained commitment of non-		

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Category	New Question(s)	CAISO	Calpine Corporation	Independent Energy Producers Association	PG&E	Reliant	SCE	West Coast Power (WCP)
			and payment of Must Offer energy costs.			RMR capacity. The TCUC process will therefore assure that any additional units, subject to must-offer, will not be committed in the wrong location that would cause other local reliability problems. Reliant also understands that the above process may be performed, as required, during the CAISO's day-of processes to satisfy any additional local and/or system reliability requirements. These procedures should replace the current "first-come first-served" CAISO processes. **TREATMENT OF RMR MINIMUM LOAD ENERGY** RMR contracts are utilized to keep uneconomic resources available for local reliability purposes when no competitive solution exists. RMR energy should be settled in accordance with the relevant RMR contract. **TREATMENT OF LR MINIMUM LOAD ENERGY** LR units should only be used to solve situations of local market power;		

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Category	New Question(s)	CAISO	Calpine Corporation	Independent Energy Producers Association	PG&E	Reliant	SCE	West Coast Power (WCP)
						i.e., when no competitive solution exists to address the local reliability constraint. LR units should be paid based on the higher of the settlement interval zonal MCPE or SSU Threshold Price. The SSU Threshold Price is calculated as follows: SSU Threshold Price = [System Surrogate Heat Rate x (Fuel Index + Applicable Delivery Charges)] + $6-$10/MWh Variable O&M + (System Surrogate Emissions Rate x Emissions Allowance Price) + Start Up and No Load Costs (where applicable) (See Reliant comments filed in CAISO FERC Docket No. ER02-1656-018, that attaches Reliant's SSU methodology originally filed in PJM FERC Docket No. EL03-236-000, for the details of this calculation). **TREATMENT OF MUST-OFFER MINIMUM LOAD ENERGY**		

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Category	New Question(s)	CAISO	Calpine Corporation	Independent Energy Producers Association	PG&E	Reliant	SCE	West Coast Power (WCP)
						Until MD02 is fully implemented, Minimum Load energy should be financially settled as instructed imbalance energy, in addition to the other components of the compensation for generators operating under Must-Offer that are necessary to assure that generators will not exit the market due to economic reasons. See "Compensation" section herein for Reliant's comments on the required must-offer compensation components. **THE NEW PROCEDURE SHOULD BE COMPENSATORY** Whether a unit is committed by the CAISO as RMR, LR or Must-Offer, the payment for such service must be compensatory and the CAISO Tariff should reflect this commitment. • This should be the case in all circumstances, including those circumstances in which the CAISO commits a resource on a day-ahead basis but then later decides to de-commit it for any reason.		

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						• Likewise, if a Scheduling Coordinator self-commits a unit in the day-ahead process and then later decides to de-commit it for any reason prior to the actual hour of operation, the Scheduling Coordinator is responsible for buying back the committed capacity at the cost incurred by the CAISO to maintain its published requirements. • Scheduling Coordinators should be able to substitute units, of like capacity and ramping characteristics, subsequent to the commitment process and with timely notification to the CAISO (e.g., if forced out or de-rated or otherwise inoperable for whatever reason) without suffering any buy-back costs or penalties. **LOGGING / PROCESSING** All communications with Scheduling Coordinators or their resources		

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						should be logged, whether RMR, LR or Must-Offer, and all relevant operational notifications thereof transmitted to Settlements for payment processing and appropriate cost allocations. See "Cost Allocation" section herein for Reliant's related comments. **TRANSPARENCY** The CAISO should issue/deny waivers based on a strict, transparent set of criteria that are approved by FERC and known to market participants ahead of time. See "Information Communication" section herein for Reliant's related comments.		
Capacity Procurement	What should the ISO's capacity procurement target be? How should the ISO meet that target? How was it met before?	Required on-line capacity = ISO Demand Forecast + Required Operating Reserve + Capacity needed for local reliability + max (0, ((Margin * ISO Demand Forecast) – Available Short-Start Capacity) where "Margin" is	The criteria the CAISO uses should require on line the types and amounts of capacity reasonably needed to meet WECC requirements for the forecasted system conditions—and no more. Ultimately, the criteria need to demonstrably conform to WECC requirements.	Based on the information provided to market participants the CAISO is currently procuring about 12% of its peak load; 7% through normal A/S self provision or procurement and the remainder secured through the MO.	The ISO should be procuring reserves consistent with its tariff and WECC standards. To the extent it feels reserve in excess of the tariff and standards need to be procured, it should follow the procedures stated in Sections 5.1.5 and 5.5 of the TCA to revise those reserve amounts. The criteria the CAISO	RELIANT'S COMMENTS: **CAPACITY PROCUREMENT TARGET** In its December 19, 2003 Must-Offer Position Matrix, the CAISO provided the following calculation of "required on-line capacity":	The amount of reserves the CAISO should be procuring is not and should not be considered a MO issue. MO was not intended to be a substitute mechanism for securing operating reserves. The CAISO should procure capacity to cover its forecasted load and WECC MORC requirements which	CAISO's capacity procurement target should be sufficient to ensure reliability but not be set so large as to manage energy costs for load by depressing the RT price of power. CAISO's current method significantly discounts available capacity from quick start units, such as combustion turbines.

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Category	New Question(s)	CAISO	Calpine Corporation	Independent Energy Producers Association	PG&E	Reliant	SCE	West Coast Power (WCP)
		approximately 2-3% of the ISO's Demand forecast in the off-peak season and 5-8% of the ISO's Demand forecast in the peak season. Capacity above the requirements for local reliability from units committed for local reasons should be counted as available for system needs. The ISO makes the following assumptions: 1.) Thermal generation: The amount available is determined from forward schedules and outage status. Long-start units are not considered available unless they are operating at least at minimum load. 2.) Hydro and other limited fuel generation: All available generation is already committed through the forward market schedules; no additional real-time hydro is available. 3.) Imports: Forward schedules plus a forecast of additional real-time participation based on the last few days'	If there is no evidence of physical withholding, any shortfall (as defined by WECC standards) should be met through market-based mechanisms.	If there is a local reliability need than there should be an RMR contract. It is possible that the CAISO needs to consider an interim reliability product if the yearly RMR assessment is not meeting the local reliability needs. However, there should be no reason for the CAISO not to consider the historical data available for the systemic problems in SP15 when committing 2005 RMR resources. In fact the Commission should require the CAISO to justify why its RMR "planning" criteria does not sufficiently provide resources to meet systemic operational challenges. IEP believes the (operating reserves + MO reserves) requirement should be public, both from the determination of the criteria and the	uses should require on line the types and amounts of capacity reasonably needed to meet WECC requirements for the forecasted system conditions—and no more. Ultimately, the criteria need to demonstrably conform to WECC requirements. If the ISO adopts adherence with WECC standards, a shortfall may not exist.	*"Required on-line capacity =* *ISO Demand Forecast +* **Required Operating Reserve +** **Capacity needed for local reliability +** *max (0, ((Margin * ISO Demand Forecast) – Available Short-Start Capacity))* *where "Margin" is approximately 2-3% of the ISO's Demand forecast in the off-peak season and 5-8% of the ISO's Demand forecast in the peak season. Capacity above the requirements for local reliability from units committed for local reasons should be counted as available for system needs."* Reliant could generally agree with the CAISO's proposed criteria and formula provided above for a capacity procurement target, depending on a common understanding of the undefined terms and the basis upon which "Margin" is defined. **HOW CAISO SHOULD MEET TARGET** The CAISO should	should normally be obtained through their established markets or self-provision mechanism. As in the proposed MD02 RUC process, MO commitments should occur after day-ahead market activity only if a reliability problem still exists. As indicated in the CAISO answer to question 2-1 in the original MO position matrix, the CAISO uses its established market/self-provision mechanisms to procure operating reserves according to WECC MORC requirements but is using MO to commit additional capacity beyond that needed to serve forecasted load and WECC MORC.	Quick-start-unit available hours should be allocated to peak load periods. During those periods, quick start units should be counted for 100% of their capacity and continue to be counted until their available runtime hours are used up. Ignoring quick start units unnecessarily increases commitment of slow-start units, increases must-offer costs, and depresses the RT price of power. Any SC should be able to self provide reserves to meet whatever procurement target is set by CAISO

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		experience. 4.) Municipal generation: Only the amount of municipal generation committed through forward schedules is considered available. Other municipal capacity is only available to the ISO in an emergency. 5.) Wind generation: Currently, the amount of wind capacity is subtracted from the amount of available capacity because that amount is not developed from a rigorous forecasting process and may not be dependable; under worst-case conditions, the ISO would have to meet those forward schedules through the imbalance energy market. When the forecasting process proposed in the Participating Intermittent Resource program is functional, the ISO expects to consider the forecast amount of wind generation as available and dependable.		process for committing services to meet that criteria. IEP believes the CAISO has taken some important steps to further clarify this process to the market through both a new operating procedure and additional information to be posted on the OASIS. Recently the CAISO has indicated they plan (June 2004) to begin procuring Ancillary Services on a regional basis. IEP request that the CAISO clarify how the MOP will be affected when the CAISO begins regional procurement.		establish and make transparent to market participants the types and amounts of reserves necessary, within a market-based system, to assure reliability. There should be a consistent methodology for the CAISO's counting of what resources are available. The CAISO's application of the method should, at a minimum, assure that system needs are being met with market resources. Reliant believes that its proposed process, described above in the "Mechanics" section, accomplishes this purpose. Assuming the amount of required generation and resulting shortfall are accurately determined, the CAISO should use market mechanisms, including balancing energy, ancillary services capacity and LR resources, to cover shortfalls versus its present use of the waiver denial process (which supplants markets). In the future, the CAISO		

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						should not develop processes and systems that calculate "shortfalls", per se, but should, instead, implement a market-based, security-constrained, financially-binding, unit-commitment program to assure that it has the resources required to maintain system reliability based on its forecasts and to have sufficient energy bids available in real time markets. The CAISO should create transparent procedures that specify its actual capacity needs, and then rely on market mechanisms to meet that need (*e.g.*, a combination of self-provision and purchases through the A/S markets). These reforms would eliminate most, if not all, of the "shortfalls". **HOW TARGET WAS MET BEFORE** It is Reliant's understanding that the CAISO routinely secures a capacity margin of 3-8% above and beyond the minimum contingency reserve level (for a total of 8-		

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						15% reserves). The actual amount of capacity margin secured by the CAISO each day seems to typically depend on the peak load level, with the additional 3% margin being required on low load days and up to 8% on peak load days. In addition to the contingency reserve and capacity margin, the CAISO also has certain locational reserve requirements that it satisfies.		
Information Communicatio n	What information should the ISO provide regarding its capacity procurement practices? When?	The ISO shall develop and post operating Procedure M-432C, which describes the ISO's Must-Offer capacity commitment practices. The ISO shall log the reason for all waiver denials and provide the reason to Market Participant. The ISO shall post the following information for each hour with a one-month lag: 1. The ISO's on-line capacity target (i.e., the number determined by the formula above and each component of	Calpine generally supports the position of Reliant Resources. Operationally, the CAISO should clarify at dispatch the amount of energy required under Must Offer obligation to eliminate settlement and billing conflicts after-the-fact. Often the CAISO and unit have differing definitions of "min gen" and a dispatch instruction articulating the actual amount of energy required would minimize confusion on whether the 3% deviation band was satisfied or not. CAISO should clarify at dispatch the duration of the Must Offer obligation	The CAISO should, and according to the proposal will be moving toward, a more transparent MOP. The CAISO should set up a regular reporting mechanism to the market on the MO process. Some suggestions for ongoing information are: Reliability criteria (by UDC and Zone) Procurement of reliability criteria (by UDC and Zone) Use of RMR to meet system need (by	The ISO needs to explain its Must-Offer decision-making process to Market Participants. It should have an easily understandable and well-communicated pro forma procedure for determining Must-Offer waivers. The pro forma procedure should not include operator judgment. When operator judgment requires deviation from the pro forma, then the ISO must communicate the specific reasons for those deviations to Market Participants. In order to determine if deviations have taken place, the ISO needs to document its daily Must-	RELIANT'S COMMENTS: The CAISO should be transparent in all aspects of its capacity procurement process and set up a regular reporting of public market information, including but not limited to: reliability criteria; procurement criteria; hourly "Margin" if any and for what purpose(s); hourly RMR, LR, and must-offer notifications; hourly RMR & LR operating results by relevant zone, UDC, local transmission	The CAISO currently conveys an insufficient amount of information regarding MO. Ultimately, what is needed is for the CAISO along with stakeholders to develop a MO process similar to that discussed in the MO mechanics section above.	WCP supports the position of Reliant Resources.

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		that formula). 2. For each zone, the total number of units and amount of capacity for which must-offer waivers were denied or revoked, classified by the reason for the revocation or denial. 3. For each zone, the amount of capacity provided from units for which waivers were denied or revoked, and the minimum load cost of those units.	to permit the generating unit to procure sufficient natural gas.	UDC and Zone) Level of MO procured and where (by UDC and Zone) Reason for MO procurement (by UDC and Zone) Reason for Waiver Denials (by UDC and Zone)	Offer determinations and this documentation must be made available to Market Participants. This information should also include size, location, and reason Must Offer Waivers were granted and denied. In addition, cost details associated with Must Offer should also be provided. The pro forma procedure should be made known to Market Participants as soon as it is developed. It is logical that deviation information should not be made available as long as it could affect participants' market decisions. However, it needs to be made available by the time invoices for recovery of MLCC are issued. The Department of Market Analysis (DMA) needs to propose a schedule. Because the ISO has no financial resources of its own, accountability is a real problem. Any accountability proposal must be fair and balanced towards all Market Participants. This is difficult, because Market Participants are on both sides of the	constraint or relevant operating procedure; hourly use of RMR and must-offer to meet system need; hourly level of must-offer procured and where; reason for each must-offer waiver denial; historical hourly values of Regulating capacity, Spinning capacity and Non-Spinning capacity as archived from the CAISO's Energy Management System's Reserve Monitor. The CAISO should electronically communicate its capacity requirement via the CAISO OASIS on a continuous basis, as updated in the Day-Ahead processes and throughout the Day-Of processes. This Day-Ahead and Day-Of updating of the CAISO's spot market capacity requirements should also be included in the "end-state" in which the CAISO will be facilitating a Resource Adequacy process. Communicating its actual capacity requirements in advance would allow the CAISO		

ATTACHMENT D

Comparison of Aggregated Monthly Spot Gas Price to Regional Daily Spot Gas Price

The ISO is proposing the use of gas price indices reported daily at regional hubs as the basis for calculating Minimum Load Cost Compensation ("MLCC") for compensation for units whose must-offer waiver has been revoked or denied ("MOW units") in lieu of the current practice of using the average of monthly bid-week indices across three California delivery points.

There are two simultaneous changes occurring with this portion of the proposal. First, the move from monthly bid-week to daily spot indices is more in line with the unit commitment process as practiced under the must-offer obligation. Units committed under the must-offer obligation tend to be units not under forward contract, so the gas for these units is not procured far in advance (i.e., a month ahead) but purchased instead on the spot market. Since the number or frequency of units committed through the must-offer waiver denial process cannot be predicted, such units necessarily operate on spot gas, not forward monthly gas, arrangements.

Second, the move from a system aggregation of hub prices to the use of regional hub prices in the compensation formula eliminates any bias in the aggregated index stemming from systematic differences in gas prices between the north and south. Any systematic difference in price between the regions would have created an un-earned windfall for generators located in Southern California, while the gas price is diluted for generators in Northern California by the lower Southern California gas index.

Figure D1 - Average Daily and Monthly Spot Gas Prices.

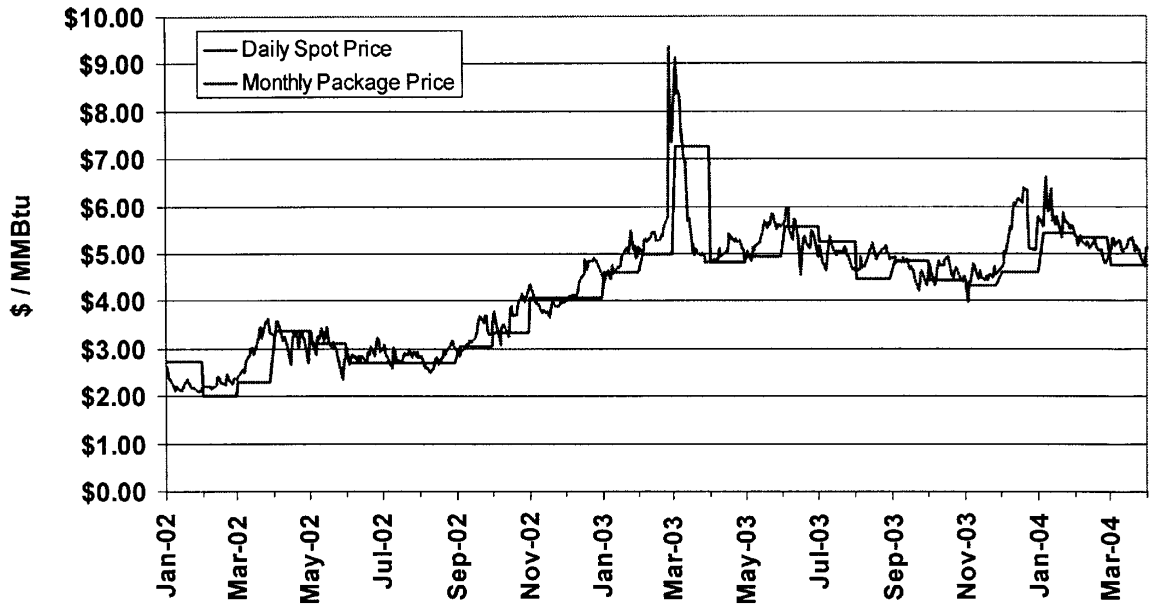
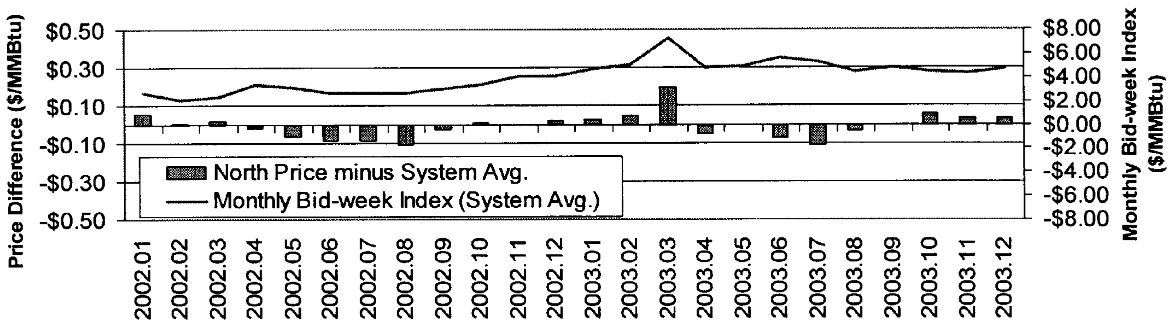
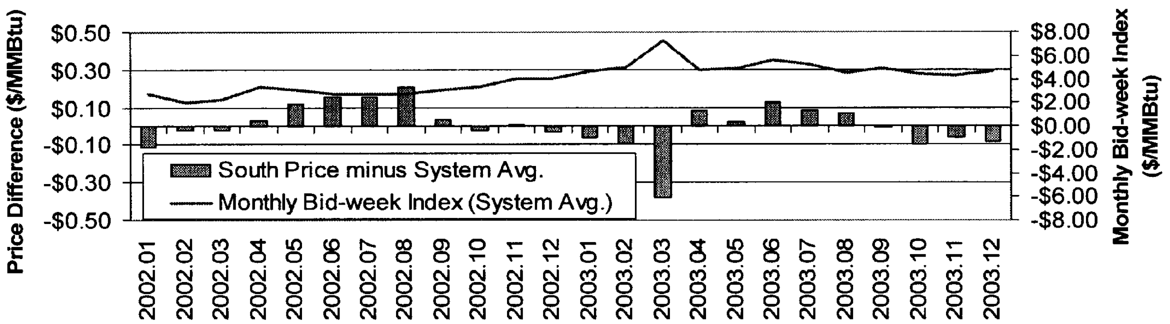


Figure D1 illustrates the difference between the daily spot index (the jagged series in red) and the monthly bid-week index (the blocked series in blue). To facilitate comparison with the system average monthly bid-week index currently in use, the daily index reported in Figure D1 is a system average of the northern and southern hub prices. Note that although the daily and monthly indexes move together, significant differences do occur when dramatic changes are observed in the daily index and the monthly bid-week index does not adjust until the following month. Because the ISO does not commit a unit under the most-offer obligation until the day-ahead time frame, gas purchases are likely to be made from the daily spot market. A lagging price index based on month-ahead contracts does not adequately reflect the fuel costs incurred to cover the day-ahead must-offer commitment. As seen in Figure D1, this can be especially pronounced when persistent movements in the daily spot index are observed.

Figure D2 below shows the average difference between the regional monthly bid-week prices and the aggregated system average monthly bid-week prices for 2002 and 2003.

Figure D2 - Difference Between Regional and System Monthly Bid-week Prices (North comparison on top, South comparison on bottom).





As illustrated in Figure D2, some months show a difference between the regional hub price and the system aggregated price of as much as \$0.38 / MMBtu with a range of -\$0.38 / MMBtu to \$0.21 / MMBtu. However, on average across the two years shown the average difference between regional and system average prices \$0.005 for the South and -\$0.007 for the North, both less than \$0.01 / MMBtu in magnitude. Since the amount of minimum load energy procured from MOW units varies across months, the impact to MLCC payments would be somewhat different from the simple averages stated above but would still be small as measured per MWh of minimum load committed via waiver denial. To improve the accuracy of compensation compared to actual costs occurred, the ISO believes moving from a system-aggregated price index to the use of regional prices is warranted.

As noted in the transmittal letter, the Commission has indicated that no party, including the ISO, has yet presented information that would provide assurances that the daily gas indices are suitably free from manipulation. However, the ISO currently uses a two-day location-specific average of daily gas indices to set the energy price for RMR Units. While the ISO does not have specific information indicating the daily gas indices are free from manipulation, the ISO does feel the daily indices are more suitable for the commitment process incurred by the must-offer process and is consistent with the input cost basis specified for RMR units. The ISO is encouraged by the fact that Staff issued a conditional recommendation[1] that all three of the indices the ISO is proposing to use - Platt's Gas Daily, NGI and Btu - be deemed to be in substantial compliance with the Policy Statement on Natural Gas and Electric Price Indices (July 2003) and subsequent clarifications to the Code of Conduct for jurisdictional sellers and holders of blanket certificates issued by the Commission in November 2003. The ISO is also encouraged by Staff's report on current Commission actions to improve the integrity of reported price indices[2] and believes the price reporting framework prescribed by Staff, along with Staff's monitoring activities, will serve to mitigate manipulation going forward..

Table D1 shows the financial impact of moving from aggregated monthly bid-week prices to daily regional prices. The energy procured at minimum load, along with the natural gas required to provide minimum load energy, are reported along with two MLCC payment calculations. The MLCC was re-calculated using the regional daily price index and is compared to the actual MLCC calculated using the aggregated monthly bid-week price index. The right-most column in Table D2 shows that the percent difference between compensation figures varies considerably from month-to-month, which is largely a feature of the lagged movement of the monthly index compared to the daily index but may also be due in part to the regional vs. aggregated price difference. Across the year, however, there was less than a 1% difference in total MLCC payments calculated with the two indices, amounting to roughly $1,130,000.

Table D1 - MLCC at Monthly vs. Daily Spot Prices by Month.

Year.Month	MWh of Min. Load	MMBtu	MLCC - Monthly Gas Prc.	MLCC - Daily Gas Prc.	Difference
2003.01	73,675	959,813	$4,811,707	$5,044,371	4.6%
2003.02	60,470	792,982	$4,286,405	$4,912,286	12.7%
2003.03	70,579	1,142,377	$8,732,355	$6,163,414	-41.7%
2003.04	64,897	981,437	$5,364,107	$5,178,328	-3.6%
2003.05	46,731	714,313	$3,810,800	$4,217,490	9.6%
2003.06	108,472	1,630,988	$9,594,072	$9,423,332	-1.8%
2003.07	181,092	2,522,880	$14,422,472	$13,375,088	-7.8%
2003.08	290,459	4,166,981	$20,588,662	$22,214,428	7.3%
2003.09	180,479	2,618,038	$13,698,606	$13,024,430	-5.2%
2003.10	223,049	3,114,549	$15,227,582	$15,420,060	1.2%
2003.11	163,998	2,249,810	$10,796,221	$10,732,768	-0.6%
2003.12	212,149	2,681,011	$13,656,350	$16,413,072	16.8%
Totals	1,676,050	23,575,182	124,989,340	126,119,066	0.9%

[1] *See* Report on Natural Gas and Electricity Price Indices, Dockets No. PL03-3-004 and No. AD03-7-004 (issued May 5, 2004) at 60. This report is available on the Commission's Web site.

[2] *Id* at 10-15.

Attachment D

The estimated impact to total (MLCC) costs is relatively small across all units compensated for their minimum load in 2003. Table D2 below shows how individual participants are impacted by the move from the aggregated monthly bid-week index to the regional daily index.

Table D2 - MLCC at Monthly vs. Daily Spot Prices by Participant (2003 data - positive value denotes gain from moving to daily spot prices).

	Change from Moving to Daily Spot Gas Price	
Participant	**Percent**	**Dollars**
A	3%	$1,898,011
B	6%	$241,324
C	2%	$110,530
D	1%	$62,353
E	28%	$39,398
F	53%	$16,995
G	7%	$4,358
H	11%	$2,310
I	12%	$775
J	2%	$532
K	0%	$0
L	-5%	-$437
M	-12%	-$1,699
N	-4%	-$2,141
O	-2%	-$26,285
P	-3%	-$1,216,299

It is apparent that not all participants are expected to benefit from the change in price indices. However, even the largest dollar-value loss of -$1.2 million (Participant P) is only a 3% loss in MLCC payments when compared with their actual total MLCC payments for 2003.

ATTACHMENT E

Attachment E
Proposal for classifying units for local/Zonal/system requirements

Local Reliability Requirements

A unit will be classified as committed or operated for **local reliability requirements** when it is committed or operated to:

1. maintain power flows on a transmission component that is not part of a transmission path between Congestion Zones;
2. maintain acceptable voltage levels at a network location that is not part of a transmission path between Congestion Zones;
3. accommodate the forced or scheduled outage of a network component that is not part of a transmission path between Congestion Zones.

Under the current congestion management model, there may be more than one Participating TO ("PTO") within a Congestion Zone. This fact could greatly complicate the allocation of costs for local reliability requirements. Consider the following scenarios:

1. A unit located in PTO A's service area is operated to manage overloads on a transmission line within PTO B's service area. In this situation, the costs are probably most fairly allocated to PTO B even though the unit operating to manage the overload is in PTO A's service area.
2. A unit located in PTO A's service area is operated to manage overloads on a transmission line between PTO A and PTO B's service area. In this situation, the costs are probably most fairly allocated to both PTO A and B.
3. PTO B takes a transmission line out of service that creates overloads on a line in PTO A's service area. Though the overload is in PTO A's area, the overload was precipitated by PTO B's action. To whom should the costs be allocated? Does it matter whether the unit operated to manage the overload is in PTO A's area or in PTO B's area?

To simplify the allocation of minimum load costs associated with local reliability, the ISO recommends that the minimum load costs be allocated to the Participating Transmission Owner in whose service area the unit is located. The ISO acknowledges that, as shown in the examples above, the simple method of allocating costs to the Participating TO in whose service area a unit is located may not capture those situations in which, in theory, a more complex and precise allocation would allocate those costs to a different Participating TO or allocate the costs to both Participating TOs. However, allocating costs to multiple Participating TOs creates a cascading complexity: on what basis are the costs shared? On demand? On ownership rights?

The ISO believes that allocating costs to the Participating TO in whose service area the unit is located is equitable and proper in the vast majority of situations. This is, in fact, the method that has been approved for allocating

Reliability Must-Run costs (see Section 5.2.8 of the ISO Tariff). The ISO believes that creating complicated allocation rules to deal with the likely small number of exceptions to this method is unwarranted.

In sum, where a unit has been committed to meet local reliability requirements as set forth in the three principles above, the ISO recommends that the costs of that unit be allocated to the Participating TO in whose PTO Service Territory the unit is located.

Incremental Cost of Local Reliability

Southern California Edison (SCE) asked that where a unit is committed for local reliability requirements, and that unit also meets some overall system need, that the ISO allocate only the incremental costs of committing that particular unit (i.e., the costs of that particular unit above the costs of the cheapest available unit) to the Participating TO.

To do what SCE asks, the ISO will have to run the Unit Commitment ("UC") application twice. First, the ISO will determine what units must be committed to meet local reliability needs, manually "flag" those units as required, and run the UC application based on the ISO demand forecast and system requirements to obtain a total "extra-market" unit commitment cost. Next, the ISO will have to turn off any units manually flagged as needed for local reliability requirements and re-run the UC application using the same ISO demand forecast and system requirements to obtain an unconstrained, total "extra-market" unit commitment cost. If the units committed in the first UC run for local reliability requirements are not the cheapest units to be committed for system needs, the UC application will commit different, less expensive units in the unconstrained run. The difference between the cost of the first run and the second run represents the costs that the ISO will pass to local Participating TOs; the commitment costs determined in the second unconstrained run will be allocated as a system requirement.

At this time, the ISO believes it is possible to run the UC application twice and identify the incremental costs of local commitment. The ISO therefore proposes to implement SCE's request.

Zonal Requirements

A unit will be classified as committed or operated for **Zonal requirements** when it is committed or operated to:

1. maintain operations within the requirements of any nomogram that governs the operations of [an] inter-zonal transmission path(s);
2. maintain power flows on a transmission line that is part of a transmission path between Congestion Zones;

3. maintain acceptable voltage levels at a location that is part of a transmission path between Congestion Zones;
4. accommodate the forced or scheduled outage of a network component that is part of a transmission path between Congestion Zones;
5. provide Ancillary Services within a particular Zone, if the ISO is procuring Ancillary Services on a Zone-by-Zone basis.

Minimum load costs for Zonal requirements will be allocated to metered Demand and exports within the affected Zone.

System Requirements

A unit will be classified as committed or operated for **system requirements** when it is committed or operated to:

1. meet forecast Control-Area Demand;
2. provide Ancillary Services, if the ISO is procuring Ancillary Services on a control area-wide basis.

Minimum load costs for system requirements will be allocated first to Net Negative Uninstructed Deviation (up to a capped rate), then to ISO metered Demand and export.

Metered subsystems may have a different cost allocation than that described here – such as allocating any Must-Offer costs using Net Negative Uninstructed Deviation as the sole billing determinant, and never on the basis of metered Demand - which will be specified in the relevant MSS Agreement.

ATTACHMENT F

**NOTICE SUITABLE FOR PUBLICATION
IN THE FEDERAL REGISTER**

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

California Independent System Operator Corporation	))	**Docket No. ER04 - ____- 000**

Notice of Filing

[ ]

Take notice that the California Independent System Operator Corporation ("ISO") tendered for filing Amendment No. 60 to the ISO Tariff, for acceptance by the Commission. The ISO states that the purposes of Amendment No. 60 are to (1) propose the use of a Security-Constrained Unit Commitment ("SCUC") application to minimize must-offer commitment costs; (2) revise the gas cost proxy used in the Minimum Load Cost Compensation ("MLCC") payment and Start-Up payments; (3) include auxiliary power as a recoverable Start-Up cost; (4) eliminate the current practice of rescinding MLCC payments when a unit provides Ancillary Services; (5) revise the timing of the must-offer waiver denial process to facilitate bidding into the Day-Ahead Ancillary Services markets; (6) clarify Self-Commitment and its implications on MLCC payment; (7) revise how MLCC costs are allocated; and (8) establish a framework for using Condition 2 RMR Units outside of the Reliability Must-Run (RMR) Contract.

The ISO states that it has served copies of this letter, and all attachments, on the California Public Utilities Commission, the California Energy Commission, the California Electricity Oversight Board, on all parties with effective Scheduling Coordinator Service Agreements under the ISO Tariff, and on all parties on the official service list for Docket Nos. EL00-95 and EL00-98. In addition, the ISO is posting this transmittal letter and all attachments on the ISO Home Page.

The ISO is requesting that certain provisions of the amendment be made effective upon Commission approval, other provisions be made effective after Commission approval and upon ISO notice, while still other provisions be made effective when Phase 1B modifications are put into service.

Any person desiring to intervene or to protest this filing should file with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. All such motions or protests should be filed on or before the comment date, and, to the extent applicable, must be served on the applicant and on any other person designated on the official service list. This filing is available for review at the Commission or may be viewed on the Commission's web site at http://www.ferc.gov, using the **eLibrary** (FERRIS) link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, please contact FERC Online Support at FERCOnlineSupport@ferc.gov or toll-free at (866)208-3676, or for TTY, contact (202)502-8659. Protests and interventions may be filed electronically via the Internet in lieu of paper; see 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's web site under the "e-Filing" link. The Commission strongly encourages electronic filings.

Comment Date: ____________