UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation)	**Docket No. ER06-___-000**

PREPARED DIRECT TESTIMONY
OF
FARROKH RAHIMI

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Farrokh Rahimi. My business address is California ISO, 151 Blue Ravine Road, Folsom, California 95630.

Q. By whom and in what capacity are you employed?

A. I am the Principal Market Engineer within the Department of Market and Product Development at the California ISO.

Q. Please describe your professional and educational background.

A. I have 35 years of experience in the electric utility industry. I started my professional career at Systems Control, Inc., Palo Alto, CA, in 1970-72, where my assignments primarily involved utility projects. I then continued consulting, teaching, and research activities in the Middle East and Europe for 16 years, mainly working on electric utility industry projects, before returning to the U.S. in 1988 to work at Macro Corporation (now part of KEMA Consulting). I managed and technically contributed to energy planning and Energy Management System projects in the U.S., Canada, India, Egypt, Switzerland, and several other countries. With the advent of electric utility restructuring in the U.S., my main task at Macro Corporation was to adapt the design specifications of the Energy Control Center functions for the restructured utility environment. In 1996, while at KEMA Consulting, I was designated the project manager for the design and specification of the Bidding, Scheduling, and Settlement Systems for California ISO and California Power Exchange. The assignment was completed in early 1997, followed by implementation of the CAISO and PX systems. I joined the ISO Alliance as a contractor in mid-1997, and was part of the implementation team for CAISO and PX systems. In early 1998, I started my direct collaboration with CAISO as a contractor, and have since been fully engaged in the day to day operation of the CAISO. I have been part of the MRTU design team since its inception, as well as its predecessor projects, MD02 and CMR. I became a full-time employee of CAISO in September 2005. I have a Ph.D. in Electrical Engineering from Massachusetts Institute of Technology (M.I.T.), which I received in 1970.

My professional and educational background are described in further detail in the curriculum vitae provided as Appendix 1 to my testimony.

Q. Please describe your role in the development of the MRTU proposal.

A. I am a member of the MRTU design core team. I contribute to the design of the various MRTU features and functions, with a view to CAISO's operational needs, Market Participant requirements, and the requirements for efficient market operation. I also help design simulation studies to analyze the impact of different design approaches, help in the development of design requirements for software implementation, and help in the development of implementing tariff language. I have been a "Subject Matter Expert" contributor to the MRTU Tariff being filed.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony will discuss several of the main elements of the MRTU market design. In particular, I will focus on providing a clear understanding of how these often complex concepts will operate upon MRTU implementation. My testimony will provide an explanation of the following issues under the MRTU proposal: (1) the use of Locational Marginal Prices ("LMPs") in determining Energy prices paid to suppliers and charged to consumers, and in determining Congestion costs, (2) Congestion revenues and Congestion Revenue Rights ("CRR") settlements, (3) Ancillary Service ("AS") procurement, pricing, and cost allocation, (4) Residual Unit Commitment ("RUC") pricing, payment and cost allocation, (5) Uninstructed Deviation Penalties ("UDP") and (6) Resource commitment cost compensation. I will use simple examples to illustrate the underlying pricing, payment, and cost allocation mechanisms.

II. OVERVIEW OF MRTU MARKETS AND PRODUCTS

Q. What are the products transacted, priced, and settled in the Day-Ahead Market under MRTU?

A. The Day-Ahead Market ("DAM") under MRTU consists of the Market Power Mitigation and Reliability Requirements Determination ("MPM-RRD") process, the Integrated Forward Market ("IFM"), and the Residual Unit Commitment ("RUC") market. These markets span over all hours of the subsequent operating day. The IFM and RUC constitute the Day-Ahead settlement markets, *i.e.*, the markets that produce prices and quantities for which Market Participants are paid and charged.

The products transacted and priced in the IFM are Energy and AS. Congestion prices used for the settlement of CRRs and the reversal of Existing Transmission Contracts ("ETCs"), Transmission Ownership Rights ("TORs") and Converted Rights Congestion charges in IFM are also determined in this process. The CAISO is not the buyer of Energy in the IFM, but rather facilitates spot Energy purchases and sales in this market. In the IFM AS market, the CAISO acts as an agent to procure AS for those Market Participants who have not self-provided their AS obligations.

The sole product transacted and priced in the RUC market is RUC capacity. The CAISO runs the RUC process in the event the IFM did not commit sufficient resources to meet the CASIO Demand Forecast. The CAISO commits capacity under obligation to offer (capacity under Resource Adequacy contract), and to the extent necessary, may procure RUC capacity on behalf of those Market Participants who have underscheduled their load in the IFM.

The IFM is run simultaneously for all hours of the relevant operating day. Energy, AS, and Congestion clearing are performed simultaneously in this process. The RUC market is run after the IFM and has no impact on the IFM schedules and prices. However, Bids for Energy, AS, and RUC capacity (RUC Availability Bids) for all hours of the operating day must be submitted before the Day-Ahead Market closes at 10:00 a.m. the day before the relevant operating day, and may not be revised throughout the Day-Ahead Market processes, which as I mentioned is comprised of the MPM-RRD, IFM and the RUC market.

Q. What are the products transacted, priced, and settled in HASP under MRTU?

A. The products transacted, priced, and settled in HASP are Energy Imports and Exports and AS Imports. These include incremental AS purchases by the CAISO as compared to AS purchases in the IFM, and, if changes in forecasts or system conditions warrant, the buy-back of Import Energy sold in the IFM, or sell-back of Export Energy purchased from the CAISO in the IFM by Market Participants.

The HASP primarily is a scheduling process for the Real-Time Market. However, it also includes a competitive process to procure Energy and AS from resources outside the CAISO Control Area that are not dispatchable on an intra-hour basis. The competitive process in the HASP also allows the CAISO to procure Energy and AS from hourly Intertie Resources based on its Load forecast, while taking into account Real-Time Energy Bids from both internal resources and Imports and Energy Bids from Exports. In addition, internal generation resources may Self-Schedule changes to their IFM schedules in HASP. However, these schedules are part of the Real Time Market and will be settled at Real-Time prices rather than at HASP prices.

Q. What are the products transacted, priced, and settled in the Real-Time Market?

A. The products transacted, priced, and settled in the Real-Time Market are Energy and AS from internal Generation, and dynamically scheduled System Resources.

Generally, the CAISO will purchase its AS needs through the IFM, and will not defer these purchases until Real-Time. The CAISO will purchase Operating Reserves in Real-Time when the CAISO falls short of its WECC Minimum

Operating Reliability Criteria (MORC) Reserve requirements (due to forced outages, unanticipated changes in Load or system conditions, or prior Dispatch of Energy from AS capacity). The CAISO may also purchase additional Regulation services in Real-Time in order to contain the ACE (Area Control Error) in compliance with WECC and NERC Control Performance Criteria.

Q. What are the pricing and settlement intervals in the Day-Ahead Market, HASP, and Real-Time Market?

A. The IFM and RUC price calculations and settlement are performed on an hourly basis. HASP prices are also calculated on an hourly basis, but as the simple average of four 15-minute prices computed simultaneously at the pre-Dispatch time; HASP settlements are performed on an hourly basis. Real-Time pricing and settlement for AS is done quarter-hourly. Real-Time pricing for Energy is done on a 5-minute basis with settlement being conducted on a 10-minute basis for Dispatchable resources and an hourly basis for non-Dispatchable Loads. In addition, IFM, RUC, and Real-Time uplift payments, if any, are computed and settled daily with Supply and allocated on Settlement Interval basis to Demand.

III. USE OF LOCATION BASED MARGINAL PRICES

A. Nature and Properties of LMP

Q. What is LMP, and how is it related to Energy Bid prices?

A. Efficient resource scheduling and Dispatch is achieved by incorporating all resource and transmission constraints when matching electrical Supply to meet electrical Demand at least cost. The interplay of Energy Bid prices, transmission system bottlenecks (Congestion) and transmission system losses results in the generation of individual Market Clearing Prices at each location (node) in the CAISO's transmission network. The Locational Marginal Price (LMP) of Energy at a given network node is the marginal cost of serving Load at that node while respecting all Supply and transmission constraints.

Q. Can an LMP be computed only for nodes with associated Supply and Demand?

A. No. LMPs are not restricted to nodes that have Supply and/or Demand associated with them during a particular time period. The LMP for a node simply quantifies how much the overall (system-wide) least cost of meeting the Energy and AS Demand subject to transmission and resource constraints would increase ($\$\Delta$) if the Load at that node were increased by a very small amount (ε MWh). The resulting \$/MWh rate (Δ/ε) is the LMP at the node. Moreover, in order to determine the LMP at a network node, there is no requirement for Load to be connected to that network node (if there is no Load at the node, the Load is 0

MWh there). Under MRTU, LMPs are computed and published to the extent needed for Settlement Purposes.

Q. Under MRTU, what is the purpose of LMPs?

A. Under MRTU, LMP-based prices are used for payment to Energy suppliers and charges to Energy consumers. Under MRTU, accepted Energy Supply from internal resources, System Resources (Imports and Exports), and Energy purchase/sale by Participating Loads are paid or charged the LMP at the relevant resource, Intertie Scheduling Point, or Participating Load locations. Some Supply resources are scheduled or Bid as aggregate resources (e.g., Physical Scheduling Plants) and are paid commensurate weighted average LMPs (weighted by relevant nodal MW quantities). A single network node or a set of network nodes where physical injection or withdrawal is modeled and for which a LMP is computed and used for settlements is called a Pricing Node (PNode). Internal Loads are charged Load Aggregation Point ("LAP") prices, which are computed as the nodal Load weighted average of LMPs for the relevant Load aggregation zone, such as the corresponding Investor Owned Utility ("IOU") service territories. LAPs may be defined for non-IOU Demand as well. For example the Metered Subsystems (MSS) may have MSS-specific LAPs. However, the three LAPs based on the IOUs' service territories will be the Default LAPs under MRTU. Each of these will have their respective LMPs computed as weighted average of the LMPs at their constituent nodes. A detailed discussion of LAPs is contained in the testimony of Dr. Lorenzo Kristov.

Q. Do all Supply and Demand Bids that clear the market impact the LMPs?

A. LMPs can be set by both Supply and Demand Bids. However, only the Bids that are unconstrained at the optimal (system-wide least cost) solution can set the LMPs.[1] For example, a Generator that is constrained to be on due to its minimum run time and is operating at its minimum operating point, or a Generator that is ramping up or down and is constrained by its maximum ramp rate, or a unit that is constrained at its maximum operating point, will not be eligible to set the LMP. Excepting such cases, the LMP at a node is no less than the highest Supply Energy Bid price accepted at that node (if any) and no higher than the lowest Demand Energy Bid price accepted at that node (if any). This is true regardless of transmission network Congestion and Transmission Losses. This is why LMPs are used for payment and charges to Supply and Demand.

Accepted Bids that cannot set the price (due to their own physical limitations as stated above) are, however, eligible for uplift payments to ensure they are made whole to the extent the market revenues for the resource in question during the

[1] If a Bid from an otherwise constrained resource is eligible to set the LMP, the resource will be treated by the CAISO as an unconstrained resource for price determination. This will allow, under certain circumstances, Constrained Output Generators ("COGs") to set the price. This topic is addressed in detail in the testimony of Dr. Kristov.

corresponding operating time (e.g., the operating day) falls short of covering the Bid cost of the resource over the same period. I discuss this concept in greater detail later in my testimony, in the section devoted to the issue of Bid Cost Recovery.

Q. Does the fact that Bids are subject to hard caps under MRTU mean that LMPs will not exceed the Bid cap?

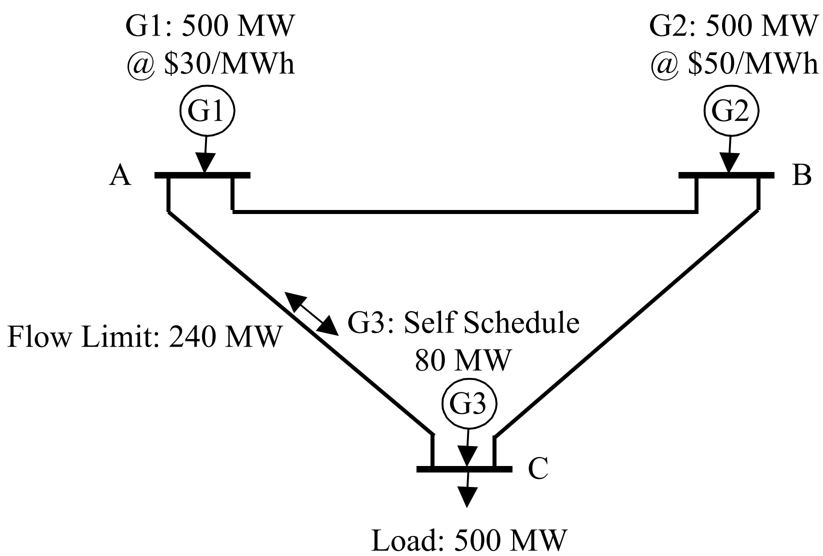
A. No. The LMP at a location may exceed the highest accepted Bid price, exceed the Bid cap, fall below the lowest accepted Bid price, or go below the Bid floor. All such situations may happen with all Bid prices between the Bid cap and the Bid floor.

Q. Could you illustrate, by way of an example, how the LMP could exceed the highest accepted Bid price?

A. Yes.

Example III.1:

Consider a three-node three-line network, with Generation at nodes A, B and C, and Load at node C.



Generation capacities and Bids are as follows: G1 = 500 MW Bid @ $30/MWh at node A, G2 = 500 MW Bid @ $50/MWh at node B, and G3 = 80 MW Self-Scheduled (price taker) at node C. The Load at node C is 500 MW and is Self-Scheduled (price taker). Thus, the net Demand at node C is 420 MW. The three transmission lines are assumed to have no losses and have identical impedances. Line A-C has a transmission limit of 240 MW.

Note that for every MW generated from G1 to serve the Load, 2/3 MW will flow on line A-C, whereas for every MW generated from G2 to serve the Load, 1/3 MW will flow on that line. These fractions (2/3 and 1/3) that state how much power will flow on a path in a given direction as a result of injection of 1 MW at a node and withdrawal at another (usually a reference node) are called Power Transfer Distribution Factors (PTDFs) or shift factors. In the absence of transmission constraints, the least cost solution to meet the 420 MW net Load at C would have been to generate 420 MW from G1. That would have resulted in a flow of (2/3)*420=280 MW on line A-C, which exceeds the 240 MW limit. To ensure the flow on line A-C does not exceed the 240 MW limit, the least cost solution is to schedule G1 at 300 MW and G2 at 120 MW. The flow on A-C will then be 2/3*300 + 1/3*120 = 240 MW.

The Locational Marginal Prices (LMPs) resulting from this "optimal" solution are $30/MWh at node A, $50/MWh at node B, and $70/MWh at node C. This is because the LMP at each node is the cost of serving an increment of Load at that node. It is clear that the cost of serving one more MW of Load at node A is $30 and at node B is $50. Regarding node C, note that to serve one more MW of Load at node C from either G1 or G2 would increase the flow on line A-C and violate the 240 MW flow limit. The least cost way to serve one more MW of Load at node C without violating the transmission constraint on line A-C would be to increase G2 by 2 MW and reduce G1 by 1 MW. This will result in a net of 1 MW (to serve the increment of Load), with a net effect of -1*(2/3) + 2*(1/3) = 0 MW on the flow on line A-C. The net cost to serve the incremental MW of Load at C is thus 2*$50 – 1*$30= $70. The LMP at node C is therefore $70/MWh, which is higher than the Bid prices from both G1 and G2.

Q: Could you illustrate, by way of an example, how the LMP could exceed the Bid cap?

A: Yes.

Example III.2:

With a Bid cap of $500/MWh, assume that in Example III.1 the Bid price of G2 is changed from $50/MWh to $300/MWh. The LMP at node C would then be 2*$300 - $30 = $570/MWh, which is higher than the Bid cap.

Q: Will the CAISO actually pay Supply and charge Load at prices higher than the Bid cap?

A: The answer is "yes" with an explanation. In Example III.2, G3 would be paid the LMP at node C, which is $570/MWh ($570*80 = $45,600), and the Load at node C would be charged at the same price ($570*500=285,000). Note that G1 and G2 would be paid their respective nodal prices, *i.e.*, $30*300=$9,000 and $300*120=$36,000 respectively. The difference between the net charges and payments for all 3 nodes would be $285,000 – ($45,600+$ 9,000 + $36,000) = $194,400.

An explanation is in order here regarding the price charged to the Load. The Load in the example is at a single node and not representative of the LAPLLoad that is cleared in the CAISO market. The latter is spread over a large area and the probability of such an outcome is very remote, since it would mean a poorly designed infrastructure (Generation and Transmission). However, such an outcome (prices above the Bid cap charged to the Load) is quite possible for custom Load that opts out of LAP pricing and is settled at the relevant nodal LMP. Also, a factor to consider with the existing LAPs is that their Interconnection with large sources of Supply in the WECC at large are radial as modeled in the existing MRTU network model. The price augmentation illustrated in the example is a phenomenon related to looped network models. If in the future the CAISO moves to more granular LAPs, that are interconnected by CAISO's internal looped network, such phenomena may occur at the small LAP levels. However, LAP Load can Bid a price in the IFM, and limit its exposure there (by economically shifting some of its purchase to Real-Time). Of course short of Demand-Side Management, the LAP Load would have nowhere to go in the Real-Time market, and could be exposed to high prices there. Long-term contracting strong physical Resource Adequacy would minimize the probability of such occurrences.

Q: Why is there net collection, that is, what is the reason for the $194,400 difference between charge to Load and payment to Generators?

A: This difference is due to Congestion on line A-C. In fact, this net collection is exactly equal to what is known as the "shadow price" of the constraint on line A-C multiplied by the flow on line A-C. The shadow price of the flow constraint on line A-C is the reduction in the total cost as a result of an incremental relaxation of the constraint (or increase in the capacity of line A-C). Note that 1 MW increase in the capacity limit on line A-C would allow the displacement of 3 MW of more expensive G2 Generation by 3 MW of less expensive G1 Generation. This is because such a shift will increase the flow on line A-C by 3*(2/3)-3*(1/3) = 1 MW. The net cost reduction is thus 3*$300-3*$30 = $810. Thus, the shadow price of Congestion on line A-C is $810/MWh. The Congestion rent associated with this constraint is thus $194,400 ($810*240=$194,400).

Q. What does the CAISO do with the Congestion rents it collects?

A. The Congestion rents collected by the CAISO form the source of funds for payment to the transmission rights holders (with any excess paid to transmission owners to offset their Transmission Revenue Requirements). More details concerning these payments will be provided in response to related questions later.

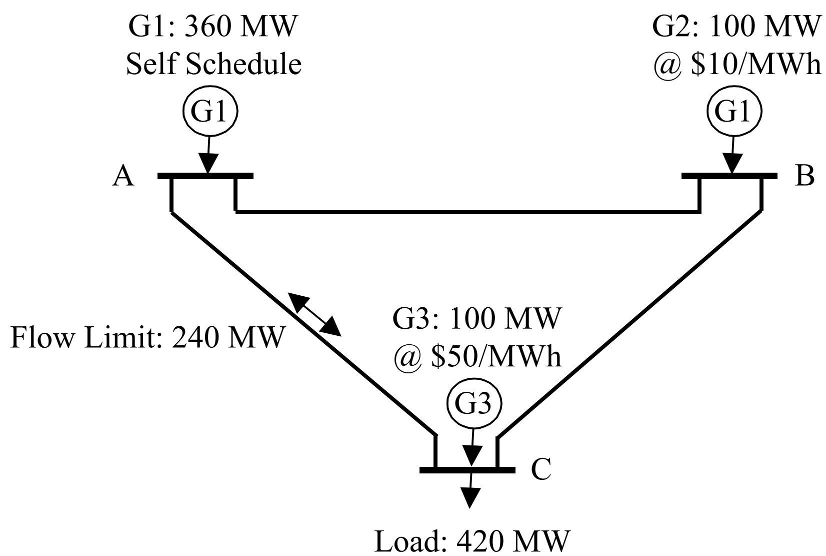
Q. Could you illustrate, by way of an example, how the LMP could be lower than the lowest accepted Bid price?

A. Yes.

Example III.3:

Consider a three-node, three-line network, with Generation at nodes A, B and C, and Load at node C. Generation capacities and Bids are G1=360 MW Self-Scheduled (price taker) at node A, G2=100 MW Bid @ $10/MWh at node B, and

G3=100 MW Bid @ $50/MWh at node C. The Load at node C is 420 MW and is Self-Scheduled (price taker). The three transmission lines are assumed to operate without losses and have identical impedances. Line A-C has a transmission limit of 240 MW.



The self-scheduled Generation of 360 MW at G1 results in the flow of 360*2/3 = 240 MW on line A-C. Thus, the only way to serve the Load at node C is to generate 60 MW from G3. The cheaper Supply of $10/MWh at node B cannot be used.

The LMP at each node is the cost of serving an increment of Load at that node. Obviously, the LMP at node B is $10/MWh and the LMP at node C is $50/MWh. Regarding node A, 1 MW Load at node A would reduce the net Generation at A by 1 MW, and the flow on line A-C by 1*2/3=2/3 MW, allowing 2 MW of Generation from the cheaper G2 Generation (because an increase of 2 MW from G2 would result in 2*1/3 = 2/3 flow on line A-C filling the space created by the 1 MW Load at A). This allows serving the incremental Load of 1 MW at A and replacing 1 MW of the more expensive G3 Generation with the cheaper G2 Generation. The net cost of serving 1 MW of Load at node A is thus 2*$10 - 1*$50 = -$30. The LMP at A is thus -$30/MWh.

Q: Will the CAISO actually charge the Supply at node A?

A: Yes. In the example just discussed, G1 will be charged $30*360 = $10,800 rather than receiving a payment.

The underlying phenomenon that explains the negative LMP in Example III.3 is that G1 is a "Generation pocket." In fact, this example points out a fundamental paradigm change from the current market design to the MRTU market design. Assuming that line A-C is an intra-zonal path, G1 could schedule even more than 360 MW and clear the forward market under the pre-MRTU paradigm, and then submit a "DEC" Bid to resolve Congestion on the line A-C in Real-Time. Because of its location, it could submit DEC Bids just above -$30/MWh and outbid DEC Bids of up to +$10/MWh at location B (which could be an Intertie Scheduling Point). The CAISO has observed such hypothetical behavior (known as the "DEC game") in actual practice under the current zonal market design in

California. Enforcing the A-C constraint when clearing the forward market, which will occur under MRTU, will discourage such behavior because of the negative LMPs that result from the interplay between Bids, schedules, and transmission constraints under such scenarios.

Q: What is the net collection by the CAISO due to Congestion in this example?

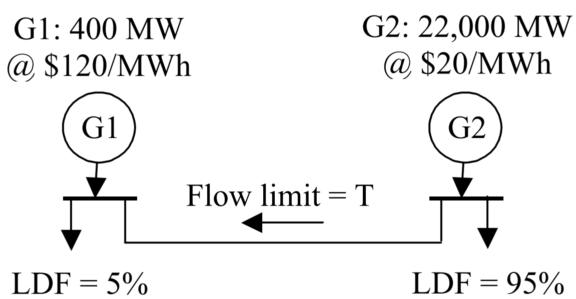
A: In this case G3 receives a payment of $50*60 = $3,000, the Load is charged $50*420 = $21,000, and G1 is charged $10,800, resulting in a net collection (by the CAISO) of $28,800. This collection is exactly equal to the Congestion rent associated with the constraint on line A-C. The shadow price of the A-C constraint is $120/MWh, because a 1 MW increase in the A-C limit allows for the displacement of 3 MW of G3 Generation by 3 MW of the cheaper G2 Generation, with an associated cost reduction of $50*3 - $10*3 = $120. The Congestion rent associated with line A-C is thus $120*240 = $28,800, which equals the net amount collected by the CAISO.

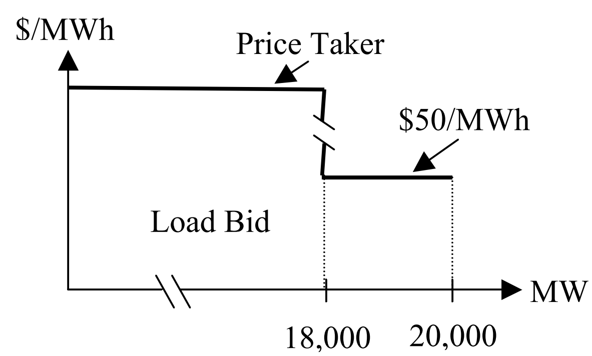
Q: In the above examples Load was always price insensitive. You mentioned that Load at the Load Aggregation Point (LAP) could also Bid a price. Can you provide an example to illustrate this?

A: Certainly.

Example III.4:

Consider the two-node one-line network with Generation sources G1 at node 1, G2 at node 2, and Load Aggregation Point (LAP) Load with Load Distribution Factors (LDFs) of 5% at node 1 and 95% at node 2. Generation at node 1 is limited to 400 MW and its Bid price is $120/MWh. There is significantly more Generation (22,000 MW) at node 2, at a Bid price of $20/MWh. The LAP Load is 20,000 MW with 18,000 Self-Scheduled (price taker) and 2,000 MW Bid at $50/MWh. The transmission line between nodes 1 and 2 is assumed to be lossless for simplicity, but has a transmission limit of T <= 700 MW in either direction.





Note that the relationship between the LMPs at nodes 1 and 2 and the LAP LMP is 0.05*LMP1 + 0.95*LMP2 = LMPLAP. Because G2 represents the low cost Supply, the least cost solution is to maximize Generation from G2 without violating the transmission constraint.

The solution to this problem must thus satisfy two conditions:

(a) The transmission flow limit T must not be violated.

(b) If the total Load served is more than 18,000 MW, the LMPs at nodes 1 and 2 must satisfy the relation (0.05*LMP1) + (0.95*LMP2) <= $50.

Case 1: The transmission limit is 700 MW

In this case all 20,000 MW of Load can be served without violating the transmission limit. The distributed Load at node 1 is 0.05*20,000 = 1,000 MW and the distributed Load at node 2 is 0.95*20,000 = 19,000 MW. Due to the transmission constraint, only 700 MW of Load at node 1 can be served from G2, and the remaining 300 MW must come from the higher cost G1 Generation source. Thus G1 is scheduled at 300 MW and G2 at 19,700 MW. The resulting LMPs are LMP_1=\$120/MWh and LMP_2=\$20/MWh. The LAP LMP is the cost of serving one more MW of LAP Load, i.e., 0.05 MW at node 1 and 0.95 MW at node 2, at a cost of 0.05*$120 + 0.95*$20 = $25/MWh, which is well below the $50/MWh LAP Load Bid price.

Note also that the shadow price of the Congestion constraint is ($120-$20) = $100/MWh resulting in a Congestion rent of $100*700=$70,000, which is exactly equal to the difference between the charge to Load ($25*20,000 = $500,000) and the payments to the Generators: ($120*300 + $20*19700 = $430,000).

Case 2: The transmission limit is 550 MW

Since the maximum Generation from G1 is 400 MW, in this case, only 950 MW of Load at node 1 can be served at any price without violating the transmission constraint. Because the Load at node 1 is 5% of the LAP Load, the LAP Load served at any price is thus 950/0.05 = 19,000 MW. G2 is therefore scheduled to serve the balance of the LAP Load not served by G1, *i.e.*, 19,000 – 400 = 18,600 MW.

Because not all LAP Load is served, the LAP Load sets the LAP LMP at \$50/MWh. Since $0.05*LMP_1 + 0.095*LMP_2 = LMP_{LAP}$, and LMP_2 = \$20, this results in LMP_1 = (\$50 – 0.95*\$20)/(0.05)=\$620/MWh.

Note that another way to compute LMP_1 is to calculate the shadow price of the transmission constraint. An increase of 1 MW in the transmission constraint would allow 1 more MW of Load at node 1, and thus 20 more MW of LAP Load to be served. Since the LAP Load values Energy at \$50/MWh, the "cost" reduction is the difference between the increased value to the LAP Load (\$50*20 = \$1,000) and the cost of serving the 20 MW of LAP Load. Because all 20 MW will be served from G2, the latter is \$20*20 = \$400. The net cost reduction resulting from 1 MW incremental transmission capacity is thus \$1,000 - \$400 = \$600. In other words, the shadow price of the transmission constraint in this case is \$600/MWh. Because the network is radial, this is the difference between the LMPs at nodes 1 and 2, which results in LMP_1 = \$600 + \$20 = \$620/MWh.

Case 3: The transmission limit is 450 MW

Because the maximum Generation from G1 is 400 MW in this case, only 850 MW of Load at node 1 can be served at any price without violating the transmission constraint. Because the Load at node 1 is 5% of the LAP Load, the LAP Load served at any price will be 850/0.05 = 17,000 MW. G2 is thus scheduled to serve the balance of the LAP Load not served by G1, i.e., 17,000 – 400 = 16,600 MW.

Because the amount of LAP Load served is in the non-economic range (below 18,000 MW), the LAP LMP is set at the relevant Bid cap (\$500/MWh). Note that LMP_2 is \$20/MWh, but LMP_1 is not set by either G1 or G2. Because (0.05*$LMP_{1)}$ + (0.095*LMP_2) = LMP_{LAP}, it follows that LMP_1 = (\$500 – 0.95*\$20)/(0.05) =\$9,620/MWh.

Q. Do you expect such high LMPs to result from the LAP Clearing approach in practice?

A: The LAP clearing mechanism CAISO has adopted is already in place at NYISO, and I have not seen any reports of such an outcome in practice. But, I would not rule out the possibility under "perfect storm" conditions, e.g., inadequate local Supply compounded with sever transmission derate and inaccurate LDFs; i.e., LDFs that fail to recognize the fact that under such conditions, interruptible Loads may be called upon in the local Load pocket.

Q: Will Generator G1 be actually paid the price of $9,620/MWh in such a case?

A: Yes, if the underlying reason is truly Supply scarcity. However, if the phenomenon responsible for this outcome is either Supply Bid insufficiency, or unduly restrictive transmission constraint not warranted for reliable system operation, or if the underlying LAP Load Distribution Factors (LDFs) are not realistically correlated, the CAISO will follow a market run "results verification" procedure, and if warranted re-run the market.

Q: Please explain how the verification process will work in such cases.

A: To the extent the CAISO cannot resolve a non-competitive transmission constraint utilizing effective economic Bids such that Load at the LAP level in the Day-Ahead Market, pre-IFM Pass 2, would otherwise be adjusted to relieve the constraint, the CAISO will have the authority under the MRTU Tariff to take the following actions in sequence:

1) The CAISO will schedule Energy from Self-Provided Ancillary Services Bids from capacity that is obligated to offer an Energy Bid under an abligation to offer Energy (*i.e.* RA and RMR). Since the otherwise Self-Provided AS capacity in question is under an obligation to offer Energy, the

associated Energy Bid prices will be either: a) submitted Energy Bids or b) Default Energy Bids to the extent an Energy Bid was not submitted for the Self-Provided capacity, but not lower than any Energy Bids from the same resource that may have cleared Pre-IFM Pass 1.

2) In case the measure in step 1 is insufficient to avoid adjustment of Load at the LAP level, the CAISO will evaluate the validity of the binding constraint and if it is determined that the constraint can be relaxed based on the operating practices, will relax the constraint consistent with operating practices.

3) In case the measures in step 1 and step 2 are insufficient, the CAISO may "soften" the LDF constraints on a nodal or sub-LAP basis, i.e., adjust Load at individual nodes or, in aggregate, a group of nodes to relieve the constraint to minimize the quantity of Load curtailed.

Q: Please explain how the first step of the above verification process will work.

A: Under the MRTU Release 1 design, in the Day-Ahead IFM, (as well as the Pre-IFM runs MPM-RRD) Self-Provided AS has a higher priority than serving Load. The right to Self-Provide Ancillary Services from capacity that is under a contractual obligation to provide Energy, including but not limited to capacity subject to an RMR Contract and local Resource Adequacy Resources, shall be conditional; self-provision of Ancillary Services from such capacity will only be permitted to the extent that capacity is not needed for Energy as a result of the MPM-RRD process described in this CAISO Tariff. Therefore, it may happen that the Self-Provided AS from capacity that is otherwise contracted to offer Energy prevents Energy from that resource to be used to resolve a local (non-competitive) constraint. This is a local Energy Bid insufficiency caused by Self-Provided AS. If the LAP Load is curtailed in Pre-IFM Pass 2 (where there is no Bid-in Load), the CAISO will treat Self-Provided AS from resources under contract obligation to offer as conditional to allow their Energy Bids (submitted or Default as the case may be) to resolve the local constraint. The AS Bid price for such conditional AS capacity will be set to the AS Bid floor to maximize the chances of this capacity to be used for AS in the Energy AS co-optimization process. The CAISO will then re-run the Pre IFM. To the extent the conditionally Self-Provided AS capacity is selected in the re-run of the Pre-IFM (i.e., not used for Energy), its Self-Provided AS status will be restored. The portion of the initially Self-Provided capacity that was incremented for Energy in Pre-IFM Pass 2 will be disqualified as Self-Provided AS and its Energy will be mitigated to the extent determined in the re-run MPM-RRD.

Q: Please explain how the second step of the above verification process will work

A: Relative priorities of enforcing transmission constraints or serving firm (vertical) Demand are "tuned" in the MRTU software. Moreover, transmission constraints enforced under the base case condition are tighter that those under contingency cases considered in the Security-Constrained Unit Commitment (SCUC). Relaxing the base case constraint to the less restrictive contingency constraint for the constraining local transmission path, may be operationally admissible since these constraints are not subject to the same level of scrutiny as the more important transmission corridors. Such adjustments will be made only to the extent needed to avoid LAP level Load curtailment in Pre-IFM Pass 2.

Q: Please explain how the third step of the above verification process will work

A: The third step is based on the recognition that fixed LDFs are responsible for large amounts of LAP level Load reduction due to small local Supply deficiencies. So the idea here is to allow some freedom for Load in different parts of the LAP to be adjusted within the confidence limits of the LDFs. The day-ahead LDFs are based on historical Loads patterns compiled by the State Estimator and smoothed over time for the relevant day type and time of use. In fact, the LDFs used in HASP/Real-time may be different from Day-Ahead LDFs because they are based on the most recent State Estimator runs at the time. So it is reasonable to allow some freedom within the confidence interval of the Day-Ahead LDFs. When such adjustments are made, the prices at the nodal or sub-LAP level should not fall below the cap, if there is true local Supply scarcity.

The MRTU software in Release 1 will not be equipped to automatically accomplish this step 3. However, the CAISO, in collaboration with the

Department of Market Monitoritng, is continuing to develop processes that will allow it to implement this last step, if or when it is needed. Such proceses would include monitoring and corrective measures through the use of non-production data processing routines or tools relying on data from the production software.

Q: How likely is the phenomenon illustrated in your example to occur in practice?

A: The phenomenon of LAP Load reduction and very high LMPs illustrated in the previous example is likely to occur in the case of local Supply Bid insufficiency in conjunction with local transmission derates. However, such an outcome will be highly unlikely if there is strong physical local Resource Adequacy.

Q: Will the charges to the Load in the previous example cover payment to the Generators in that example, despite the high Generation LMPs?

A: Yes. The difference between the charges to the Load and payment to the Generators in the previous example represents the Congestion rent. In this example, Load pays $500*17,000 = $8,500,000; Generation is paid $9,620*400 + $20* 16,600 = $4,180,000, and the difference, $4,320,000, is exactly equal to the shadow price of the transmission constraint multiplied by the line flow. The shadow price of the constraint in this case is $9,600 the line flow is 450 MW, and $9,600*450=$4,320,000.

Q: Do transmission losses impact the LMPs?

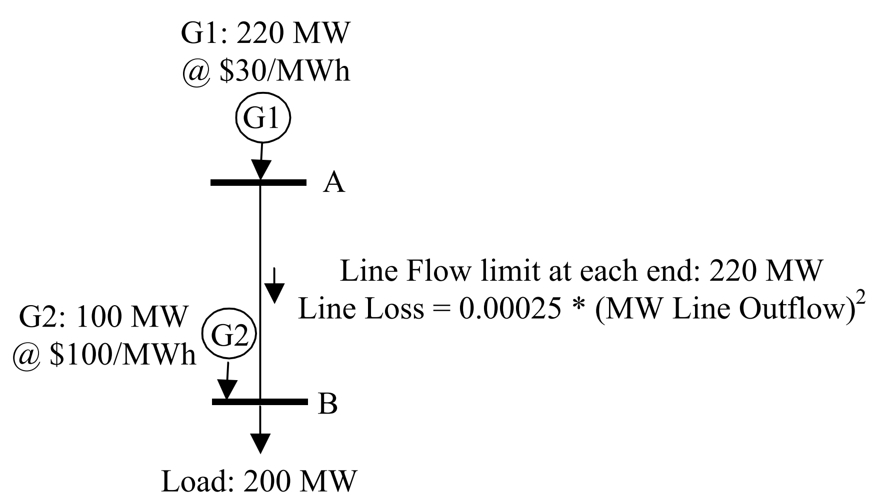
A: Yes. In the above examples, the transmission lines were assumed to operate without losses in order to simplify the computations. Transmission Congestion was the only factor in these examples that contributed to the difference in the LMP. Transmission losses can result in LMP differences with or without transmission Congestion.

Q: Could you illustrate how transmission losses result in LMP differences without any transmission Congestion being present?

A: Yes.

Example III.5:

Consider the following simple two-node, one-line network, with Generation at nodes A and B, and Load at node B.



Generation capacities and Bids are G1=220 MW Bid @ $30/MWh at node A and G2=100 MW Bid @ $100/MWh at node B. The Load at node C is 200 MW and is Self-Scheduled (price taker). Assume the line from node A to node B is unconstrained (has a rating exceeding 210 MW in this example) and its transmission losses are given by the formula $0.00025 * P^2$, where P is the outflow of the line (*i.e.*, line flow as measured at the receiving terminal of the line).

With the above data, if all Load is served from the cheaper Generation G1, there will be transmission losses of $0.00025*(200)^2 = 10$ MW. In that case G1 must generate 210 MW to both the serve the Load and provide for losses. The cost $30*210= $6,300 is far less than serving the Load from more expensive Supply G2 (which would entail no transmission losses, but would cost $100*200=$20,000).

The LMP at node A is obviously $30/MWh because that is the cost of serving one MW of incremental Load at A. Regarding node B, we note that an increase of 1 MW of Load at node B entails more than 1 MW incremental Generation from G1. In fact, changing the Loads from 200 MW to 201 MW and serving it all from G1, increases the transmission losses from 10 MW to $0.00025*(201)^2 = 10.1$ MW. Thus to serve more MW of Load at node B from G1 requires an incremental Generation of 1.1 MW at the cost of $30*1.1=$33 (which is still cheaper than serving the increment of Load from G2, with no increase in losses, at the cost of $100 MW). Thus the LMP at node B is $33/MWh.

Q: Will the CAISO pay the Supply and charge the Load based on these LMPs?

A: Yes. In the case just discussed, G1 will be paid $30*210 = $6,300, and the Load will be charged $33*200=$6,600. The difference between the net charges and payments is $6,600 - $6,300= $300.

Q: Why is there net collection, *i.e.*, what is the reason for the $300 difference between charge to Load and payment to Generators?

A: This is due to the fact that Marginal Losses are higher than average losses. In the above example, the increase in transmission losses caused by serving an additional 1 MW increment of Load was computed as 0.1 MW. This is an incremental (marginal) transmission loss of 10%. However, the average loss on line A-C is 10 MW/200 MW = 5%.

Q: What does the CAISO do with the surplus resulting from the difference between marginal and average loss charges?

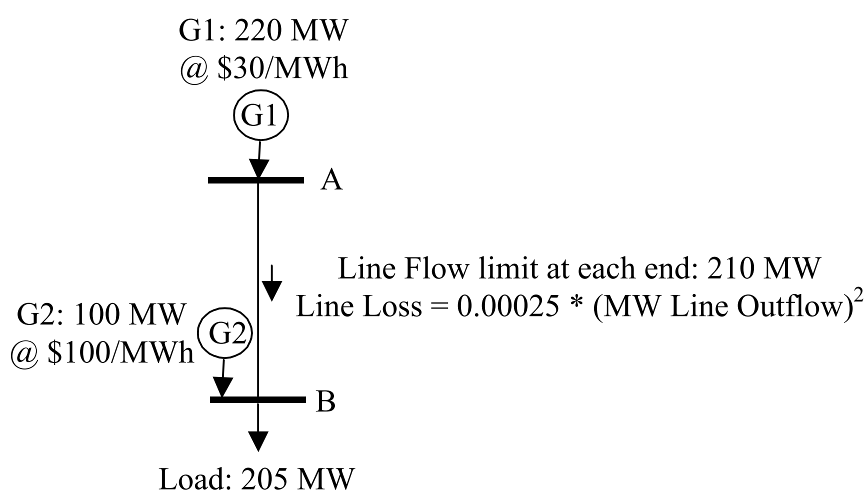
A: The CAISO will allocate these surplus amounts to Scheduling Coordinators during the relevant time periods based on metered CAISO Demand plus Real-Time Interchange export schedules (“Measured Demand”).

Q: **In the above example you assumed that there was no Congestion on the transmission line. Can you illustrate the computation of LMPs with both transmission Congestion and losses present?**

A: Yes.

Example III.6:

Assume that in Example III.5, the rating of the line from A to B is changed to 210 MW at each end, and the Load is 205 MW.



In the absence of the transmission constraint, the 205 MW of Load could be served by G1. However, that would require $205 + 0.00025*(205)^2 = 215.5$ MW from G1, which exceeds the 210 MW of line flow limit. The least cost solution, enforcing the transmission constraint, is to schedule G1 at 210 MW and G2 at 5 MW. Note that with G1 scheduled at 210 MW, the outflow on line A-B at B is 200 MW (and the losses are 0.00025*(200)2 = 10 MW as before). Thus 210 MW from G1 serves 200 MW of the Load (plus 10 Mw of losses) and the remaining 5 MW of Load is served from G2.

The resulting LMPs are $30/MWh at A and $100/MWh at B. The payments and charges are thus:

- Payment to G1: $30*210 = $6,300
- Payment to G2: $100*5 = $500
- Charge to Load: $100*205 = $20,500
- Net collection by the CAISO: 20,500 – ($6,300+$500 = $13,700.

Q: How does the CAISO determine what potion of the $13,700 is due to Congestion and what portion due to Marginal Loss surplus?

A: This is done by breaking down the LMPs into system Energy, Congestion and Marginal Loss components. I will discuss this process in detail in the following section.

B. <u>Components of LMPs</u>

Q. In your previous response, you stated that LMPs are made up of three components. What are the three components?

A. The LMP at any given node may be broken down into three components, namely:

- System Marginal Energy Cost component ("MEC");
- Marginal Congestion Cost component ("MCC"), and
- Marginal Loss Cost component ("MLC")

Q. Please explain the System Marginal Energy Cost component, and describe how it is determined.

A. For the sake of conceptual simplicity, the System Marginal Energy Cost (MEC) can be thought of as the marginal cost of serving Load (*i.e.*, the $/MWh cost of serving the next incremental MW of Load) anywhere on the system in the absence of Congestion and losses. This is, however, not correct technically. What is correct is the fact that the MEC is the same for all nodes in the network. In a more technical sense, the System Marginal Energy Cost is the sensitivity of the power balance constraint at the optimal solution. The power balance constraint ensures that the physical law of conservation of Energy (the sum of Generation and imports equals the sum of Loads, exports and transmission losses) is accounted for in the network solution. Because transmission losses are not known before determining the least cost solution, a so-called "slack" or "reference bus" is designated in the network solution to absorb any positive or negative power mismatch. Once the slack bus is selected, the LMP at that bus becomes the System Marginal Energy Cost. The Marginal Loss and Congestion components are zero at the slack bus.

Q. How is the slack bus determined?

A. There is no universal rule that determines the selection of the slack bus. The slack bus may be designated as a single node or a collection of nodes. The usual choices are a Generation node (with a large Generation capacity), the set of Generation nodes (referred to as distributed Generation slack), or the set of Load nodes (referred to as distributed Load slack). If a distributed slack option is selected, then the contribution of different nodes in the set to power balance mismatch correction is specified by the so-called "distribution factors." The use of distributed slack is now an industry standard, and thus for MRTU the distributed slack option will be employed.

Q. What is the significance of the choice of the slack bus?

A. The choice of the slack bus does not impact the LMPs, but does impact the repartition of the LMPs into the three components mentioned above.

The System Marginal Energy Cost is the same for all nodes in the network. When the LMPs are different at two nodes, such difference is due to the Marginal Loss and Marginal Congestion components of the LMPs.

Another way of viewing the System Marginal Energy Cost is as the price associated with transmission losses. To understand this concept, note that the algebraic sum of all MW injections (Supply and Demand at various nodes) system-wide is exactly equal to transmission losses. Thus, if all Energy purchases and sales were to be settled at the System Marginal Energy Cost, the result would be a net deficit for the CAISO equal to the MWh of losses multiplied by the

System Marginal Energy Cost. This is in contrast to the outcome of settlement based on full LMPs, wherein the Marginal Loss components of the LMPs results in a net collection by CAISO. However, because both the System Marginal Energy Cost and the Marginal Loss components of the LMPs depend on the choice of the slack bus, both the cost of losses and the marginal cost of losses are not meaningful in absolute terms. They can only be compared relative to each other on a system-wide basis.

Q. What is the Marginal Congestion Cost component of LMPs?

A. The Marginal Congestion Cost (MCC) at a node indicates how much the system-wide Congestion cost would change as a result of an incremental Load consumption at the node served from the reference or slack bus.

Q. Please describe how the Marginal Congestion Cost component of the LMPs is computed.

A. The Marginal Congestion Cost of the LMP at a given node is a linear combination of the shadow prices of all binding transmission constraints in the network, each multiplied by the negative of the corresponding Power Transfer Distribution Factor (PTDF), also known as the Shift Factor. The Shift Factor of a node with respect to a transmission path (and direction on the path) measures the change in the power flow through the path (positive or negative with respect to the designated direction on the path) as a result of a 1 MW incremental injection at the node balanced by incremental change of Load at the reference (slack) bus.

Q. Can you provide an example to illustrate Marginal Congestion Cost computation?

A. Yes. In doing so, I will revisit my first example (Example III.1):

We have already seen an example of shift factors in that example. Although not explicitly stated, the assumptions used in that example resulted in node C operating as the reference or slack bus. We computed the shift factors of nodes A and B with respect to line A-C (in the direction of A to C) as 2/3 and 1/3 respectively. The shift factor for node C is 0 because there is no change in the flow on any path if 1 MW is injected and withdrawn at node C.

In Example III.1, there was one binding transmission constraint (line A-C) with a shadow price of 3*($50 - $30) = $60/MWh. This is the value of the shadow price because an increase of 1 MW in the transmission capacity of line A-C (or relaxation of the constraint by 1 MW) would allow for the substitution of 3 MW of the more expensive G2 Generation (@ $50/MWh) with 3 MW from the less expensive G1 Generation (@$30/MWh). With node C as the slack bus, the Marginal Congestion Cost components (MCC) of the LMPs are thus $0/MWh at C, -2/3*$60 = -$40/MWh at node A and -1/3*$60 = -$20/MWh at node B.

Because the LMP at node C is $70/MWh, the System Marginal Energy Cost component (MEC) is $70/MWh for all nodes. The Marginal Loss Cost components (MLC) are $0, because losses were ignored in Example III.1. Note that the sum of the three components at each node equals the LMP at that node: $70-$40+$0 = $30 for node A, $70-$20+$0=$50 for node B, and $70+$0+$0 = $70 for node C.

Q. Is the Marginal Congestion Cost component always positive?

A. No. The Marginal Congestion Cost component may be positive or negative depending on whether incremental power consumption at the relevant node marginally increases or decreases the Congestion on the congested path(s). The choice of the reference (slack) bus, based on which shift factors are determined, may impact not only the magnitude, but also whether the Marginal Congestion Cost component of the LMP at a given node is positive or negative. However, if transmission losses are ignored, the Congestion cost associated with the injection at a node and withdrawal of the same quantity of power at a different node is generally not impacted by the change in the reference (slack) bus or the magnitude and sign of the individual shift factors.

Q. Can you provide an example to help demonstrate this?

A. Certainly.

Example III.7:

Consider Example III.1 again. Let us choose node B as the reference bus this time. To compute the shift factor of line A-C for Node A, note that a 1 MW injection at node A withdrawn at the reference bus (node B) would result in a flow of 1/3 MW on line A-C in the reference direction (A to C). Similarly, a 1 MW injection at node C withdrawn at node B would result in a flow of 1/3 MW on line A-C in the opposite direction to the reference direction (A to C). Thus, the shift factors of line A-C with node B as reference are +1/3 for node A and –1/3 for node C. The following table summarizes the shift factors for line A-C assuming different choices of the slack bus:

Line A-C Shift Factors with Different Choices of Slack Bus

	Node A SF	Node B SF	Node C SF
Node A Slack	0	-1/3	-2/3
Node B Slack	1/3	0	-1/3
Node C Slack	2/3	1/3	0

With node B as the slack bus, the MEC is \$50/MWh, and the MCCs are MCC_A = -1/3*\$60 = -\$20, MCC_B = \$0, and MCC_C = -(-1/3)*\$60 = +\$20.

The following Table summarizes the MEC and MCC components of the LMPs given the three different choices for the slack bus:

LMP Components with Different Choices of Slack Bus

	MEC	MCC_A	MCC_B	MCC_C
Node A Slack	$30	$0	+$20	+$40
Node B Slack	$50	-$20	$0	+$20
Node C Slack	$70	-$40	-$20	$0

Note that the MCCs change in both magnitude and sign with the change in the selection of the slack bus. However, the difference between the MCCs at any two nodes remains unchanged. For example, MCC_B - MCC_A = +$20/MWh regardless of the choice of the slack bus. Note, however, that this outcome is valid only in the absence of Marginal Losses. The difference between MCCs at two nodes may change with the selection of a different slack bus when both Congestion and losses are present.

Note also that the sum of the LMP components at each node is equal to the LMP at that node regardless of the choice of the slack bus. In this scenario, the MLCs are $0 because the network in Example III.1 was assumed to be lossless.

Q. What is the Marginal Loss Cost component, and how is it determined?

A. The Marginal Loss Cost at a node reflects the marginal cost of transmission losses associated with serving an increment of Load at that node. It is computed as the System Marginal Energy Cost multiplied by the Marginal Loss factor at that node. The Marginal Loss factor at a node is the incremental change in the quantity (MW) of transmission losses in the network for serving an increment of Load at the node from the slack bus (or busses). This is the case because the slack bus picks up the power balance mismatches and the System Marginal Energy Cost reflects the cost of Energy associated with the losses, as explained earlier.

Q. Is the Marginal Loss Cost component of the LMP always positive?

A. No. The Marginal Loss Cost (MLC) may be positive or negative depending on whether incremental power consumption at the relevant node marginally increases or decreases transmission losses. Also, the choice of the slack bus (or busses) may impact not only the magnitude, but also the sign, of the Marginal Loss Cost component of the LMP at a node. For example, as I stated earlier, the Marginal Loss Cost component of the LMP is $0 at the slack bus. If a different node is selected as the slack bus, the Marginal Loss Cost component of the LMP at the former node may no longer be $0 (*i.e.*, it may now be either positive or negative depending on the choice of the new slack bus).

Q. Could you please provide an example demonstrating how the Marginal Loss Cost component is determined?

A. Yes. Let us consider Example III.5, as discussed earlier.

Although I did not specifically say so, the situation presented in that Example assumed that node A was the reference bus for purposes of determining Marginal Losses. The MLC at node A is thus $0, and the MEC is$30/MWh. As we computed there, serving an incremental Load at node B from the reference (slack) node A would increase the transmission losses by 0.1 MW, thus the Marginal Loss factor for node B is 10%, and the MLC for node B is 10% of the MEC, i.e., $30*10% = $3/MWh. Note that there was no Congestion in Example III.5. Therefore, the MCCs are $0 for both nodes. The LMP at each node ($30 at node A and $33 at node B) is the sum of the MEC and the respective nodal MLC.

Q. What is the significance of the Marginal Loss Cost component of the LMPs?

A. Assume that Supply and Demand were both charged and paid based only on the Marginal Loss Cost components of their respective LMPs. Although, due to transmission losses, the quantity (MW) of Supply is more than Demand (due to transmission losses), the net system-wide collection by the CAISO resulting from such a hypothetical settlement would be positive, and in fact would exceed the deficit that the CAISO would incur as a result of paying for losses at the System Marginal Energy Cost price described earlier. This means that if the Marginal Congestion Cost component of the LMPs were ignored, and Supply and Demand were paid and charged only the sum of the System Marginal Energy Cost price plus their respective Marginal Loss Cost LMP components, there would be a net collection by the CAISO, which is referred to as the Marginal Loss surplus revenue.

Q. Please describe why there are Marginal Loss surplus revenues.

A. Transmission losses change roughly quadratically with power flow through a transmission path. Therefore, Marginal Losses are roughly twice average losses. Because the Marginal Loss Cost component of the LMP at a node is the System Marginal Energy Cost multiplied by the Marginal Loss factor at that node, the Marginal Loss surplus revenues exceed the average costs associated with transmission losses by an almost 2:1 ratio.

Q. Can you provide an example demonstrating how Marginal Loss surplus revenues are computed?

A. Yes. In Example III.5, we computed the Marginal Loss surplus ($300) for a simple case where there was no Congestion present. For the more complicated case of Example III.6 where there are both Congestion and losses, we computed the total surplus ($13,700) due to Congestion and losses, but did not attempt to partition this amount into its congestion and Marginal Loss surplus components. We will do that here.

Example III.8:

We will use the network and price data used in Example III.6 to illustrate the following facts:

- Although the choice of the slack bus for partitioning the LMPs does not change the LMPs, it does change the LMP components.

- The choice of the slack bus does not change the sum of the total Congestion rents and the Marginal Loss surplus system-wide. Thus, in the absence of Congestion, the system-wide Marginal Loss surplus does not depend on the choice of the slack.
- The choice of the slack may impact the apportioning of the total surplus (Congestion rents plus Marginal Loss surplus) between Congestion rents and Marginal Losses.

Let us re-visit Example III.6, and consider two cases, one with node A and the other with node B as the reference (slack) bus. Note that the LMP at node A is $30/MWh and the LMP at node B is $100/MWh. The Generation and Load quantities are G1 = 210 MW at node A, G2 = 5 MW at node B and Load = 205 MW at node B. Thus the total injection at node A is 210 MW, the net Load at node B is 200 MW, and the losses are 10 MW. The repartitioning of the LMPs into the MEC, MCC, and MLC components depends on the choice of the slack bus.

Case 1: LMP Components and Marginal Loss Surplus with Node A as the Reference (Slack) Bus

With node A as the reference, the system-wide component of the LMPs is $30/MWh, and the Congestion and Marginal Loss Cost components at A are both $0. The Marginal Loss factor for node B is 10%, as stated earlier, and the MLC of

B is $30* 10% = $3/MWh, which means the MCC at B is $100 - $30 - $3 = $67/MWh.

The LMP components are as shown below:

Node	MEC	MCC	MLC	LMP (total)
A	$30	$0	$0	$30
B	$30	$67	$3	$100

The charges and payments by the CAISO may be repartitioned based on the MEC, MCC, and MLC components of the LMPs as shown in the following table (charges are positive and payments negative). For instance, as shown in the first row the Supply at node A is paid for 210 MW at the MEC rate of $30/MWh. This is a payment (negative) of $30*210=$6,300; similarly the net Load of 200 MW at node B is charged at the MEC rate, for a net charge of $30*200=$6,000.

	Node A (Supply of 210 MW)	Node B (net Load of 200 MW)	Total
Energy	-$6,300	$6,000	-$300
Congestion	$0	$13,400	$13,400
Marginal Loss	$0	$600	$600
Total	-$6,300	$20,000	$13,700
Marginal Loss Surplus	-	-	$300

The As I explained previously, the Marginal Loss surplus can be computed in one of two ways (1) by subtracting the Congestion rents from the total surplus,

$13,700 - $13,400 = $300; (2) by subtracting he total payment for average losses (at the MEC rate) from total charges Marginal Losses. $600 – ($300)[2] = $300.

Case 2: LMP Components and Marginal Loss Surplus with Node B as the Reference (Slack) Bus

With node B as the reference, the system-wide component of the LMPs is $100/MWh, and the Congestion and Marginal Loss components at B are both $0. The Marginal Loss factor for node A is -10%, because serving 1 MW incremental Load at A from B would reduce the flow on line A-B and thus reduce the transmission losses by approximately 0.1 MW (10%). Therefore, the MLC of A is $100* (-10%) = -$10/MWh, which means the MCC at A is $30 - ($100) - (-$10) = - $60/MWh.

The LMP components are therefore as follows:

Node	MEC	MCC	MLC	LMP (total)
A	$100	-$60	- $10	$30
B	$100	$0	$0	$100

The charges and payments by the CAISO repartitioned based on the MEC, MCC, and MLC components of the LMPs are shown in the following table:

[2] As stated before the payment for average losses at the MEC rate is the same as the system-wide Energy revenue collection at the MEC rate (first row of the table). In fact the multiplying the losses (10 MW) by the MEC, we get $300, with a negative sign (payment), which is the same as the net collection (-$300) in the first row of the table.

	Node A (Supply of 210 MW)	Node B (net Load of 200 MW)	Total
Energy	-$21,000	$20,000	-$1,000
Congestion	$12,600	$0	$12,600
Marginal Loss	$2,100	$0	$2,100
Total	-$6,300	$20,000	$13,700
Marginal Loss Surplus	-	-	$1,100

Q. Although their sum is not changed, your example shows that the choice of the Reference Bus impacts the net system congestion revenues and the Marginal Loss surplus individually. Doesn't that mean that by changing the slack or Reference Bus the Congestion Revenues paid to CRRs may be impacted?

A. Yes. But I must explain this point further. The illustrations above were based on the use of a single slack bus. The derivations presented above were also simplified for ease of understanding, but the results do indicate the outcome of many commercially available software programs used to compute LMPs and the LMP components. As stated earlier, it is now an industry standard to use distributed slack, and that is also the approach the CAISO has adopted for its LMP computations. However, even with a distributed slack, if the distribution factors are changed, the same kind of outcome observed above (change of Congestion and Marginal Loss revenues relative to each other as a result of the change of the slack bus) may result, although the impact would be much smaller. The CAISO and its vendor are currently studying a new approach reported in the literature[3] that appears to retain the Congestion components of the LMPs invariant to the change of the slack distribution factors, and thus render the Congestion revenues independent of such choice. The initial review of this method, however, indicates that to achieve this result another set of factors, "loss distribution factors", are kept fixed. Now changing these "loss distribution factors" may have a similar effect as changing the slack bus distribution factors in the convectional industry approach. At any rate, the CAISO will be using a state of the art approach to insure stability of the LMP Congestion components that are the basis on which CRRs are settled, and ETC/TOR and Converted Rights Congestion charges are reversed.

Q. How does CAISO propose to distribute Marginal Loss surpluses?

A. Marginal Loss surpluses are accrued both in the Day-Ahead IFM market and in the HASP/Real-Time market. Pursuant to the filed MRTU design, the Marginal Loss surplus associated with HASP/Real-Time Congestion is included in the Imbalance Energy Offset, and allocated to Measured Demand (*i.e.*, metered CAISO Demand plus Real-Time interchange export schedules.

[3] Eugene Litvinov, Tongxin Zheng, Gary Rosenwald, and Payman Shamsollahi; "Marginal Loss Modeling in LMP Calculation"; IEEE Transactions on Power Systems, Vol. 19, No. 2, May 2004.

With respect to the Marginal Loss surpluses associated with the IFM, the CAISO initially proposed to deposit these Marginal Loss surpluses along with the IFM Congestion revenues in the CRR Balancing Account. To the extent funds were left in the CRR Balancing Account at the end of the annual CRR cycle, that balance would be paid to the PTOs to reduce the Transmission Access Charge (TAC) and the Wheeling Access Charge (WAC). This proposal was approved by the Commission in its October 28, 2003 Order, *California Independent System Operator Corporation*, 105 FERC ¶ 61,140 at P 77 (2003), and in its June 17, 2004 Order (*California Independent System Operator Corporation*, 107 FERC ¶ 61,274 at P 146 (2004).

At the MRTU stakeholder meetings held in Summer2005, however, many stakeholders expressed dissatisfaction with this approach. The main objection came from entities who were not beneficiaries of the CRR Balancing Account (primarily the ETC and TOR holders). Others noted concern with the long time delay between the assessment of Marginal Loss charges and the ultimate true-up through TAC/WAC reduction by virtue of the funds left over in the CRR Balancing Account at the end of the year.

In response to this feedback, the CAISO revised its initial proposal, and now proposes to allocate the Marginal Loss surpluses to Control Area Metered Demand, in the same manner as it will allocate the HASP/Real-Time Marginal

Loss surpluses. This proposal will satisfy the concerns expressed by stakeholders because it will result in all Scheduling Coordinators (including ETC/TOR holders) receiving a share of the refunds for excess losses, and those refunds will be distributed faster and more frequently.

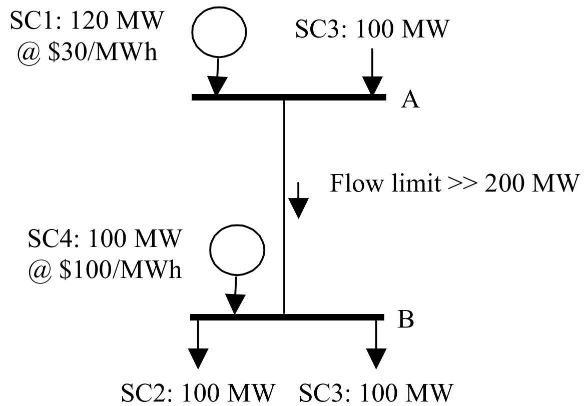
Q. Were there any other concerns raised by stakeholders with respect to the allocation of Marginal Loss surpluses?

A. Yes. Several entities expressed a desire for the CAISO to individually compute and rebate their Marginal Loss surpluses. The CAISO, however, does not believe that this alternative is appropriate, for the following reasons. The following example demonstrates this problem even in the simple case where there is no congestion.

Example III.9:

Consider our earlier Example III.5 gain. Assume the line from A to B is unconstrained and its transmission losses are given by the formula 0.00025 * P^2, as stated in that example. Assume there are four Scheduling Coordinators:

- SC1 submits Supply Bid of 120 MW @ $30/MWh at A.
- SC2 submits 100 MW of Load at B as price taker.
- SC3 submits 100 MW injection at A and 100 MW of Load at B both as price takers (balanced schedule).
- SC4 submits Supply Bid of 100 MW @ $100/MWh at B.



With the above data, all Supply is Dispatched from SC1's Generation (which is scheduled at 110 MW); SC4's Supply is not Dispatched. There is no congestion, and the losses are $0.00025*(200)^2 = 10$ MW. As in Example III.5, the LMPs at nodes A and B are $30/MWh and $33/MWh respectively. The system-wide $ amount of surplus due to Marginal Loss pricing is: $33*200 - $30*210 = $300. Since the total LMPs are independent of the choice of the reference, in the absence of congestion this surplus $ amount is also independent of the choice of the reference bus for determining Marginal Loss components of the LMPs. However, the presumption as to which SC was overcharged and by how much depends on the choices of the reference as shown below.

Case 1: Marginal Losses and Marginal Loss Payments with A as the Reference

With node A as the reference, the system-wide component of the LMPs is $30/MWh, and since there is no congestion, the congestion components of the LMPs are $0. The LMP components are as shown below:

Node	LMP (sys)	LMP (cong)	LMP (loss)	LMP (total)
A	$30	$0	$0	$30
B	$30	$0	$3	$33

The total payments and presumed payments for Marginal Losses by different SCs are:

SC	MW Withdrawal at A	MW Withdrawal at B	Total Charge to the SC	Presumed Marginal Loss Charge to the SC
SC1	-110	0	- $3,300	$0
SC2	0	100	$3,300	$300
SC3	-100	100	$300	$300
SC4	0	0	$0	$0
Total	-210	200	$300	$600

The cost of average losses is $30*10 = $300 (priced at the System Marginal Energy Cost, MEC, of $30/MWh). The total net Marginal Loss revenue is $600, and the Marginal Loss surplus is $600 - $300 = $300.

Case 2: Marginal Losses and Marginal Loss Payments with B as the Reference

With node B as the reference, the system-wide component of the LMPs is $33/MWh, and since there is no congestion, the congestion components of the LMPs are $0. The LMP components are as shown below:

Node	LMP (sys)	LMP (cong)	LMP (loss)	LMP (total)
A	$33	$0	-$3	$30
B	$33	$0	$0	$33

The total payments and presumed payments for Marginal Losses by different SCs are:

SC	MW Withdrawal at A	MW Withdrawal at B	Total Charge to the SC	Presumed Marginal Loss Charge to the SC
SC1	-110	0	- $3,300	$330
SC2	0	100	$3,300	$0
SC3	-100	100	$300	$300
SC4	0	0	$0	$0
Total	-210	200	$300	$630

The cost of average losses is now $33*10 = $330 (priced at the System Marginal Energy Cost, MEC, of $33/MWh). The total net Marginal Loss revenue is $630, and the Marginal Loss surplus is $630 - $330 = $300.

This example demonstrates that although the total system-wide Marginal Loss surplus ($300) is independent of the choice of the Reference Bus, assignment of Marginal Loss charges to individual SCs depends on the choice of the reference and is thus arbitrary. In the above example, SC1 was presumed to have been charged $0 for Marginal Losses when A was used as reference, but $330 when B was used as reference. Similarly, SC2 was presumed to have been charged $300 for Marginal Losses when A was used as reference, but $0 with B as reference.

Q. The above example shows that SC3 has a balanced schedule that has the same Marginal Loss charge regardless of whether node A or B is used as a reference. Why couldn't the CAISO reimburse the Marginal Loss of those SCs that submit balanced schedules?

A. Your observation that SC3's Marginal Loss payments are not dependent on the choice of the Reference Bus is correct in this case. However, please note two points: (1) this is correct in the absence of congestion, but not true in the presence of congestion; but more importantly: (2) it is not clear how much SC3 is contributing to the average losses. If you assume SC1 and SC3 had their schedules first, their contribution to average losses was $0.00025*(100)^2 = 2.5$ MW, leaving the responsibility for the remaining 10-2.5 = 7.5 MW of losses for SC3. However, if SC3 is assumed to have had its schedule first, its loss responsibility would have been 2.5 MW only. In each case the product of the loss quantity times the System Marginal Energy Cost would represent the average loss charge to SC3. For example, with A as reference, assuming SC3's schedule first, its presumed charge for average losses would be $30*2.5 = $75. Since its Marginal Loss payment was $300, its surplus payment would be computed as $300 - $75 = $225. However, assuming SC3's schedule last, its presumed charge for average losses would be $30*7.5 = $225. Since its Marginal Loss payment was $300, its surplus payment would be computed as $300 - $225 = $75. So there is no unique way of determining the surplus it deserves based on its individual contribution to loss payments. Even if a distributed bus were used as the reference and the Marginal

Losses of individual SCs were reimbursed, an equity issue would arise because the impact would be borne by other SCs who would be paying Marginal Losses.

Q. Couldn't a pro rata allocation of average losses resolve the problem you just mentioned?

A. In this simple case one may indeed agree on a pro rata allocation, allocating 50% of losses (5 MW) to SC3. However such a scheme would not work if there are two different SCs with balanced schedules in opposite directions on the line. There would be an argument that one is reliving the flow and reducing the losses and the other is exacerbating the losses. The ambiguity in allocating Marginal Losses based on average losses is also the reason why the CAISO chose to compute and allocate the Marginal Loss surplus system-wide, and did not choose to allocate Marginal Loss surpluses on a more granular ("PTO") basis.

C. Energy settlement based on Locational Marginal Prices

1. IFM Energy Settlement

Q. Is the IFM (and the Energy and Ancillary Service settlements that result from the IFM) a financially binding market that is separate from the HASP and the Real-Time Market?

A. Yes. Under MRTU, the CAISO will have a two-settlement system, namely Day-ahead and HASP/Real-Time. The accepted Day-Ahead IFM schedules will be settled based on IFM prices. Changes from Day-Ahead IFM schedules will be settled based on HASP prices for hourly (non-dynamic) System Resources (Imports and Exports), and based on Real-Time prices for internal Generation and Load.

Q. Is the total system-wide IFM Energy cost charged to Demand the same as the total system-wide IFM Energy payment to Supply?

A. No. Demand pays not only for the Energy payments made to suppliers, but also for the Congestion and Marginal Loss costs of transporting the Energy from Supply to Demand locations.

Q. Earlier, you mentioned uplift payments to generators for Minimum Load Energy and Bids that may not be able to set the price. Are these uplifts computed and settled in the Day-Ahead IFM?

A. Not entirely. The uplift payments to a Generating Unit take into account both the costs incurred and the revenues realized by that unit across all of the CAISO's markets, namely the Day-Ahead IFM, RUC, and HASP/Real-Time. The uplift payments are then repartitioned across the IFM, RUC, and HASP/Real-Time Markets and allocated to Demand in IFM, HASP, and Real-Time pursuant to a methodology based on the underlying cost causation. I will provide a more detailed discussion of this allocation process in the subsequent section on Bid Cost Recovery.

2. Energy Settlement in HASP

Q. Is the Energy settlement in HASP for import and export Energy a financially clearing market that is different from the IFM and Real-Time Markets?

A. Yes.

Q. Is it correct that only import and export Bids are considered in HASP in determining HASP Energy prices for settlement?

A. No. The HASP Energy prices (LMPs) are determined by taking into account both hourly import/export Bids and the Bids from internal resources-- both the hourly Bids from imports and exports and the Dispatch interval (5-minute) Bids from internal resources may set the HASP LMPs. However, the HASP LMPs are used for settling imports and exports only.

Q. How are the HASP LMPs computed?

A. The HASP LMP at every Scheduling Point is computed as the simple average of the four 15-minute prices (LMPs) at each Scheduling Point computed simultaneously at the pre-Dispatch time. The HASP LMPs are computed in this manner because the CAISO uses 15-minute rather than hourly Load forecasts for better accuracy in HASP.

Q. You mentioned earlier that the LMP at a location is no less than the highest accepted Supply Bid at that location and no higher than the lowest Demand Bid at that location. Is this true for the 15-minute HASP prices in each 15-minute interval?

A. The Bids accepted in HASP are accepted for the whole hour. The 15-minute prices computed for the relevant location (Scheduling Point) in HASP may individually be higher or lower than the accepted hourly Bid price at that location, but their simple hourly average will not be lower than the highest accepted hourly Import Bid price and will not be higher than the lowest accepted hourly Export Bid price at that location.

Q. Since the import and export quantities in HASP are generally not equal, there must be a surplus or deficit between payment to imports and charges to exports. How is this shortfall or surplus accounted for?

A. You are correct that there is a net collection or deficit as a result of Energy settlement in HASP, not only because of differences in market-clearing quantities of HASP import and export Energy, but also because of Congestion and losses. The net surplus or deficit resulting from the HASP Energy settlement is combined with any Real-Time Energy surplus (or deficit). The Congestion-related component of the combined HASP/Real-Time settlement surplus is used to first pay for any Congestion cost reversals associated with changes in balanced ETC/TOR schedules (compared to IFM), and any remaining amount is allocated to non-ETC/TOR Measured Demand (Loads and exports). The remaining HASP/Real-Time surplus or deficit is the Imbalance Energy Offset, which is allocated to Control Area Measured Demand, (including ETC/TOR Metered Demand).

3. Energy Settlement in Real-Time

Q. How are Real-Time LMPs determined?

A. The LMPs in Real-Time are determined by the Real-Time Economic Dispatch (RTED) process every 5 minutes for the Dispatch interval beginning 5 minutes later, using the Security Constrained Economic Dispatch (SCED) methodology. The RTED is targeted to meet the Imbalance Energy forecast for the Dispatch interval in question at least cost using Real-Time incremental and decremental Supplemental Energy Bids, while taking into account Congestion constraints, transmission losses, the actual operating points of Generating Units (based on telemetry), and the technical characteristics of Generating Units such as ramp rates, forbidden operating zones, and other unit constraints.

Q. How are Real-Time LMPs used to pay suppliers in Real-Time?

A. The Real-Time settlement interval is 10 minutes. Thus, there are two 5-minute LMPs at each location in each settlement interval. Resource-specific LMPs are computed for Dispatchable resources, including internal Generation, dynamically scheduled System Resources (Imports and Exports), and Dispatchable Loads.

Resource-specific LMPs are computed as the weighted average of the two 5-minute LMPs at the resource location, where the weights are the MWh quantity of Energy Dispatched in each of the two 5-minute Dispatch intervals. If there is no Energy Dispatched from a resource in either of the two 5-minute Dispatch intervals, the resource-specific LMP is the simple average of the two 5-minute LMPs at the resource location.

Q. How will Real-Time settlement work under MRTU?

A. Real-Time settlement will occur in two parts. First, each resource is paid for its Instructed Imbalance Energy ("IIE") based on the CAISO's Dispatch Instructions; in other words, in the first part of the Real-Time settlement process, the amount of Energy Dispatched by the CAISO is deemed delivered. Then, each resource is charged or paid for its Uninstructed Imbalance Energy ("UIE"), *i.e.*, the difference between its delivered quantity (metered quantity) and its amount of IIE. Additionally, as I discuss in greater detail below, uninstructed Energy outside a tolerance threshold may be subject to an Uninstructed Deviation Penalty ("UDP"), if and when UDP is implemented.

Q. Are the resource-specific LMPs just described used to calculate payments and charges associated with both instructed and Uninstructed Deviations (before applying any Uninstructed Deviation Penalty)?

A. No. The resource specific 10-minute LMPs will be used for instructed Energy settlement. Uninstructed Energy is settled in two tiers before applying any applicable Uninstructed Deviation Penalty. The first tier consists of undelivered Energy that was paid for as instructed Energy, and is charged a different price, namely, the Uninstructed Imbalance Energy (UIE) price. The second tier consists of uninstructed Overgeneration and is charged the simple average of the two 5-minute prices at the resource location.

Q. How is the UIE (first tier) rate computed?

A. The Uninstructed Imbalance Energy (UIE) price is based on the $/MWh rate the resource was paid for its instructed Energy, including any Residual Imbalance Energy, i.e., instructed Energy from Dispatch instructions issued in Dispatch intervals outside the Settlement Interval. It is obtained by computing all payments to the resource for instructed Energy other than Residual Imbalance Energy (RIE) at the resource priced at the LMP of the resource and the payment for Residual Imbalance Energy priced at the relevant (RIE) Bid price divided by the sum of the respective quantities.

Q. Can you provide an Example of Tiered Allocation of Uninstructed Imbalance Energy?

A. Yes.

Example III.10:

Consider a Generator with an IFM schedule of 120 MW in two successive hours, and with no schedule change in HASP. Assume in the second Settlement Interval of the second hour it has Residual Imbalance Energy from a Dispatch interval in the previous hour, where its Bid price was $80/MWh. The RIE MW target above the IFM/HASP schedule is 24 MW for the first Dispatch interval an 12 MW for the second. In the current Settlement Interval it has incremental instructions of 24 MW in each of the two Dispatch intervals. Its Dispatch Operating Targets (DOT) are thus 120+24+24 = 168 MW in the first Dispatch interval, and 168+24 = 180 MW in the second Dispatch interval. The LMPs are $40/MWh and $50/MWh respectively in the two Dispatch intervals. The following table summarizes the MW schedules and corresponding MWh instructions. In each Dispatch interval the MWh quantity is computed by multiplying the DOT by (5 minute/60 minutes), i.e., 1/12. The inter-temporal ramps are ignored for computational simplicity in this example, but the simplification does not change the intent of the example.

	First Dispatch Interval		Second Dispatch Interval	
	MW	MWh	MW	MWh
Schedule	120	10	120	10
RIE	24	2	12	1
IIE (non-RIE)	24	2	48	4
DOT	168	14	180	15
LMP	$40		$50	

The resource is expected to generate 14+15 = 29 MWh in the Settlement Interval. Thus includes

- MWh based on the IFM/HASP schedule: 10+10=20 MWh
- MWh for the RIE: 2+1 = 3 MWh, and
- MWh for IIE: 2+4 = 6 MWh.

The resource is paid based on the instructed deviations as follows:

Payment for RIE: $80*3 = $240.

The resource-specific LMP for the Settlement Interval is computed based on the IIE (non-RIE) MWh instructions and the LMPs:

Resource Specific LMP (IIE Rate) = (($40*2) + ($50*4))/(2+4) = $46.67/MWh

Payment for IIE (non-RIE): $46.67*(2+4) = $280

The UIE Tier 1 Rate for the resource is computed based on all instructed incremental Energy, including the IIE and the RIE quantities and prices:

Resource Specific UIE (Tier 1) Rate = ($240+$280)/(3+6) = $57.78/MWh

The UIE Tier 2 Rate is computed as the simple average of the two Dispatch interval LMPs: ($40+$50)/2 = $45/MWh.

Case 1: Metered Generation for the Settlement Interval is 15 MWh

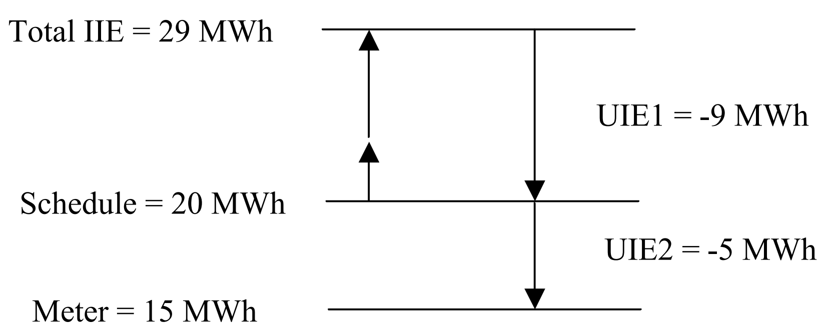
The quantity of metered Generation is 14 MWh short of the expected 29 MWh the resource was paid to produce: 29-15 = 15 MW. Based on its IFM/HASP schedule even (without a Real-Time instruction), it was obligated to deliver 10+10 = 20 MWh. So, the total Uninstructed Imbalance Energy is divided into two Tiers:

Total UIE = -14 MWh

UIE1 (undelivered IIE) = -9 MWh

UIE2 (remaining UIE) = -5 MWh

This is illustrated schematically in the following diagram:



The applicable UIE charges (before any UDP) are:

- UIE1: $57.78*9 = $520 (Tier 1)
- UIE2: $45*5 = $225 (Tier 2)

The net settlement with the resource (before UDP) is thus a charge of $520+$225 - $240 -$280 = $225 for the Settlement Interval.

Case 2: Metered Generation for the Settlement Interval is 30 MWh

The quantity of metered Generation is 1 MWh more than the expected 29 MWh the resource was paid to produce. There is no Tier I UIE. The Tier 2 UIE is 1 MWh. The payment amount is based on the simple average of the two LMPs. $45*1 = $45.

The net settlement with the resource (before UDP) is thus a payment of $240+$280+45 = $565.

Case 3: Metered Generation for the Settlement Interval is 23 MWh

The quantity of metered generation is 6 MWh less than the expected 29 MWh, but is above the IFM/HASP scheduled quantity of 20 MWh. So, it is entirely a Tier 1 UIE. The UIE charge is $57.78*6=$346.68.

The net settlement with the resource (before UDP) is thus a payment of $240+$280-346.68 = $173.32.

Q. How are Real-Time LMPs used to charge (or pay) Load in Real-Time?

A. Dispatchable Loads are paid based on resource-specific LMPs in the same manner as Supply resources, which I just explained. Non-Dispatchable Loads are settled in Real-Time based on their deviation from IFM Load schedules. Because some SCs may be consuming more and some less than their IFM scheduled Load, in order to avoid costs shifts among SCs without creating revenue neutrality problems, there is a need for two effective Real-Time LAP prices, one for settling positive Load deviations and one for settling negative Load deviations. This is accomplished by creating an hourly Load Aggregation Point (LAP) price and an hourly LAP Price Adjustment. Both of these prices are hourly and are computed based on the 5-minute LMPs at the Load nodes in the Load zone. The LAP price is applied to all positive and negative Load deviations, and the LAP Price Adjustment is applied as a positive price adder to positive Load deviations and as a negative price adder to negative Load deviations.

Q. Why are there two prices for Real-Time settlement with Loads?

A. The reason for computing two prices is that a single price could turn out to be extremely excessive if the Load deviations of individual SCs are large and in opposite directions, but the net Load deviation at the LAP is very small (*i.e.* close to 0 MW).

Q. Can you illustrate this concept by way of an example?

A. Yes.

Example III.11:

Consider a LAP with just two nodes, A and B. The Real-Time deviation at the LAP level is only 5 MW, but because of the change in LDFs between the forward and Real-Time markets, the Real-Time deviation at node A is +200 MW and at node B is –195 MW (resulting in a net deviation of 5 MW). The Real-Time LMPs are LMP_A = \$25/MWh and LMP_B = \$10/MWh. Thus the CAISO's revenue requirement to settle the Real-Time deviations is \$25*200 - \$10*195 = \$3,050.

A logical single price for settlement of LAP Load deviations would be the weighted average of the LMPs, weighted by the algebraic quantity of nodal Load deviations, i.e., (\$25*200 - \$10*195)/(200-195) = \$610/MWh. This is a very high rate that could have large impacts on settlement with individual SCs.

Assume there are two SCs, SC1 is over-consuming (Real-Time Load exceeding the forward Load schedule) by 100 MW and SC2 is under-consuming (Real-Time Load less than the forward Load schedule) by 95 MW. With the single rate of \$610/MWh just computed, SC1 would be charged \$610*100=\$61,000, and SC2 would be paid \$610*95 = \$57,950. The net collection by the CAISO resulting from such settlement is equal to CAISO's revenue requirement ($3,050) computed above: $61,000 - $57,950 = $3,050.

Q. How can excessive charges and payments to individual SCs be avoided?

A. To avoid the problem of excessive charges and payments to individual SCs, a Real-Time LAP price can be computed using absolute MWh deviations of Loads at individual nodes. However, such a LAP price, if applied without adjustment, would not be revenue-neutral in the sense that the collection from SCs consuming more than their IFM schedule and payment to SCs consuming less than their IFM schedule would not be the same as this price times the difference between the metered consumption and IFM schedule in the LAP.

Q. Can you illustrate this concept using an example?

A. Yes.

Example III.12:

Using the assumptions set forth in the previous example, the absolute values of nodal deviations are 200 MW at node A and 195 MW at node B. The LAP price based on these absolute value deviations is ($25*200 + $10*195)/(200+195) = $17.59/MWh. Charging the two SCs at this rate would result in a charge of $17.59*100 = $1,759 to SC1, and a payment of $17.59*95 = $1,672 to SC2. The net collection by the CAISO would then be $1,759 - $1,672 = $87, far below CAISO's revenue requirement of $3,050.

Q. How can both problems of high LAP prices and revenue inadequacy be resolved?

A. To avoid both the problem of unreasonable LAP prices and the risk of revenue non-neutrality, a LAP price adjustment is computed. This $/MWh price adjustment is applied as an adder for SCs that consume more than their IFM Load and is negative for SCs that consume less than their IFM Load.

Q. How is the LAP Price Adjustment determined?

A. The LAP Price Adjustment is computed as follows:

1) First, the total net amount that the CAISO would have charged (or paid) Load deviations at the LAP is determined by multiplying the hourly nodal LMPs (the simple average of twelve 5-minute LMPs) by the relevant Load deviation at each node (whether positive or negative).

2) Next, the total net amount that the CAISO would charge (or pay) the SCs based on their individual LAP level deviations is calculated using the LAP price.

3) Next, the sum of the absolute values of the LAP level deviations of all SCs is determined (whether the SC has a positive or negative Load deviation, the absolute value is considered here).

4) Finally, the LAP Price Adjustment is computed by subtracting the total net amount that the CAISO would have charged Load deviations at the LAP (from step 1) from the total net amount that the CAISO would charge or pay SCs based on their individual LAP level deviations (from step 2), and dividing this amount by the sum of the absolute values of the LAP level deviations of all SCs (from step 3).

Q. Can you illustrate the computation and use of the LAP price adjustment?

A. Yes.

Example III.13:

The assumptions used in the previous example result in a reasonable LAP price ($17.59), but this price results in revenue inadequacy. The amount of revenue inadequacy is $3,050 - $87 = $2,963. Dividing the revenue shortfall by the sum of the absolute values of individual SC LAP deviations yields the sought LAP price adjustment: $2,963/(100+95) = $15.19.

The SCs with positive Load deviations are charged the sum of the LAP price computed in Example III.9 and the adjustment computed here, i.e., $17.59+$15.19 = $32.78. The SCs with negative Load deviations are paid the difference between the LAP price computed in Example III.9 and the adjustment computed here, i.e., $17.59-$15.19 = $2.41.

With these rates, SC1 pays $32.78*100 = $3,278, and SC2 is paid $2.41*95 = $228. The net revenue is $3,278 - $228 = $3,050. The CAISO is revenue adequate.

Q. Is this the approach the CAISO has adopted?

A. Yes. However, please note that in Examples III.8, III.9, and III.10 a single LMP was assumed for each node. Load deviations are settled on an hourly basis, so there is a need to compute hourly nodal LMPs. The approach that the CAISO has adopted is to use the simple average of the 5-minute LMPs at each node to compute an hourly nodal LMP for that node.

Q. Based on the explanation above, how is the Real-Time LAP price computed?

A. The Real-Time LAP price is computed in the following manner. First an hourly LMP at each Load node in the LAP is computed as the simple average of the 5-minute LMPs at that node. Then, these hourly nodal LMPs are weighted by the absolute value of Load deviations (the difference between Real-Time hourly MWh Load and IFM Load) at the respective nodes to compute the LAP price.

Note that the IFM Load at a node is based on distribution of the IFM LAP Load schedule using the Load Distribution Factors (LDFs) available to IFM, whereas Real-Time nodal consumption is based on LDFs determined from metering. Since meter data is not available in Real-Time, the LDFs used for Real-Time data publication are based on the average of the State Estimator LDFs over the hour. However, for settlement purposes LDFs based on metered data are used. Therefore, the Real-Time LAP prices published immediately after the Real-Time market and those used for final settlement may not be exactly the same.

IV. UNINSTRUCTED DEVIATION PENALTIES

Q. Please explain Uninstructed Deviation Penalties (UDP) as they exist under the currently effective CAISO market design (Phase 1b).

A. UDP is a measure that was included as part of Phase 1b in order to ensure compliance with CAISO's Real-Time Dispatch instructions. Under Phase 1b, UDP applies to Uninstructed Deviations by Generators and Dynamic System Resources outside a Tolerance Band defined as the greater of 5 MW or 3% of a unit's maximum resource capacity (Pmax). Uninstructed incremental deviations outside of this Tolerance Band are not paid (or stated differently are charged a penalty of 100% of the applicable Energy price in that Settlement Interval) for the Imbalance Energy if the interval price is non-negative, and uninstructed decremental deviations beyond the Tolerance Band are subject to a premium of

50% of the applicable Energy price in that Settlement Interval if the interval price is non-negative.

Q. Is the CAISO currently charging UDP?

A. No. Implementation of UDP in Phase 1b was delayed due to several factors, including concerns raised by some stakeholders that Dispatch instructions under Phase 1b sometimes cause Generating Units to change direction too frequently, reporting outages through the ISO's current system is cumbersome, and there may be situations where Uninstructed Deviations that trigger UDP are unavoidable. Although the CAISO has not, to date, been assessing UDP, the CAISO has been providing advisory settlement data to SCs to show what their UDP charges would have been if UDP had been implemented. The CAISO has also been monitoring certain reliability metrics, with the intention of filing a tariff amendment to propose an immediate effective date for application of UDP if those metrics exceed a certain threshold.

Q. Does UDP apply to all Generators under the CAISO's current Phase 1b market design?

A. No. Under the current Phase 1b market design, UDP does not apply to the following Generators:

- Generators without Participating Generator Agreements (PGA).
- RMR Condition 2 units

- Load-following Metered Sub-System units
- Participating Intermittent Resource Program (PIRP) units that meet the scheduling requirements of the PIRP program
- Regulatory Must-Take units
- Units scheduled to provide Regulation that are actually on Automatic Generation Control (AGC) and provide Regulation according to CAISO set point signals
- QF units that have signed a QF-PGA and have sold all of their output under a Power Purchase Agreement (PPA).

Q. Does the CAISO plan to adopt UDP as part of MRTU?

A. Yes it does, but just like today, and as I explain further below, the UDP provisions will be in the MRTU tariff but will not be enforceable until the CAISO separately files for permission from the Commission to implement the UDP.

Q. Would the current UDP be modified under MRTU?

A. Only to the extent that the current UDP needs to be modified in order to make its effectiveness in discouraging strategic Uninstructed Deviations comparable under MRTU as it is today.

Q. Please describe UDP under MRTU.

A. The proposed UDP mechanism for MRTU will still be based on assessing penalties to Uninstructed Imbalance Energy (UIE) in excess of a Tolerance Band in each 10-minute Settlement Interval. An infraction will be registered in a Settlement Interval when UIE from a resource exceeds the applicable UDP Tolerance Band, (which is the same as the current threshold of the greater of 3% of the maximum resource capacity (Pmax) or 5 MW), over 10 minutes. However, under MRTU the deviation quantity will be determined by multiplying the actual MWh deviation subject to UDP (*i.e*. the number of MWh outside of the Tolerance Band) by a multiplier that will increase based on the number of infractions in an hour. The number of infractions is reset to zero at the top of each hour for the next hour. Also, under MRTU, UDP would continue to apply only for nonnegative Real-Time prices (as under Phase 1b), and would be based on the Real-Time Energy price (resource-specific LMP) times an Energy Price Penalty Factor (equal to 100% for positive deviations and 50% for negative deviations) times the relevant scaled Uninstructed Deviation quantity in MWh outside the Tolerance Band (*i.e*., MWh deviation times the multiplier). The Real-Time price used would be the resource-specific LMP defined as (a) the weighted average of the 5-minute LMPs at the resource's location if the resource has non-zero MWh instructed Energy Dispatch, or (b) the simple average of the 5-minute LMPs at the resource's location if the resource has no instructed Energy for either of the two 5-minute Dispatch intervals.

Q. What is the justification for using the multiplier in MRTU?

A. The reason for the use of the multiplier in MRTU is to ensure that the UDP under MRTU is as effective in discouraging Scheduling Coordinators from deviating from Dispatch Instructions as it is under Phase 1B. Under MRTU, a resource is Dispatched based on its ramp rate, physical limits and its current telemetered output. This last factor is particularly important, because, as a result, Dispatch Instructions under MRTU will be generally feasible because prior Uninstructed Deviations will be taken into account in issuing new Dispatch Instructions. This is in contrast to the Dispatch methodology employed in Phase 1b, which calculates the Dispatch range for each resource based on the last Dispatch Operating Target ("DOT") (defined as the resource's operating target issued in the previous Dispatch for the current interval), which assumes that the resource followed the preceding Dispatch Instruction, as well as the applicable ramp rate and capacity limits. Because MRTU will issue Dispatch Instructions taking into account telemetered output, a resource that does not follow Dispatch Instructions under MRTU will be exposed to UDP only for the amount of Energy that can be ramped within a Dispatch Interval. Thus, its Uninstructed Deviation quantity does not accumulate as it does in Phase 1b. Because of this, UDP under MRTU is so diluted that short of additional measures, it would cease to be a credible deterrent against Uninstructed Deviations. Therefore, the CAISO intends to introduce under MRTU the deviation multiplier that I explained in the preceding answer in order to rectify this problem and bring the level of UDP for strategic deviations on par with Phase 1b.

Q. Can you provide an example demonstrating how UDP would be calculated in MRTU, and the difference between that calculation and the calculation of UDP under Phase 1b?

A. Yes. Consider a 200 MW resource with a 20 MW HASP Schedule (*i.e.*, a Schedule submitted in HASP, or Day-Ahead Market Schedule if no adjustments were made to it by the SC in HASP), a 3 MW/min ramp rate, and a Bid of $20/MWh. Assume that the LMP at the resource location is $40/MWh throughout the hour. Consequently, under MRTU, the resource would be Dispatched economically above its HASP Schedule. Its DOT for the first 5-minute Dispatch Interval would be 20 + (3 * 5) = 35 MW. However, the resource does not respond to Dispatch Instructions, instead staying at its schedule of 20 MW. In Phase 1b, the resource would be Dispatched incrementally by 15 MW in each 5-minute Dispatch Interval, from the preceding DOT, starting with a DOT of 35 MW for the first interval, increasing the DOT by 15 MW in each subsequent 5-minute interval, and finishing with a DOT of 200 MW for the last (12th) interval of the hour. In MRTU, the resource would also be Dispatched incrementally by 15 MW in each 5-minute Dispatch Interval, but all Dispatches within the hour have a DOT of 35 MW because the resource telemetry would remain at 20 MW. In all cases, the UDP tolerance is 1 MWh (200 x 0.03/6). For the non-responsive resource in the example above, under the proposed multiplier methodology, six infractions would be registered within the hour, resulting in a penalty multiplier of 11. Therefore, the scaled UDP would be $55 (*i.e.*, 11 x 0.5 x $40 x (1.25–1.0)) in each Settlement Interval, for a total penalty of $330. In contrast, under the Phase 1b methodology, which does not take into account telemetry data in Dispatch Instructions, the total penalty for these six Settlement Intervals would be $1,680. Thus, even with the use of the multiplier, penalties could still be substantially reduced under MRTU. However, if the CAISO were, in this example, to combine the Phase 1b UDP methodology (*i.e.* by discarding the multiplier) with the MRTU Dispatch system, the result would be a mere $5 penalty for each Settlement Interval, for a total penalty of $30 the hour.

Q. What are the multipliers that will be used under MRTU, and what is the basis for these multipliers?

A. The following Table lists the multipliers that will be used to calculate UDP under MRTU based on the number of infractions in the hour.

Number of Settlement Intervals During the Hour with Uninstructed Deviations Outside the Resource's Tolerance Band	Deviation MWh Multiplier
0	0
1	1
2	3
3	5
4	7
5	9
6	11

The basis for these multipliers is the result of the representative example just provided above, *i.e.*, without using these multipliers, a unit that does not follow Dispatch Instructions under MRTU would be charged an insignificant penalty that would not appropriately discourage Uninstructed Deviations. The following table shows how the volume of the uninstructed Energy deviation increases in Phase 1b compared to MRTU, and the resulting penalties under each of the three scenarios (Phase 1b, MRTU without multiplier, and MRTU with multiplier).

		Phase 1b			**MRTU**				
Settlement Interval	Dispatch Interval	Dispatch (MW)	UIE (MWh)	UDP	Dispatch (MW)	UIE (MWh)	Unscaled UDP	Infractions	Scaled UDP
1	1	35	–2.5	$30	35	–1.25	$5	1	$55
	2	50			35				
2	3	65	–7.5	$130	35	–1.25	$5	1	$55
	4	80			35				
3	5	95	–12.5	$230	35	–1.25	$5	1	$55
	6	110			35				
4	7	125	–17.5	$330	35	–1.25	$5	1	$55
	8	140			35				
5	9	155	–22.5	$430	35	–1.25	$5	1	$55
	10	170			35				
6	11	185	–27.5	$530	35	–1.25	$5	1	$55
	12	200			35				
Total			**–90**	**$1,680**		**–7.50**	**$30**	**6**	**$330**

Comparing the columns labeled UIE (MWh) the ratio of the difference between the quantity of Uninstructed Deviation under Phase 1b and MRTU to the Uninstructed Deviation under MRTU is (2.5 – 1.25) / (1.25) = 1 in the first 10-minute interval, ((2.5 + 7.5) – (1.25 - 1.25)) / (1.25 + 1.25) = 3 in the second interval, ((2.5 + 7.5 + 12.5) – (1.25 + 1.25 + 1.25)) / (1.25 + 1.25 + 1.25) = 5 in the third interval, etc.

Q. Under MRTU, how does the UDP work when the resource has no economic Bid in Real-Time and simply deviates from its schedule?

A. As I said earlier, under MRTU the Dispatch is from telemetry. If the resource has no Real-Time Energy Bid, and the telemetry indicates it has a deviation from its Schedule, the Real-Time Dispatch would simply instruct the unit to go to its Schedule, considering the unit's physical parameters, primarily its ramp rate. To the extent the unit does not follow the instruction (within the Tolerance Band), it incurs UDP.

Q. Are there any circumstances under which the UDP assessed under MRTU would be greater than the UDP assessed under the CAISO's current market design?

A. Yes. In the case of units with a very high ramp rate, it is possible that, under certain circumstances, the continued strategic failure of such units to generate pursuant to their Bids or schedules could result in those units being assessed a higher UDP under MRTU than would have been the case under the CAISO's current market design.

Q. Can you provide an example to illustrate such an outcome?

A. Yes. Consider a 1,000 MW unit with ramp rate of 30 MW/min, a HASP Schedule of 700 MW, and Energy Bid of $20/MWh. Assume that the LMP at the resource location is $40/MWh throughout the hour. Consequently, under MRTU, the resource would be Dispatched economically above its HASP schedule. As in the previous example, assume the unit does not follow the Dispatch Instructions, and stays at its HASP schedule of 700 MW. So, the MRTU UDP multiplier will be 11 (corresponding to 6 infractions for the hour). Following the same computations as in the first example, the UDP under Phase 1b would be $4,900, whereas the UDP under MRTU would be $9,900.

Q. Do you believe that such a possibility is indicative of a need to modify the proposal for implementing UDP under MRTU, as you explained it above?

A. No. It is important to understand that in cases where a unit simply ignores CAISO Dispatch Instructions, it is withholding Energy that it committed to make available pursuant to a Bid or Schedule. For instance, if a unit was unable to comply with a Dispatch due to an outage, the unit owner would merely need to inform the CAISO of that fact to be exempted from UDP. Energy from units with very fast ramp rates is particularly valuable, because of the flexibility that it affords operators in making Dispatch decisions. Therefore, the CAISO believes that it is appropriate that such behavior be subject to significant penalties, even if the penalties might be higher, under some circumstances, than those that would have been imposed under the current market design.

Q. Does the CAISO plan to implement UDP immediately upon commencement of MRTU?

A. No. As I indicated above, just as with Phase 1b, the CAISO plans to monitor Uninstructed Deviations and not assess UDP in the initial implementation of MRTU. The CAISO will monitor (for each Settlement Interval) the following three parameters for each resource:

1) MWh quantities of Uninstructed Deviations (MWDEV) outside the Tolerance Band.
2) The relevant multiplier, computed based on the number of infractions per operating hour committed by a resource, and the scaled MWh quantities computed as the product of MWDEV and the multiplier.
3) UDP charges, which would apply if UDP were implemented, taking into account the current exemptions applicable to qualified resources.

Similar to the current (Phase 1b) practice, the CAISO would continue to monitor the reliability metrics and would implement UDP if the metrics exceed the established thresholds.

Q. You stated earlier that UDP does not apply to certain types of Generators under Phase 1b. Will there also be certain types of Generators exempted from UDP under MRTU?

A. Yes. As with Phase 1b, units without PGAs are exempt from UDP, as are PIRP units with PGAs. Also, QFs with a power purchase agreement under which, pursuant to PURPA, they are obligated to sell all of their output net of their own use, will not be subject to UDP for deviations from their schedules. The exemptions will continue for RMR Condition 2 and Regulatory Must Take units. There is a change regarding the exemption of the MSS units compared to Phase 1b, in that under MRTU, only the MSS units designated as "Load following" units are exempt from UDP, whereas in Phase 1b all units under a Load following MSS were exempt.

V. CONGESTION CHARGES AND CRR PAYMENTS

Q. Under MRTU, what could constitute the source of a CRR?

A. The source of a CRR, under MRTU, could be a physical Generation node, an Intertie Scheduling Point, a Trading Hub, a Default LAP, a sub-LAP, or a MSS LAP. All such sources may be nominated in the CRR auction; however, for CRR Allocations, the Load-Serving Entities ("LSEs") serving Load within the CAISO Control Area may nominate only physical Generation nodes, Intertie Scheduling Points, and Trading Hubs, and out-of-Control Area Load may nominate only physical Generation nodes.

Q. Under MRTU, what could constitute the sink of a CRR?

A. The sink of a CRR, under MRTU, could be a Default LAP, a sub-LAP, an MSS LAP, an Intertie Scheduling Point, a physical Generation node, or a Trading Hub. All such sinks may be nominated in the CRR auction; however, for CRR Allocations, the LSEs serving Load within the CAISO Control Area may nominate only Default LAPs (but also sub-LAPs in the last Tier of the allocation process as explained in Dr. Scott Harvey's testimony, Exh. No. ISO-3), and MSS LAPs as relevant, and out-of-Control Area Load may nominate only Intertie Scheduling Points.

Q. How often will CRRs be auctioned?

A. CRRs will be auctioned annually and monthly following the annual and monthly CRR allocations. Annual CRR allocation/auctions will be conducted approximately 2-3 months prior to the trade year for which CRRs are valid. In the annual process, CRRs will be allocated and auctioned separately for the peak- and off-peak periods of each season. The CAISO will allocate 75% of the capacity of transmission paths for each season in order to accommodate both CRR auctions and allocations (including the CRR Obligations modeled by CAISO to ensure allocated and auctioned CRR revenues are not adversely impacted by the reversal of ETC and TOR and converted ETC Congestion charges). The base network model (with all transmission facilities in service) will be used for annual CRR allocation/auctions. Monthly CRR allocations/auctions will be conducted about 30-45 days prior to the trade month and the remaining 25% of transmission capacity will be released for monthly CRR release. The known transmission outages and derates will be incorporated in the network for the monthly CRR release.

Q. What charges are applied to the entities nominating CRR allocations?

A. Internal Control Area LSEs and entities entitled to receive Merchant Transmission CRRs are not charged for the CRR Allocations they receive. Out-of-Control Area Load-Serving Entities must pre-pay the Wheeling Access Charges ("WAC"), at the WAC rate applicable to the export scheduling point that they designate as the CRR sink, for the CRR term (season or month and TOU period for the CRR they want to nominate) and quantity of CRRs they wish to nominate. In other words, for each MW of CRRs nominated, the nominating LSE must prepay one MW of the WAC for the number of hours of the CRR cycle (note that WAC is charged in $/MWh). For example, if the external Load-Serving Entity wishes to nominate CRRs for all seasonal peak and off peak periods, it will pre-pay the WAC for 8,760 MWh for each CRR MW it wishes to nominate. For an incremental MW peak period CRR nomination in the monthly allocation, for a month with 448 peak hours, the LSE would prepay the WAC for 448 MWh for each MW CRR it nominates.

Q. What does CAISO do with the WAC pre-payments made by the out-of-Control Area Load-Serving Entities to nominate CRRs?

A. Within 30 days following the allocation of the relevant CRRs, the CAISO will reimburse the Load-Serving Entity representing the out-of-Control Area Loads (OCAL) the difference between the amount of the WAC pre-paid and the WAC for the MW amounts of CRRs that the entity was actually allocated. The CAISO will exempt such entities, through their SCs, from paying WAC for any Export schedules at the Scheduling Point corresponding to the sink of each allocated CRR, on an hourly basis for the period for which the CRR is defined, until the pre-paid funds are exhausted. At the end of the period for which the CRR is defined any remaining balance will be allocated to the relevant PTOs. To the extent the pre-paid balance amount is exhausted prior to the end of the duration of the awarded CRR, the Scheduling Coordinator for the entity will be charged for the WAC.

For example, assume the WAC at a given export Scheduling Point is $2.75/MWh. An external Load-Serving Entity wishes to nominate 120 MW CRRs with sink at this Scheduling Point for the peak hours of a CRR season. Assume there are 1,200 peak hours in the CRR season. The WAC pre-payment per MW of CRR nomination is $2.75*1200 = $3,300. Thus the entity prepays $3,300*120 = $396,000. Assume the entity is allocated only 100 MW of its 120 MW nominated CRRs in the annual CRR allocation for the peak hours of the season in question.

The WAC pre-payment for this amount is $3,300*100 = $330,000. The CAISO will reimburse the entity for the difference of $396,000 - $330,000 = $66,000 within 30 days following the annual CRR allocation/auction.

Now assume for simplicity that the entity's Scheduling Coordinator schedules the same amount of exports in every peak hour of the season on behalf of the entity that owns the CRRs, and these schedules clear the Day-Ahead Market and are not changed in Real-Time. Consider two cases:

Case 1: The hourly schedules are 120 MW. In this case the pre-paid WAC covers the first 1,000 peak hours of the season since $330,000/($2.75*120) = 1,000. For the remaining 200 peak hours of the season, the entity will get charged $2.75*200*120 = $66,000 of WAC.

Case 2: The hourly schedules are 90 MW. In this case the pre-paid WAC exceeds the WAC charges corresponding to the export schedules for the peak hours of the season, *i.e.*, $2.75*90*1200 = $297,000. The difference (*i.e.*, $330,000 - $297,000 = $33,000) is paid to the PTO(s) that are entitled to receive WAC payments for the export Scheduling Point in question.

Q. What charges/payments are applied to the participants in the monthly and seasonal CRR auctions?

A. Market Participants taking part in the CRR auction will have to post collateral for the maximum amount they wish to spend to purchase CRRs. The CRR auction winners will be charged (or paid) the Market Clearing Price for CRRs obtained through the clearing of the CRR auction (Market Participants purchasing negative value CRR Obligations will be paid the Market Clearing Price). The CAISO will net all auction revenues received and payments made through this process.

Collateral posted to participate in the auction is released after payment of auction charges.

Q. How are seasonal and monthly auction revenues allocated?

A. The CRR net auction revenues will be paid to the PTOs in proportion to their Transmission Revenue Requirements (TRR) over the CRR term.

Q. Is it possible for the CRR auction to result in net revenue shortfall?

A. No. The seasonal CRR simultaneous feasibility (conducted in both the allocation and the auction processes) results in Market Clearing Prices with non-negative auction revenues in the CRR auction.

It is possible for transmission outages and derates to render seasonal CRRs infeasible when superimposed on the transmission network used for the monthly CRR allocation and auction. In such cases, the CAISO will re-rate the congested transmission lines just enough to make the annual CRRs feasible. This approach guarantees that the CRR net auction revenues will not be negative.

Q. What payments are the holders of CRR Obligations and CRR Options entitled to?

A. For each trading hour in the Day-Ahead IFM, Obligation CRRs are entitled to a payment or charge based on the difference between the Marginal Congestion Cost component (MCC) of the CRR sink and the CRR source LMPs multiplied by the amount (MW) of CRRs held. Unlike CRR Obligations, CRR Options are not charged if the MCC at their sink is lower than their source MCC. There are no additional CRR payments or charges based on HASP or Real-Time Congestion.

If the total net IFM Congestion revenues for the trade hour (after the reversal of ETC and TOR IFM Congestion charges or revenues) are sufficient to make the required net CRR Payments, all CRR Holders will be paid and charged fully up to their entitlements in that trade hour. Any surplus for the trade hour after making all hourly net CRR payments will go to the CRR Balancing Account for use in the end-of-month clearing and end-of-year true-up and clearing of the CRR Balancing Account. The total net IFM Congestion revenues for each trade hour include the sum of (1) the net Day-Ahead revenues from Energy injection and withdrawal from the CAISO Controlled Grid based on the Marginal Congestion Cost component of the LMPs, excluding Congestion charges/credits for ETC and TOR schedules, and (2) Congestion revenues from AS imports on congested Interties.

If the total net IFM Congestion revenues for the trade hour are insufficient to make the required net CRR Payments, then the CRR Payments and CRR charges will be pro-rated by a ratio equal to the total hourly amount of the net IFM Congestion revenues divided by the net of CRR Payments and CRR charges. Any revenue shortfalls and charge shortfalls for the trade hour will be tracked for further Settlement (true up) during the end-of-month clearing process.

Q. What could cause revenue inadequacy for CRR Holders?

A. If the CRRs are simultaneously feasible when applied to the network used in the IFM, the IFM Congestion revenues will be sufficient to pay all CRR entitlements fully, regardless of whether the IFM schedules match the CRRs or are vastly different. This will be the case if the transmission capacities used in the IFM are no less than the transmission capacity that was used for CRR allocation/auction, and if the same LDFs are used to compute both the Day-Ahead Congestion charges and the CRR Payments.

If the transmission capacity has become unavailable due to outages or derates, however, the Congestion revenue may not be sufficient to pay the CRR Holders fully. This can happen in any hour when the CRRs that have already been allocated and auctioned are not simultaneously feasible because of transmission outages or derates during that hour. By the same token, transmission derates that may render seasonal CRRs infeasible with respect to the network used for the monthly CRR allocation and auction could increase the probability of revenue shortfall to pay the CRRs during the month.

Q. In the case of net revenue shortfall, why are both CRR payables and receivables prorated?

A. One alternative would have been to charge the CRR counter-flows fully at all times. However, stakeholders expressed concern with that approach and supported prorating both CRR payables and receivables in case of net revenue deficiency. The CAISO and the stakeholders adopted this approach primarily because it is in line with some logical expected properties of CRRs. For example, an entity having equal amounts of CRR Obligations from A to B and B to A should logically have a net zero charge/payment regardless of the hourly net IFM Congestion revenues. This would not be the outcome if in the case of hourly net Congestion revenue shortfall, the payment due to one of the CRRs (*e.g.*, A to B) were prorated, but the other (B to A) were charged to the full. Another important logical property would be equivalence of having CRR Obligations from A to B and B to C with CRR Obligations from A to C. Again these two CRR configurations may not have the same settlement unless counterflow CRRs are prorated in the case of hourly net IFM Congestion revenue shortfall as demonstrated below.

Consider a CRR Holder with 100 MW of CRR Obligations A to B and 100 MW of CRR Obligations from B to C. Assume the marginal Congestion components (MCC) of the IFM LMPs are MCC A = $10, MCC B = $30, and MCC C = $20. The CRR Holder should be entitled to Congestion charges/payments as if it had 100 MW of CRR Obligations from A to C. Under the approach adopted by CAISO and the stakeholders, in the case of hourly revenue shortfall, both the CRR Payment from A to B ($2,000) and CRR charges from B to C ($1,000) will be reduced pro rata. For example, if the shortfall is 10%, the CRR Holder will be paid $1,800 for its CRRs from A to B, and charged $900 for its CRRs from B to C, for a net payment of $900. Note that this would be the same payment that the CRR Holder would have received for 100 MW of CRR Obligations from A to C under such shortfall conditions. In contrast, if the CRR Holder were charged to the full for its counterflow CRRs from B to C, it would have been paid $1,800 – $1,000 = $800; this would have been $100 less than the payment for CRRs from A to C.

Q. How does the monthly clearing of the CRR Balancing Account work?

A. The available funds in the CRR Balancing Account for a trade month are derived from hourly net surplus revenues from Day-Ahead IFM Congestion revenues applicable to the month. At the end of each month, if that month's CRR Balancing Account contains excess revenue, it will be used to pay down the net CRR shortfall for that month.

If the net CRR shortfall for the month is less than the revenue in the monthly CRR Balancing Account, all CRR monthly payment and charge shortfalls will be fully paid and charged (in the case of counterflow CRRs) and the net payment will be debited to the monthly CRR Balancing Account. The remaining revenue in the monthly CRR Balancing Account will be credited to the yearly CRR Balancing Account.

If the net CRR shortfall for the month exceeds the revenue in the monthly CRR Balancing Account, all CRR monthly payment and charge shortfalls will be partially paid/charged based on the ratio of the available funds in the CRR Balancing Account for the month divided by the month's total hourly net shortfalls (net of revenue shortfalls and charge shortfalls). Any remaining shortfalls will be carried forward for the end-of-the-year clearing (true up).

Q. Can you provide an example to illustrate how the monthly clearing of the CRR Balancing Account works?

A. Certainly.

Example V.1 - Monthly Clearing of CRR Balancing Account:

Assume there are a total of three CRR Holders. As a result of Congestion revenue inadequacy during some hours of the month, CRR1 and CRR2 did not receive full payment for their CRRs and CRR3 was undercharged during the month. The total monthly net shortfall as the sum of the hourly underpayments/undercharges for the month are as follows:

- CRR1 Payment Shortfall for the month = $1,000
- CRR2 Payment Shortfall for the month = $1,500
- CRR3 Undercharges for the month = -$600

The total shortfall in the month is the net of underpayment and undercharges for all the hours within the month = 1,000 + 1,500 – 600 = $1,900

Let us consider three different situations at the end of the month:

Scenario a: Adequate Funds in the CRR Balancing Account

Assume the balance in the CRR Balancing Account for the trade month is $2000. Since the shortfall is $1,900, the funds in the Balancing Account are sufficient to true up the CRR Payments and charges to the full. CRR Holders' payment shortfalls are paid in full (CRR1 and CRR2) and the counterflow CRR Holders are charged in full (CRR3) for the month. The results are shown in the following table:

	CRR1	CRR2	CRR3	Total
Payment/Charge Shortfall During the Month	$1,000	$1,500	-$600	$1,900
Monthly Payment/Charge	$1,000	$1,500	-$600	$1,900
Remaining Shortfall	$0	$0	$0	-
Starting Balancing Account				$2,000
Ending Balancing Account				$100

The additional $100 is kept in the Balancing Account for yearly clearing.

Scenario b: Insufficient Funds in the CRR Balancing Account

Assume the balance in the CRR Balancing Account for the trade month is $1,520. Since the shortfall is $1,900, the funds in the Balancing Account are not sufficient to true-up the CRR Payments and charges to the full. A monthly true up ratio is computed as follows:

- Month's true-up ratio = (Funds in Balancing Acct. for the month) / (total net monthly shortfall)
- True-up ratio for the month = $1,520/ $1,900 = 80%
- The CRR Payments and charges are scaled accordingly, as follows
- CRR1 Payment shortfall for the month = $1,000.
- Pay CRR1: 80% ($1,000) =$800
- CRR1's un-recovered shortfall for the month = $200
- CRR2 Payment shortfall for the month = $1,500.

- Pay CRR2: 80% ($1500) =$1,200
- CRR2's un-recovered shortfall for the month = $300
- CRR3 undercharges for the month = $600.
- Charge CRR3: 80% ($600) = $480
- CRR3 adjusted undercharge amount for the month =$120

The results are summarized in the following table:

	CRR1	CRR2	CRR3	Total
Payment/Charge Shortfall During the Month	$1,000	$1,500	-$600	$1,900
Monthly Payment/Charge	$800	$1,200	-$480	$1,520
Remaining Shortfall	$200	$300	-$120	$380
Starting Balancing Account				$1,520
Ending Balancing Account				$0

The remaining shortfall payments and undercharges are carried over for yearly clearing.

Scenario c: No Funds in the CRR Balancing Account

In this case no adjustments are made until yearly clearing.

Q. How does the annual clearing of the CRR Balancing Account work?

A. If the net CRR shortfall for the year is less than the revenue in the yearly CRR Balancing Account, all CRR yearly payment and charge shortfalls will be fully paid and charged and the net payment will be debited to the yearly CRR Balancing Account. The remaining revenue in the yearly CRR Balancing

Account will be paid to the PTOs in proportion to their TRR over the one-year CRR term.

If the net CRR shortfall for the year exceeds the revenue in the yearly CRR Balancing Account, all CRR yearly revenue and charge shortfalls will be paid and charged pro rata based on the ratio of available funds in the CRR Balancing Account divided by the total of unrecovered shortfall (net of remaining revenue shortfalls and remaining charge shortfalls) for the year. No additional payments or charges will be made. Both the unpaid amounts and the uncharged amounts become ineligible for further recourse and will be written off after the yearly clearing process. Also, in this case, there will be no credits or debits towards the PTOs' TRR.

Q. Can you provide an example to illustrate how the annual clearing of the CRR Balancing Account works?

A. Certainly.

Example V.2 – Annual Clearing of CRR Balancing Account:

Assuming that during the trade year, the CRR Holders had unrecovered revenue shortfall/undercharges for 2 months (Month 1 and Month 2) during the year as shown in the following table:

Month	CRR Holder	Un-recovered Shortfall/Undercharge
1	CRR1	$800
	CRR2	$600
	CRR3	-$200 (undercharge)
2	CRR1	$300
	CRR2	$400
	CRR3	$100

The yearly net shortfall is the sum of the monthly net shortfalls. Adding up all the payment shortfalls and undercharges for the all the months in the year:

- CRR 1's shortfall for the year = $800 + $300 = $1100
- CRR 2's shortfall for the year = $600 + $400 = $1000
- CRR 3's undercharge for the year = -$200 + $100 = -$100

The total net shortfall for the year is the net of underpayment and undercharges for all the months within the annual CRR year = $1,100 + $1,000 – $100 = $2,000

Let us consider three different situations at the end of the year:

Scenario a: Adequate Funds in the CRR Balancing Account

Assume the balance in the CRR Balancing Account at the end of the year is $2,200. Since the net un-recovered annual shortfall is $2,000, the funds in the CRR Balancing Account are sufficient to true-up the shortfall. The CRR Holders' payment shortfall is paid in full and the counterflow CRRs are charged in full for the year. Any remaining surplus is paid to PTOs in proportion to their TRRs applicable to the CRR annual period. The results are shown in the following table:

	CRR1	CRR2	CRR3	Total
Payment/Charge Shortfall For the Year	$1,100	$1,000	-$100	$2,000
Payment/Charge for Annual True-Up	$1,100	$1,000	-$100	$2,000
Remaining Shortfall	$0	$0	$0	-
Starting Balancing Account at Year End				$2,200
Remaining Funds in Balancing Account				$200

The funds remaining in the Balancing account ($200) are paid to the PTOs.

Scenario b: Insufficient Funds in the CRR Balancing Account

Assume the balance in the CRR Balancing Account at the end of the year is $1,400. Since the net un-recovered annual shortfall is $2,000, the funds in the CRR Balancing Account are not sufficient to true-up the shortfall. Thus, the CRR Payment shortfall and the counterflow CRR undercharges are both reduced based on the Year's true-up ratio = (Funds in Balancing Acct. at year end) / (Total yearly net shortfall)

- True-up ratio for year = $1,400/ $2,000 = 70%
- CRR1 Payment shortfall for the year = $1,100.
- Pay CRR1: 70% ($1,100) =$770
- CRR1's un-recovered shortfall = $330
- CRR2 Payment shortfall for the year = $1,000.
- Pay CRR2: 70% ($1,000) =$700
- CRR2's un-recovered shortfall= $300

- CRR3 undercharges for the year = $100.
- Charge CRR3 for 70% ($100) = $70
- CRR3 adjusted undercharge =$30

The results are shown in the following table:

	CRR1	CRR2	CRR3	Total
Payment/Charge Shortfall For the Year	$1,100	$1,000	-$100	$2,000
Payment/Charge for Annual true Up	$770	$700	-$70	$1,400
Remaining Shortfall	$330	$300	-$30	$600
Starting Balancing Account at Year End				$1,400
Remaining Funds in Balancing Account				$0

There will be no additional true up for the CRR Holders, and no revenues will be available for PTOs.

Scenario c: No Funds in the CRR Balancing Account

In this case, no further adjustments are made to CRR payments and charges and no revenues will be available for distribution to the PTOs.

Q. Is there a difference between hourly, monthly or annual settlement of CRRs obtained through the allocation or auction?

A. No. It makes no difference if the CRR was obtained through the annual or the monthly allocation or auction for all practical Settlement purposes. Their treatment in hourly settlement, monthly true-up and annual true-up are the same. In any given hour any shortfall payment or receipt is applicable to the entity holding CRRs in that hour regardless of whether the CRR was obtained from annual or monthly process or in the secondary market.

Note: The difference between how CRR was obtained (from CRR allocation or auction or secondary market) and its seasonal or monthly nature will be tracked for the following purposes that are unrelated to CRR settlements:

1. Grandfathering for allocated CRRs. Note that only CRRs acquired in the annual allocation (not auction) process can be grandfathered, and if CRRs are traded, the grandfathering privilege remains with the allocated LSE; it does not get transferred with the secondary transfer of CRRs.
2. The auction price (of primary interest to Market Monitoring).
3. Credit posting for the term of counterflow CRRs.

Q. Can CRRs be traded?

A. Yes. CRRs may be traded regardless of whether they were acquired through CAISO's CRR Allocation or CRR Auction process. CRR trades in the secondary market are allowed in daily blocks, separately for peak- and off-peak periods.

Regardless of whether CRRs were obtained through the allocation or the auction process, the CRR Holder can break up the seasonal CRRs into monthly CRRs, or break up both the seasonal and monthly CRRs into daily CRRs or any interval in between in units of whole days as defined by the TOU period of the CRR. The

CRR Holder can also break up the total amount of CRRs it has from any source to any sink and trade them in denominations down to 0.1 MW increments if it so wishes. However, the CRR Holder cannot break up a CRR from source A to sink B into two CRRs from A to C and C to B.

The CAISO does not facilitate secondary market trade of CRRs; however such trades must be reported to the CAISO for proper credit or charge to the CRR Holder. Since CRRs traded may entail liabilities (counterflow CRRs), registered secondary transfers will be on hold until creditworthiness of the transferee is verified or established, to minimize the risk that transfer of counterflow CRRs will not cause revenue shortfall due to default.

Q. What LDFs will be used for pricing the LMP of a Load zone for purposes of CRR settlements?

A. In Release 1, the CAISO will use the same LDFs used in the IFM to settle with CRR Holders having a Load zone as the CRR sink. As a result, if the schedules and CRRs are consistent, the Energy market settlement and CRR settlement will be settled based on the same LDFs for the Load zone sink. However, since the LDFs used for the CRR Simultaneous Feasibility Test (SFT) are not the same as the LDFs used to pay the CRR Holders, this method of Load zone pricing for CRR settlements, may increase the risk of hourly Congestion revenue inadequacy to pay CRR entitlements.

In MRTU Release 2, the CAISO will consider applying the LDFs used during the CRR release for the Load zones to settle with CRR Holders. This will improve CRR revenue adequacy. However, under this approach even if the schedules and CRRs are consistent, the Energy market settlement and CRR settlement could be settled based on different Load zone LDFs and thus different effective prices; the CRR Holder could be paid higher or lower than the amount charged for Congestion associated with its Energy settlement in the Day-Ahead Market.

Q. What weights will be used for pricing Trading Hubs for purposes of CRR settlement?

A. The CAISO will use two sets of on-peak and off-peak weights for each season based on the metered Generation output of all generating resources included in the hub definition from a prior period. The CAISO will be using the same weights for settling both CRRs and Energy at the Trading Hubs.

Q. How are Multi-Point CRRs settled?

A. Multi-Pont CRRs are settled based on 1) the sum of the CRR MW at each sink multiplied by the corresponding sink's MCC, minus 2) the sum of the CRR MW at each source multiplied by each source's corresponding MCC.

Note that Multi-Point CRRs will be offered as CRR Obligations only. In the case of hourly net Congestion revenue shortfall, the Multi-Point CRR payments/charges will be prorated.

Q. Will CRRs hedge against marginal losses?

A. No. CRRs will hedge against Congestion costs only.

Q. Why are CRRs not used for hedging against marginal losses?

A. The CRR product as currently designed is based on balanced source and sink MWs. Using such CRRs to hedge both Congestion and marginal losses would result in revenue deficiency for CRR Holders. Theoretically, it is possible to design a different type of (unbalanced) CRRs to hedge against both Congestion and marginal losses, but such CRRs are in experimental stage.

VI. ANCILLARY SERVICES PROCUREMENT, PRICING, PAYMENT AND COST ALLOCATION

A. Ancillary Services Requirements

1. Ancillary Services Products

Q. What are the Ancillary Services that the CAISO will procure under MRTU?

A. The CAISO will procure Regulation, consisting of Regulation Up and Regulation Down, Operating Reserves consisting of Spinning Reserve and Non-Spinning Reserve, as well as Voltage Support and Black Start Capability. Regulation and

Operating Reserves are procured in the CAISO spot markets (IFM, and incrementally as needed in HASP and Real-Time)and are procured based on a resource ramp time of 10 minutes; Voltage Support and Black Start Capability will be procured via long-term contracts rather than in the Day-Ahead and shorter-term markets.

Q. How will the CAISO determine the amount of each Ancillary Service to procure under MRTU compared with its present procurement practices?

A. Under both the CAISO's current market design and MRTU, Regulation Up and Regulation Down are needed for Automatic Generation Control ("AGC"). The CAISO must have sufficient generating capacity under AGC in order to continually balance generation in response to Western Interconnection frequency changes (based on the frequency bias assigned to the CAISO) and to maintain interchange schedules with the CAISO's neighboring Control Areas.

The CAISO sets its Regulation reserve target as a percentage of CAISO Demand Forecast (Demand Forecast excluding Exports) for the hour based upon its need to meet the WECC and North American Reliability Council ("NERC") performance standards (primarily CPS1 and CPS2). However, the percentage targets can be different for Regulation Up and Regulation Down. The percentage targets can also vary based on the hour of the operating day. The CAISO's Regulation targets (in MWh) may change if its Load forecast changes after running the Day-Ahead Market.

With respect to the procurement of Operating Reserves, the CAISO will continue, under MRTU, to set its procurement target in accordance with WECC MORC (Minimum Operating Reliability Criteria) requirements. Currently, based on these standards, the CAISO procures Operating Reserves equal to the greater of (a) 5% of the Demand (less net firm Imports) met by hydroelectric resources, plus 7% of the Demand (less net firm Imports) met by thermal resources, or (b) the single largest Contingency. In practice, the former (quantity of Operating Reserves based on percentage of Demand) is greater and sets the requirements system-wide. However, if the CAISO must target procurement of Operating Reserves on a more granular basis, such as AS sub-regions, discussed below, the latter criteria (quantity of Operating Reserves based on the largest contingency) could drive the procurement of Operating Reserves in one or more of the smaller regions. In addition, under the current standards, at least 50% of the Operating Reserve requirement must be met by Spinning Reserves, and no more than 50% of the Operating Reserve requirements may be met from Imports of AS. Moreover, the quantity of AS Imported from a single tie may be limited to 25% of the total system-wide AS requirement, at the operator's discretion.

The CAISO will continue, under MRTU, to follow these practices or whatever other WECC standards may replace them by the time MRTU is implemented.

Also, under MRTU, as today, the quantities of Regulation Up, Regulation Down, and Operating Reserves that the CAISO targets for each hour of the operating day will be published as part of the Public Market Information (PMI) by 6:00 p.m. two days prior to the operating day.

Q. You did not list Replacement Reserve as one of the Ancillary Services that the CAISO will procure under MRTU. What will serve the role, under MRTU, of the capacity that the CAISO previously procured as Replacement Reserve?

A. Replacement Reserve was not among the Ancillary Services that FERC required transmission providers to procure under Order No. 888 and Order No. 2000. However, it was included as part of the initial CAISO market design, in the absence of Resource Adequacy requirements and a must-offer obligation ("MOO"), as insurance that there would be adequate capacity in Real-Time to the extent that CAISO operators could not rely on Supplemental Energy Bids to satisfy 100% of the Real-Time system needs within a comfortable margin. The MOO, instituted by FERC in 2001 ("FERC MOO") made it unnecessary for CAISO to procure Replacement Reserves. Under MRTU, the Resource Adequacy must-offer Obligation ("RA-MOO") will serve the same function, and likewise make it unnecessary for the CAISO to procure Replacement Reserves. Moreover, the RUC function will greatly enhance cost-effective use of resources, and replace the current must-offer Waiver Denial process that is in place in conjunction with the FERC MOO.

A secondary function of the Replacement Reserve was to replenish Operating Reserves that were used to produce Energy in Real-Time. However, because Replacement Reserve was a 60-minute product, there was no guarantee that it would necessarily include adequate 10-minute responsive capacity that would be substitutable for Operating Reserves.

Q. Some ISOs have a "slower" (30-minute) Operating Reserve product in addition to 10-minute Operating Reserves. Did the CAISO consider including such a product in the MRTU design?

A. Yes, but not for the initial MRTU implementation (Release 1). However, the CAISO plans to explore the possible inclusion of a 30-minute Operating Reserve product in MRTU Release 2.

2. Ancillary Service Regions

Q. How, under MRTU, will the CAISO procure Ancillary Services in order to meet local Ancillary Services requirements, as compared to its current market design?

A. Under MRTU, the CAISO will calculate and procure AS primarily for the entire CAISO Control Area. However, the CAISO will, at the same time, take into account the minimum amount of AS that is needed within specific areas in the CAISO Control Area (usually Load pockets) as well as the amount of AS above which it would not be prudent to concentrate the Supply of AS in one area (usually Generation pockets and imports). The extent to which the locational dispersion of AS Supply may be enforced by the CAISO (*i.e.*, treated as binding constraints) depends on the locational spread of Demand within the Control Area, regional transmission limitations, available transmission capacity, transmission outages, the locational mix of Generation, and Generation outages.

Under the CAISO's current market design, AS requirements are determined for the entire Control Area. If the Ancillary Services procurement software procures a disproportionate amount of AS in one zone, the procurement is repeated based on a zonal split. A market notice is issued when the split zones are used for AS procurement. The zonal split is usually between NPZP (*i.e.*, the combination of zones NP15 and ZP26) on one side and SP15 on other side.

In contrast, under MRTU, the zonal boundaries (AS regions) and limits (minimum or maximum AS from each AS region) will be included in the Bid Cost optimizing market clearing process, and the procurement in each region will be accomplished automatically through the enforcement of the AS regional and Intertie constraints.

Q. What are Ancillary Services Regions?

A. Broadly speaking, an AS Region is an area of the power system for which AS requirements will be specified under MRTU. More precisely, the quantity (MWh) of each AS product to be procured from resources in each AS region must not be below (or above) a specific amount. Stated differently, each AS Region will include a collection of resources certified to provide AS, along with a lower bound specifying the minimum amount of AS that must be procured from those resources, or an upper bound specifying the maximum amount of AS that may prudently be procured from those resources. AS Regions may or may not be mutually exclusive, *i.e.*, a resource may belong to more than one AS Region.

Q. What are the AS Regions that will exist at the time of MRTU implementation?

A. Under MRTU, the two primary AS regions will consist of: 1) the System Region, which is defined as the entire CAISO Control Area; and 2) the Expanded System

Region, which consists of the entire CAISO Control Area, along with the Import Scheduling Points.

However, the CAISO will also have the ability, under MRTU, to create new AS Regions, if the CAISO determines that it is necessary to procure AS on a geographically more granular basis. Initially, with the implementation of MRTU,the Sub-Regions will be the same as the existing transmission zones (*i.e.*, NP15, SP15 and ZP26). In addition, the CAISO will have the authority to modify the boundaries of the AS Regions. If the CAISO establishes Sub-Regions or changes the use of existing Ancillary Service Regions, it will issue a Market Notice as soon as reasonably practicable after the occurrence of circumstances that leads the CAISO to establish Sub-Regions or change the use of existing Ancillary Service Regions. If for example, the circumstance leading to a change is an extended planned outage of a transmission line or generating resource, the CAISO notice can be prior to submission of Bids in the Day-Ahead Market on the day in which the outage is to occur. If a transmission outage or Generating Unit outage is a Forced Outage, the CAISO will give notice of any change in the use of Ancillary Service Regions as soon as reasonably practicable after the occurrence of the Forced Outage.

Q. What are the criteria that the CAISO will employ for adjustment of AS Regions?

A. The CAISO's decision to adjust the boundaries of existing AS Regions, or to create new AS Regions, will be based on operational reliability needs.. Specifically, the CAISO will consider such factors as the locational spread of Demand within the Control Area (e.g., differential Load growth), Generation or transmission additions, changes in regional transmission limitations, changes in the available transmission capacity, and extended transmission or Generation outages. However, with respect to AS Regions with minimum AS requirements (*i.e.* Load pockets), in addition to the factors I just listed, market power issues must also be considered in deciding whether or not to create a more granular AS Region. This is because under MRTU, there will be no local market power mitigation for AS (other than the system-wide AS Bid cap). Therefore, creating a more granular AS region within a region that qualifies as a Load pocket has the potential to allow resources within that region to exercise market power.

Q. Can AS Regions overlap?

A. Yes. AS regions can be mutually exclusive or nested, meaning that one region may be entirely included as part of a larger region. For example, the zones SP15, ZP26, NP15, and the Interties may be defined as AS Regions under MRTU. These are mutually exclusive AS Regions, in that they have no overlap. However, an NPZP region could be defined as a "Northern" AS Region encompassing both

NP15 and ZP26 zones. Also, as I explained previously, there is a System Region defined to include all AS certified resources internal to the CAISO Control Area, and there is also the Expanded System Region which consists of the System Region as well as the certified system resources outside the CAISO Control Area. Given these AS Region definitions, NP15, NPZP, the System Region, and the Expanded System Region are nested, *i.e.*, one is entirely included in another. If necessary, for the reasons I described earlier, other AS Regions can be defined within the CAISO Control Area as Sub-Regions of the System Region as long as they are either mutually exclusive or nested within other previously defined AS Regions. For example, the Los Angeles basin could be defined as an AS Region, in which case it would be wholly encompassed by the SP15 Region, which is in turn in the System Region, which itself is in the Expanded System Region.

Theoretically, the CAISO could also create partially overlapping AS Regions. However, such AS Regions are not expected to be needed, and as I will discuss later, will be avoided if possible. For example, it would not be advisable to define both a ”Southern” region (SPZP) consisting of SP15 and ZP26, and a ”Northern” region (NPZP), consisting of NP15 and ZP26, because they would overlap only partially (both would include resources in ZP26). Only one of NPZP or SPZP should be defined as an active AS Region.

Q. Would AS procured in a Sub-Region count towards the AS requirement for the larger Region in which it is nested?

A. Yes. In the case of nested (or overlapping) Regions, the capacity procured in the lowest granularity region (e.g. ZP26), would count towards the AS requirement for the larger (e.g., NPZP) region, but not vice versa.

Q. Can a resource Supply AS in more than one AS Region?

A. Yes, a resource can Supply AS to more than one Region in the sense that that capacity would count towards satisfying the minimum AS procurement requirement for multiple regions, as stated in response to the previous question. Capacity from a single resource can satisfy the AS requirement for multiple regions if the regions are nested. For instance, a resource in ZP26 may satisfy requirements for several AS regions, including ZP26, NPZP (NP15 plus ZP26), the System region, and the Expanded System Region.

3. AS Self-Provision and Trade

Q. Under MRTU is it possible for resources to Self-Schedule AS, that is, to offer to sell AS as a price taker without submitting a Bid price?

A. Yes. Under MRTU, resources will be permitted to schedule AS as price takers by Self-Providing AS. The information submitted to Self-Provide AS under MRTU is referred to as a "Submission to Self-Provide an Ancillary Service" as opposed to describing the submission as a "schedule to Self-Provide" (generally "schedule" is used to refer to something issued by the CAISO and not information submitted to the CAISO). The term "Self-Provided Ancillary Services" refers to a Submission to Self-Provide that has been accepted by the CAISO. Acceptance means the CAISO has determined the submission is feasible with regard to resource operating characteristics and regional constraints and is qualified to provide the Ancillary Service in the market for which it was submitted. In this testimony, an accepted Submission to Self-Provide AS will be referred to as either Self-Provided Ancillary Services or "qualified Self-Provision."

Q. Can resources Self-Provide AS for all services and in all markets?

A. Under MRTU, resources will be permitted to Self-Provide the four reserve services (Regulation Up, Regulation Down, Spin, and Non-spin), but not Voltage Support and Black Start Capability. Moreover, resources will be able to Self-Provide AS in both the IFM and in the Real-Time Market. However, the Real-Time AS procurement process will accept Submissions to Self-Provide AS only to the extent that incremental procurement of AS is needed in Real-Time to satisfy any AS shortfall from the Day-Ahead time frame.

Q. Will there be any limits on the amount of AS that can be Self-Provided?

A. Yes. There will be a limit on the total amount of Self-Provided AS in that the total amount of Self-Provided AS by all SCs in an AS Region cannot exceed the corresponding AS Region maximum limit. If it does, then the amount of Self-

Provided AS in the constrained AS region will be reduced pro rata among the SCs Self-Providing AS from resources with the constrained AS Region. The amount of AS that can be Self-Provided by a SC in accordance with this limitation is referred to as the "qualified Self-Provision" amount in this testimony.

Q. How will qualified Self-Provided AS be treated vis-à-vis AS Bid into the CAISO markets?

A. In the MRTU integrated market clearing process, qualified Self-Provided ASwill be treated with a higher priority than AS that is Bid into the markets. Moreover, qualified Self-Provided AS is not eligible to set the AS Market Clearing Price (ASMP) and does not receive the ASMP. Instead, any qualified Self-Provided capacity offsets a portion of the AS obligation of the Self-Providing SC and decreases the amount of AS that the CAISO purchases in the Energy-AS co-optimization process.

Q. Will an SC be permitted to Self-Provide AS in excess of its own AS obligations? If so, how will this excess capacity be treated?

A. Although the total of all qualified Self-Provided AS cannot exceed the total CAISO requirement for that service, an individual SC may end up with an amount of qualified Self-Provided AS that exceeds that SC's own AS obligations. Any such excess qualified Self-Provided AS is paid an average AS price, referred to as the "user rate," for that service. I will, later in my testimony, describe in detail how the CAISO calculates the user rate for Ancillary Services.

Q. Will SCs be permitted to Self-Provide AS from imports?

A. Not initially. Although AS imports will be accommodated in MRTU, the initial MRTU software Release 1 will limit AS Self-Provision to internal resources. MRTU Release 1 will not accommodate Self-Provision of AS from the Interties for any of the MRTU markets (IFM, HASP, or Real-Time), for all entities. The reason for this limitation is primarily software-related, and the CAISO plans to explore the merits of including this functionality as part of MRTU Release 2. SCs that would otherwise plan to satisfy their AS obligation through self-provided AS imports will have the option of, instead, Bidding their AS imports into the market at $0 (or a negative) price.

Q. What is the difference, under MRTU, between an SC Self-Providing AS and Bidding AS at $0?

A. There are three main differences:

(1) Although AS Bids must be accompanied by Energy Bids (as I discuss in more detail below), an SC Self-Providing AS does not have to submit an Energy Bid in the IFM for the Self-Provided AS capacity, but can instead submit an Energy Bid in HASP/Real-Time. However, an SC Bidding AS (even when Bidding at $0 for AS capacity) must submit an Energy Bid.

(2) Because Energy and AS are co-optimized, an AS Bid of $0 may still lose to (*i.e.*, not be selected in lieu of) a higher-priced AS Bid (e.g. $2). This is because the MRTU optimization process, which determines which AS Bids are selected, is not based on AS Bid costs alone, but implicitly includes the sum of the AS Bid price and the Energy opportunity cost for the resource. I discuss this concept in greater detail later in this section.

(3) Self-provided AS reduces an SC's AS obligation, but an AS award based on a Bid price (even a $0 Bid price) does not. To understand the meaning of this difference in practice, consider an entity with a Load of 100 MW. Assume that that SC's AS obligation is 7% of its Load. Thus, the SC's obligation is 7 MW. If the SC Self-Provides 5 MW of AS, it is charged for only 2 MW of AS at the AS user rate. Assume the user rate is $10/MW/h. The net charge to the SC is thus $10 * 2= $20. However, if the SC instead Bids in the 5 MWs of its AS at $0, and that Bid is selected, it is paid the ASMP (assume an ASMP of $8/MW/h). The SC is therefore paid the total of $8 * 5 = $40, but it is, in turn, charged for 7 MW of AS at the user rate, *i.e.*, $10 * 7 = $70. Thus, in this example, the SC that cannot Self-Provide but attempts to replicate Self-Provision by Bidding in at $0 the capacity that it would have otherwise Self-Provided has a net charge of $30. Whereas the entity that can Self-Provide faces a smaller net charge of $20. It is important to understand, however, that this result is contingent on the relationship between the applicable ASMP and the user

rate. If, in the example just provided, the ASMP happened to be higher (say, $12/MW/h), the SC would have been paid $12 * 5 = $60 by selling the AS capacity, rather than Self-Providing that quantity, and therefore its net charge would have been $70 - $60 = $10 (instead of $20 when it Self-Provided). In other words, depending on the relationship between the ASMP and the user rate, a Self-Provider may end up paying more or less than an entity Bidding its capacity into the AS market as a price taker (*i.e.*, Bidding a $0 or negative price).

Q. Will an SC be permitted to Self-Provide AS in any Region regardless of where the entity has its AS obligation(s)?

A. Yes. An SC's qualified Self-Provided AS, that is not subsequently withdrawn or otherwise subjected to AS "No Pay" provisions, will count towards satisfying that SC's AS obligation for that service regardless of which AS region it is supplied from. However, as stated earlier, MRTU Release 1 limits Self-Provision to resources within the CAISO Control Area.

Q. Will the MRTU market design permit AS to be traded between SCs, and if so, how?

A. Yes. As with the CAISO's existing market design, under MRTU, SCs will be able to trade AS among themselves. These trades must be for a fixed quantity of AS (e.g., 10 MW of Spinning Reserve) and for a single hour or block of hours.

These trades are financial transactions between SCs, with a net zero sum impact on the CAISO's AS requirements or procurement targets. The result of such a trade will be, for the trade period, to increase the net AS obligation of the seller, and reduce the net AS obligation of the buyer, for the traded service and quantity.

B. <u>Ancillary Services Pricing</u>

1. Ancillary Services Bids

Q. What are the components of an AS Bid?

A. An AS Bid is a capacity offer in dollars per Megawatt per hour ($/MW/h). Unlike an Energy Bid, which consists of a multi-segment price/quantity curve, an AS capacity Bid consists only of a single price. The quantity and price may be different for each Trading Hour, each market, and each service.

A resource may both self-provide (subject to the qualification rules pertaining to AS self provision) and Bid AS from the same resource in a given Trading Hour as long as the total amount of AS capacity from the resource, including both self-provided and Bid quantity, does not exceed the applicable certified maximum AS capacity of the resource. Resources must specify through a flag whether their Spinning and Non-Spinning awards are to be treated as contingency reserve, *i.e.*, whether they will be available for Real-Time Dispatch under contingency conditions only, or whether they can be Dispatched optimally in Real-Time under all conditions. The contingency flag is ignored in the IFM market-clearing process, and does not affect AS procurement. It is only considered for purposes of Energy Dispatch in Real-Time.

Q. Will resources be permitted to submit a contingency flag only for specific hours during a Trading Day?

A. Not initially. Under MRTU Release 1, a resource that wishes to have its Spinning and Non-Spinning AS Bids treated as contingency reserves must do so for all Trading Hours of the applicable Trading Day.

Q. How will the CAISO choose which AS Bids to award under MRTU?

A. AS Bids will be evaluated simultaneously with Energy Bids. Therefore, capacity from resources not already scheduled, for which both Energy and AS Bids are submitted, will be selected optimally either for an Energy Schedule (or Dispatch) or for provision of AS. In the Day-Ahead IFM, this applies to resource capacity not already Self-Scheduled for Energy or used for qualified AS self-provision. In HASP/Real-Time, this will apply to resource capacity not already awarded an Energy or AS Schedule in the Day-Ahead IFM or incrementally Self-Scheduled for Energy in HASP.

For example, in the Day-Ahead IFM, AS Bids will be evaluated simultaneously with Energy Bids to clear Bid-in Supply and Demand, and to meet the AS requirements net of qualified AS self-provision, subject to all transmission constraints for Energy, and the tie and AS regional constraints for AS. In this process, both the LMPs for Energy and the ASMPs are determined.

Q. Will resources be required to submit Energy Bids along with AS Bids?

A. Yes. Under MRTU, all AS Bids must be accompanied by an Energy Bid, in order for the AS Bid to be considered in the AS selection process (which is part of the simultaneous Energy, AS, and Congestion market clearing process). The only exception to this rule is AS that is self-provided in the Day-Ahead IFM, for which an Energy Bid must be submitted later, specifically, in the HASP/Real-Time Bid submission timeframe.

Q. You mentioned that the "contingency flag" will be ignored in the IFM clearing process. You also stated that resources will be required to Bid in Energy along with AS Bids. Given these constraints, how can a resource, such as a hydro or other use-limited resource, that wishes to provide contingency-only Operating Reserves, but not Energy, participate in the IFM?

A. Such a resource will have two options. First, it can self provide contingency-only AS in the IFM. Second, it can Bid in AS, but submit a daily Energy limit of 0 MWh in the IFM (the concept of daily Energy limits is explained in the testimony of Dr. Kristov).

Q. Please describe how Ancillary Services Marginal Price ("ASMPs") will be calculated.

A. Generally speaking, under MRTU, the ASMP for a given service at a given "location" will be the cost of procuring an increment (MW) of that service at that location. It should, however, be understood that the use of the word "location" here is not entirely precise because the "locations" where AS requirements are defined are AS Regions, whereas ASMPs are determined for individual nodes. This is a somewhat academic distinction, however, because in practice all nodes belonging to exactly the same set of AS regions (*i.e.*, located within the intersection of multiple AS regions) have the same ASMP. To better understand this statement, consider the Expanded System Region along with all of the AS Regions. Because some AS regions have common areas (are nested), collectively they divide up the Expanded System Region into non-overlapping smaller areas. The ASMP for all nodes within each of these smaller areas is the same.

ASMPs can be described more precisely in terms of "Regional Ancillary Service Shadow Prices ("RASSPs")." RASSPs are produced as a result of the co-optimization of Energy and AS for each AS Region, and represent the cost sensitivity of the relevant binding regional constraint at the optimal solution, *i.e.*, the marginal reduction of the combined Energy-AS procurement cost associated with a marginal relaxation of that constraint. If neither of the constraints (upper or lower bound) is binding for an AS Region, then the corresponding RASSP is zero. The ASMP for a given service at a particular node is the sum of all RASSPs for that service over all AS regions that include that node. It thus follows that all resources located in exactly the same set of AS Regions (or more precisely, all resources located in the mutually exclusive sets defined by the Boolean intersection of AS Regions), will have the same ASMP. For example, if the defined AS Regions consist of NP15, ZP26, SP15, the System Region, the interties, and the Expanded System Region, then all resources within NP15 will have the same ASMP, as will all resources within SP15 and all resources within ZP26.

The ASMP so computed at each node for each service will not be lower than the highest accepted AS Bid for that service from any resource at that node. In fact, the ASMP would also reflect any lost opportunity costs associated with keeping the resource capacity unLoaded for AS instead of scheduling that capacity as Energy in the same market.

Q. How will Congestion on an intertie impact the ASMP for resources Bidding in AS over that intertie?

A. If the intertie is not defined by itself as an AS Region, or if it is so defined but neither the upper nor the lower bonds on that intertie AS region are constraining, then the ASMP at the intertie reflects the result of economic competition between AS and Energy Bids in using the intertie's limited transmission capacity. In such a case, the ASMP at the intertie will include an Energy opportunity cost that does not reflect the reduction of the LMP at the tie due to Congestion, *i.e.*, assigns a higher opportunity cost than the difference between the LMP at the tie and the resource's Energy Bid price. This increased opportunity cost is really the shadow price of the congested intertie. The shadow price of a congested intertie is the cost sensitivity of the binding intertie constraint at the optimal solution, *i.e.*, the marginal reduction of Energy-AS procurement costs associated with a marginal relaxation of that constraint. AS awards from intertie resources are charged explicitly for the marginal cost of intertie congestion at the relevant intertie shadow price.

Q. Please explain how the CAISO will take into account AS Bid prices and Energy opportunity costs in selecting the AS suppliers. In particular, will the CAISO ensure that the AS supplier with the lowest AS Bid price or lowest opportunity costs is selected?

A. The selection of AS providers will be based on the combination of AS Bid prices and the Energy opportunity costs, rather than each in isolation. The sum of the two is implicitly considered in the joint optimization of Energy and AS. Indeed, the ASMP represents the sum of the AS Bid price and the Energy opportunity costs of the marginal resource. ASMPs are marginal prices but the determination of the marginal resource is based on a co-optimization of Energy and AS.

Therefore, the fact that a particular resource has a lower AS Bid or lower opportunity costs relative to another resource at the same location does not necessarily mean that it will be selected. A resource with a low AS Bid price may lose to a resource with a higher AS Bid price at the same location if the former has a higher opportunity cost. Similarly, a resource with a low opportunity cost may lose to a resource with a higher opportunity cost if the former has a higher AS Bid price. In any case, the AMSP at each location can not be lower than the sum of the AS Bid price and the Energy opportunity cost of any resource selected (based on their Bids) to provide AS at that location.

Q. Can you please provide an example to illustrate this concept?

A. Yes.

Example VI.1 - Energy and AS co-optimization, Part I:

In order to focus on the issue at hand (*i.e.* the impact of AS and opportunity costs of Energy on the AS selection process), assume a single AS region, with no Imports, and consider only one service (e.g., Spinning Reserve), which is co-optimized with Energy. In addition, to further simplify this hypothetical example, assume no transmission Congestion, no losses, and vertical (price taker) Energy Demand.

Assume that the vertical Demand for Energy is 160 MW and that the AS requirement for the region in question is 20 MW. Assume further that there are only two 100 MW units A and B, each with an AS ramp rate high enough so that each can provide the entire 20 MW of required AS. Unit A has an Energy Bid of $30/MWh and an AS Bid of $2/MW/h. Unit B has an Energy Bid $35/MWh and an AS Bid $8/MW/h.

Since we are assuming that there is no transmission Congestion or losses, it follows that:

- Optimizing Energy alone would result in a solution with 100 MW of Energy from Unit A and 60 MW of Energy from Unit B. This would use all of the available capacity of Unit A for Energy, and result in Unit B Supplying all 20 MW of the required AS. Given this result, the total cost of Energy and AS would be equal to ($30 * 100 + $35 * 60 + $8 * 20) = $5,260.
- Optimizing the AS procurement first would result in obtaining the necessary 20 MWs of AS from Unit A alone since its AS Bid price is lower. This would decrease the amount of Energy that Unit A could provide, resulting in a cost of ($2 * 20 + $30 * 80 + $35 * 80) = $5,240 for the combined Energy and AS procurement.
- These are the two bookend solutions from the point of view of total costs. The costs associated with any other combination of

procuring the AS and Energy requirements from the two units in this example would necessarily fall in between these two solutions. Among the two, the least cost solution for procuring Energy and AS together (simultaneously) is the latter ($5,240 compared to $5,260).

- Therefore, the co-optimization of Energy and AS results in procuring 80 MW of Energy and 20 MW of AS from Unit A and 80 MW of Energy from Unit B. The marginal price of Energy is therefore $35/MWh, because that is the cost of meeting an additional MW of Load. The ASMP is the cost of procuring 1 more MW of AS. This would mean procuring 1 more MW of AS from unit A at $2/MW, but this would also require replacing 1 MW of Energy from Unit A with 1 MW of Energy from Unit B, with an Energy Bid cost increase of ($35 -$30) = $5/MWh. Therefore, the total cost of procuring 1 more MW of AS is $2 + $5 = $7. This total is the ASMP. Since there is one AS Region in this example, this is the ASMP at both locations of Units A and B.

The following table summarizes the Bids, market-clearing quantities and Market-Clearing Prices (LMPs for Energy and ASMPs for AS). Note that because there is no transmission congestion, and because losses are ignored, the Energy LMPs are the same at A and B:

Unit	Capacity (MW)	Energy Bid ($/MWh)	AS Bid ($/MW/h)	Energy Award (MW)	AS Award (MW)	LMP ($/MWh)	ASMP ($/MW/h)
A	100	$30	$2	80	20	$35	$7
B	100	$35	$8	80	0	$35	$7

Note that the ASMP is in fact the sum of the AS Bid from Unit A ($2) plus Unit A's opportunity cost of Energy (the difference between the Energy price of $35 and the unselected Energy Bid price of $30 for the unLoaded capacity of unit A reserved for AS). In general, the Energy opportunity cost implicitly considered in the co-optimization process is the difference between a resource's Energy Bid price and the Energy LMP at that pricing node.

Note also that the ASMP is still less than the AS Bid price of Unit B ($8), which is the reason why the AS Bid from Unit B was not selected in the co-optimization process.

Example VI.2 - Energy and AS co-optimization, Part II:

Assume that in the previous example the AS Bid from Unit B was $6/MW/h (instead of $8/MW/h). In that case, Unit B would have been selected instead of the $2/MW/h AS Bid from Unit A although Unit A has a lower AS Bid price. In other words, the $2 AS Bid from Unit A would have lost to the $6 AS Bid from Unit B. The following table summarizes the Bids and results in this scenario.

Unit	Capacity (MW)	Energy Bid ($/MWh)	AS Bid ($/MW/h)	Energy Award (MW)	AS Award (MW)	LMP ($/MWh)	ASMP ($/MW/h)
A	100	$30	$2	100	0	$35	$6
B	100	$35	**$6**	60	20	$35	$6

Q. Will the ASMP for each resource awarded AS be equal to the sum of the resource's AS Bid price and its Energy opportunity cost?

A. Not necessarily. The ASMP may actually exceed the sum of a resource's AS Bid price and the opportunity cost of the resource. In general, the ASMP is only equal to the sum of the AS Bid and the Energy opportunity cost of the marginal unit (*i.e.* the unit setting the ASMP). This ASMP is not lower than the sum of the AS Bid price and Energy opportunity cost from any other unit in the same location that was selected to provide AS during the same time interval. Stated differently, a unit for which the sum of its AS Bid price and Energy opportunity costs exceeds the ASMP would not receive an AS award.

In sum, the ASMP at the location of each resource that is selected based on its Bid price is at least equal to the sum of that resource's accepted AS Bid price and its Energy opportunity cost, but may be higher. This can be demonstrated by way of an example:

Example VI.3:

Assume that in addition to Units A and B in Example VI.1, a third Unit C with a 10 MW capacity submits an Energy Bid of $32/MWh and an AS Bid of $1/MW/h. Under the assumptions set forth in Example VI.1, Unit C would then have been selected to provide 10 MW of AS, with the remaining 10 MW of required AS coming from Unit A. The ASMP would still be set by Unit A at $7/MW/h. Thus, although the sum of Unit C's AS Bid price and Energy opportunity cost is $1 + ($35 - $32) = $4/MW/h, the relevant ASMP (used to pay Unit C for the AS that it provides) is $7/MW/h.

The following table summarizes the Bids and results in this case:

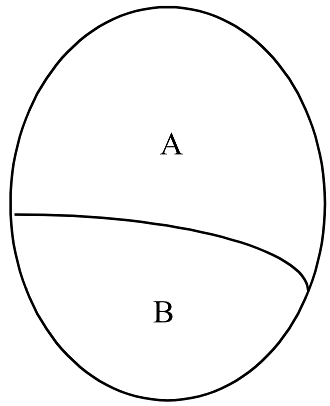
Unit	Capacity (MW)	Energy Bid ($/MWh)	AS Bid ($/MW/h)	Energy Award (MW)	AS Award (MW)	LMP ($/MWh)	ASMP ($/MW/h)
A	100	$30	$2	90	10	$35	$7
B	100	$35	$8	70	0	$35	$7
C	10	$32	$1	0	10	$35	$7

Q. Can you please expand on the concept of a RASSP that you mentioned above?

A. Yes. The process of Co-optimizing Energy and AS subject to AS Regional constraints will calculate a Regional Ancillary Service Shadow Price ("RASSP") for each AS Region, which as I noted earlier, represents the cost sensitivity of the relevant binding regional constraint at the optimal solution. The cost sensitivity is the marginal reduction of Energy-AS cost associated with a marginal relaxation of that constraint. If no regional constraint is binding for an AS Region, then the corresponding RASSP is zero. Because AS Regions may overlap or be nested, a resource may be located in several AS regions. The ASMP for a given resource for a given service is the sum of all RASSPs for that service for all AS Regions that include that resource. These concepts can best be illustrated by way of an example.

Example VI.4 - RASSP and ASMP Relationship:

Assume the Expanded System Region includes two AS Regions, A and B (e.g., NPZP and SP15; assume no interties), with a total AS requirement of 1,000 MW. Each Region must have at least 400 MW of AS procured from resources in that Region. Assume the AS Bids in Region A are all $5/MW/h and in Region B are all $15/MW/h. Assume there is adequate low cost Energy Bid from other resources so that the Energy opportunity cost of the resources Bidding to provide AS is $0. Given the last assumption, the minimum Bid Cost procurement of AS would need to consider only the AS Bid prices.



Designating the AS procured from the two Regions as RA and RB, the optimization problem is formulated as follows:

$RA + RB \geq 1,000$

$RA \geq 400$

$RB \geq 400$

Minimize the AS Bid cost: ($5 * RA + $15 * RB)

Obviously, if the RB constraint did not exist, all required AS could be procured from resources in RA for a total cost of $5 * 1,000 = $5,000. However, with the regional constraints as specified, the least cost solution is to procure 600 MW from Region A and 400 MW from Region B for a total Bid cost of $5 * 600 + $15 * 400 = $9,000.

To compute the AS regional constraint shadow prices, note that the binding constraints are those of the Expanded System Region (RA + RB) and the higher priced Region (RB).

- If the Expanded System Region constraint were reduced by 1 MW (*i.e*. 999 MW instead of 1,000 MW), the overall cost of procuring the necessary AS would decreased by $5. Thus, the RASSP for the Extended System Region is $5.
- If the constraint for Region B were reduced by 1 MW (*e.g*., 399 MW instead of 400 MW), it would allow procurement of 1 more MW from the lower cost Region A and 1 less MW from the higher cost Region B, with a net reduction of $15 - $5 = $10. Thus the RASSP for region B is $10.
- Increasing or reducing the 400 MW limit in the low priced region (RA) has no impact on the overall AS procurement cost. Therefore, the RASSP for Region A is $0.

Resources providing AS in Region A are included in both Region A and the Expanded System Region and thus their ASMP is the sum of the two RASSPs $0 + $5 = $5/MW/h. Resources providing AS in Region B are included in both Region B and the Expanded System Region and thus their ASMP is the sum of the two RASSPs, $10 + $5 = $15/MW/h.

Note that no resource selected to provide AS would be paid an ASMP below its accepted Bid price.

Q. If the RASSP is zero does this mean that AS suppliers will not receive capacity payments for the provision of AS?

A. No. If the RASSP is zero for an AS region, it does not mean that the ASMPs for resources within that AS region are zero. This is demonstrated in the previous example, in which the RASSP for region A is zero, but the ASMP for the resources within that region is $5/MW/h.

Q. Can a regional ASMP be negative?

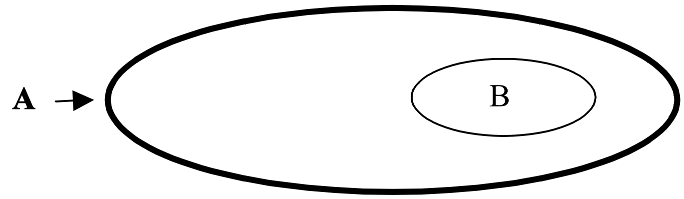
A. Yes, even with all AS Bids being positive, a RASSP can be negative.

Q. Can you provide an example demonstrating how a RASSP can be negative?

A. Yes.

Example VI.5:

Assume there are two AS regions A and B where B is a generation pocket inside A. Assume there are no other AS Regions. So A is, in fact, the Expanded System Region.



Assume the total AS requirement is 400 MW, but due to the generation pocket's transmission constraints, no more than 100 MW of AS may come from resources in B.

Assume all AS Bids from resources in Region A but outside of Region B are \$15/MW/h and all AS Bids from resources in Region B are \$5/MW/h. Assume that there is adequate low cost Energy Bid in from other resources, so that the Energy opportunity cost of the resources Bidding to provide AS is \$0. With the last assumption, the minimum Bid cost procurement of AS would need to consider only the AS Bid prices.

Designating the AS procured from the regions as RA and RB, the optimization problem is formulated as follows:

RA $\geq$ 400

RB $\leq$ 100

Minimize the AS Bid cost: [\$15 * (RA – RB) + \$5 * RB]

If the RB constraint did not exist, all AS could be procured from resources in RB for a total cost of $5*400 = $2,000. However, with the regional constraints as specified, the least cost solution is to procure 100 MW from Region B and 300 MW from resources in Region A outside Region B for a total Bid cost of $5 * 100 + $15 * 300 = $5,000.

To compute the regional constraint shadow prices, note that the binding constraints are those of the Expanded System Region (RA) and the low priced region (RB).

If the Expanded System Region constraint were reduced by 1 MW (*i.e.* 399 MW instead of 400 MW of required AS), the overall cost of procuring the necessary AS would decrease by $15. Thus, the RASSP for Region A is $15. If the low cost region constraint were reduced by 1 MW (99 MW instead of 100 MW), the overall cost would increase by $10, because this would mean procuring 1 less MW from Region B (with an associated cost reduction of $5), but it would also require procuring 1 more MW for the rest of Region A (at $15 cost). Because the change in the constraint limit (reduction) and the change in the minimum Bid cost (increase) have different signs, the RASSP for Region B is negative; in fact it is ($10) / (-1) = -$10/MW/h.

Note, however, that although the RASSP in Region B is negative, the ASMP for resources selected to provide AS in Region B is not negative. This is because resources in Region B are also in Region A, and their ASMP is the sum of the RASSPs of Regions A and B, *i.e.*, \$15 + (-\$10) = 5/MW/h.

Q. What will the suppliers of AS be paid for their awarded AS capacity?

A. Suppliers of AS (except for those that self-provide) are paid the ASMP at the location of the resource providing the relevant service. This includes AS Imports, however, AS Imports across congested interties are charged for Congestion.

SCs that self-provide AS in excess of their AS obligation are paid the "user rate" for that service. Finally, AS from Imports or non-firm Exports may be paid a fraction of the user rate to the extent that the quantity of AS behind firm Imports exceeds the CAISO's AS target quantity net of all qualified AS self-provision.

Q. Earlier you mentioned that a resource located within several AS regions satisfies the requirement of all those regions. You also stated that the ASMP is the sum of the RASSPs of the overlapping regions. Will that not result in a double payment to resources located in more than one AS Region?

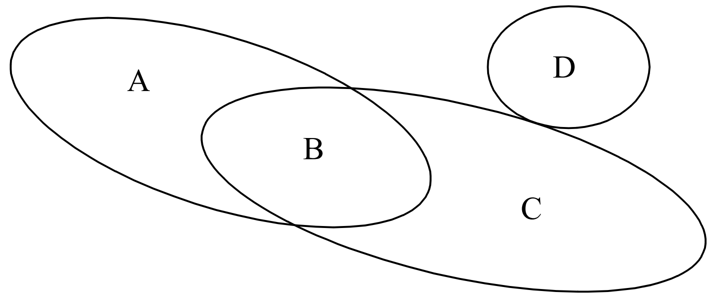
A. No. It is important to understand that the fact that ASMPs can be viewed as the sum of the RASSPs does not change the ASMPs themselves. Therefore, the fact that a resource is located in two different regions does not result in it receiving a double payment. In other words, in the same way that separating an Energy LMP into its system-wide, Marginal Loss, and Congestion components does not change the LMP itself, separating resource ASMPs into the relevant RASSPs does not impact the resource ASMPs.

Q. You stated earlier that partially overlapping AS Regions should be avoided if possible. Can you explain why?

A. Certainly. The CAISO's investigation of this issue shows no obvious need for overlapping AS Regions from an operational point of view. On the other hand, partially overlapping AS regions can increase AS costs. Therefore, they should be avoided unless absolutely needed due to operational requirements. To understand this concept, consider the following example.

Example VI.6 - Partially Overlapping AS Regions:

Assume there are four locations: A, B, C, and D (all of which are in the Expanded System Region). Let us define two AS Regions (in addition to the Extended System Region): AB consisting of areas A and B; and BC consisting of areas B and C. These Regions are configured as illustrated in the following diagram:



Assume that the total AS requirement for all of the areas is 1,000 MW, but at least 400 MW should come from each of the two AS regions AB and BC. Assume AS Bids at the four locations (areas) are as follows:

- A: 500 MW @ $20/MW/h
- B: 200 MW @ $10/MW/h
- C: 500 MW @ $20/MW/h
- D: 500 MW @ $5/MW/h

Assume there is adequate low cost Energy Bid in from other resources so that the Energy opportunity cost of the resources Bidding to provide AS is $0. With this assumption, the minimum Bid cost procurement of AS would need to consider only the AS Bid prices.

Designating the AS procured from the areas as RA, RB, RC, and RD the optimization problem is formulated as follows:

$RA + RB + RC + RD \geq 1,000$

$RA + RB \geq 400$

$RB + RC \geq 400$

Minimize procurement costs - ($20 * RA + $10 * RB + $20 * RC + $5 * RD)

Because the volume of AS Bids in RB is 200 MW, the least cost solution is RA = 200 MW, RB = 200 MW, RC = 200 MW, and RD = 400 MW. The resulting RASSPs are: RASSP (Expanded System Region) = \$5/MW/h, RASSP (AB) = \$15/MW/h, and RASSP (AC) = \$15/MWh. So the ASMPs are:

ASMP (A) = \$5 + \$15 = \$20

ASMP (B) = \$5 + \$15 + \$15 = \$35

ASMP (C) = \$5 + \$15 = \$20

ASMP (D) = \$5

The fact that location B is located in the partially overlapping AB and BC Regions results in an increased ASMP (\$35/MW/h) for resources providing AS at location B.

Q. Please explain the concept of AS service substitution (Rational Buyer), and describe how this concept will feature in the process of AS-Energy optimization?

A. The Rational Buyer concept was developed in order to reduce exposure to the potential exercise of market power associated with the sequential clearing of the AS markets under the existing (pre-MRTU) CAISO market design. The basic premise of the Rational Buyer concept is AS service substitution, *i.e.*, to allow procurement of a higher quality service as a substitute for a lower quality service when doing so would reduce the CAISO's overall AS procurement costs.

Such substitution will occur automatically in the simultaneous procurement of Ancillary Services under MRTU. More specifically, both under the current market design and under MRTU, Regulation Up can be used as substitute for Spinning and Non-Spinning Reserves, and Spinning Reserves can be used as substitute for Non-Spinning Reserves. However, it is important to underline an important distinction. Under the current design, the Rational Buyer objective is to minimize the total "payment" to suppliers of AS, whereas under MRTU the objective is to minimize the total co-optimized Bid Costs.

Q. How does Rational Buyer service substitution affect the prices for the superior service and the inferior service under the current (pre-MRTU)market design, and under MRTU?

A. When a higher quality service is used to satisfy the requirement for a lower quality service, generally the result is that the marginal Bid price of the higher quality service increases and that of the lower quality service decreases. Under the existing (pre-MRTU) design methodology, which focuses on minimizing total payments for AS, service substitution may stop before the marginal prices are aligned (price alignment means that the marginal price of the lower quality service is not higher than that of the higher quality service). For example, substitution of Spinning Reserve for Non-Spinning Reserve may cease even if the marginal Spinning Reserve Bid price is lower. To understand this phenomenon, assume that the next MW of Spinning Reserve increases the marginal Bid price of Spinning Reserve from $29 to $31, reduces the Non-Spinning Reserve procurement by 1 MW, and reduces the marginal Non-Spinning Bid price from $35 to $34. Assume that before substitution of the next MW, the volume of Spinning Reserve is 1,500 MW and that of Non-Spinning Reserve is 500 MW. The payment based on marginal price before substitution would be $29 * 1,500 + $35 * 500 = $61,000, and after substitution, $30 * 1,501 + $34 * 499 = $61,996. Therefore, although the 1 MW substitution reduces the Bid cost by $34 - $30 = $4, it increases the payment by $669. Thus, under the pre-MRTU market design, the payment minimizing Rational Buyer methodology would not perform the substitution. However, the MRTU Bid cost minimizing substitution methodology would perform this substitution. (Note that in this example, to simplify we have made the implicit assumption that opportunity cost of Energy associated with all AS Bids considered are all zero).

The CAISO's experience with the current payment minimizing Rational Buyer methodology is that there have been many situations of price inversion, *i.e.*, the Market Clearing Price for a lower quality service being higher than the Market Clearing Price for a higher quality service. This will not occur under the Bid-cost minimizing Rational Buyer adopted as part of MRTU.

2. Treatment of Ancillary Services Imports

Q. How, under MRTU, will AS procured from resources external to the CAISO Control Area?

A. Broadly speaking, except for AS provided by Dynamically Scheduled resources, AS procured over the interties from resources external to the CAISO Control Area is a slightly different product from AS supplied by internal generators, and therefore, there are differences in the manner in which it will be procured under MRTU:

- First, AS procured over the interties is an hourly product and will be procured only in the Day-Ahead Market and in HASP, where the Dispatch period is hourly. In comparison, AS from internal resources is an hourly product in the Day-Ahead Market, but is a 15-minute product in Real-Time. There will be no AS procurement from internal resources in HASP. Note that although AS Imports are hourly products, the import ASMPs in HASP are the simple average of the four 15-minute ASMPs computed simultaneously at the time of hourly pre-Dispatch. This is similar to the manner in which Energy LMPs are used to price Energy Imports in HASP (which are computed as the simple average of four 15-minute import Energy LMPs at the time of pre-Dispatch). In contrast, the ASMP for AS procured from internal suppliers in Real-Time are computed every 15 minutes.

- Second, because the Supply of AS from a Imports is vulnerable to intertie derates, the CAISO will limit the proportion of total AS procurement that can be supplied from Imports to 50 percent of its AS requirements, unlike internal resources where there is no procurement limit, aside from regional AS constraints. In addition, the import of AS on any given intertie may be limited to a percentage (e.g., 25%) of the CAISO's total AS requirements.
- Finally, AS that is procured from the interties has to compete with Energy Imports for capacity on the intertie to ensure delivery. If the intertie is congested in the import direction, then the Congestion price will be positive and the supplier will be charged for Congestion (regardless of whether or not the AS capacity is subsequently Dispatched to produce Energy in Real-Time).

Q. How will the Congestion price for AS Imports be computed under MRTU?

A. The Congestion price charged to AS Imports will be the shadow price of the intertie transmission constraint on which Energy and AS imports compete for transmission capacity. In the Day-Ahead Market, the shadow price will be computed hourly. In HASP, it will be computed as the average of the four 15-minute shadow prices determined simultaneously at the time of pre-Dispatch.

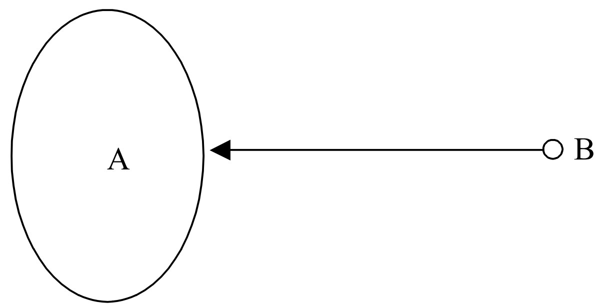
In computing the tie Congestion shadow prices, it is important to note that Ancillary Services will not provide counter-flows for either AS or Energy; thus, no netting will be allowed among Ancillary Services in the import and export directions, and obviously, only one of the intertie constraints may be binding in either direction at any given time.

Q. How will the competition between Energy and AS Imports impact the intertie scheduling point ASMPs and the intertie shadow price?

A. The competition between Energy and AS Imports for limited intertie capacity is determined by system-wide Bid Cost optimization. An example is helpful to demonstrate this concept:

Example VI.7 - Competition between Energy and AS on the interties:

Assume a single internal AS region (A), and a single intertie scheduling point (B) with an intertie transmission capacity of 100 MWs. Thus, the Expanded System Region in this example consists of Regions A and B. Assume only one service (e.g., Spinning Reserve) is procured, which is co-optimized with Energy. Also, to simplify the example further, assume vertical (price taker) Energy Demand (representing Load in the control area).



Assume that the Demand for Energy is 160 MW and that the AS requirement is 20 MW (similar to Example VI.1). To avoid relying on quantities of Import AS greater than 50% of the total procurement target, assume there is AS self-provision from internal resources of 10 MW. This assumption is used so that the zonal AS constraints are not binding and we consider only the interplay between AS and Energy Imports.

Assume that within the control area there is abundant Energy Bid in at $35/MWh, and abundant AS Bid in at $8/MWh. Also assume that there is more than 100 MW of Import Energy Bid in at $30/MWh, 4 MW of Import AS Bid (from importer I) at $1/MW/h and 20 MW of import AS Bid (from importer J) at $2/MW/h. The Import Energy Bids are from different importers than I and J.

Under this scenario, the least cost solution to satisfy the Load and AS requirements, subject to the 100 MW import limit on the sum of AS and Energy

Imports, is to procure 4 MW of AS from importer I, 6 MW of AS from importer J, no AS from resources in the control area (except the 10 MW self-provision), and 90 MW of Energy from Imports. The remaining 70 MW of Energy needed would be purchased from internal resources. The resulting Energy, AS, and Congestion prices are as follows:

- The Import scheduling point has its own Energy LMP of $30/MWh (representing the cost of meeting an incremental MW of Energy Demand at that location). Within the control area, Energy LMPs are all $35/MWh (assuming no internal Control Area Congestion and losses).
- To compute the ASMPs, note that the CAISO's AS Demand is always specified for the Control Area. The ASMP for all nodes in the Expanded System Region (including the Control Area and Import scheduling point in this example) is $7/MW/h. This is the case because an additional 1 MW of AS Demand would result in procuring 1 MW more AS from importer J at the cost of $2 plus the displacement of 1 MW of cheaper Import Energy by more expensive internal Control Area Energy (due to the Import constraint of 100 MW), with a net Energy Bid cost increase of $35 - $30 = $5, for a total cost of $2 + $5 = $7. Thus although there is Congestion on the intertie, the ASMPs are the same at the intertie and in the Control Area.

- The Congestion price on the intertie is the shadow price of the Import transmission constraint, which is $5/MWh. To understand this, let us see what happens if the intertie capacity is increased by 1 MW. This would allow displacing 1 MW of internal Energy with 1 MW of Import Energy for a net cost reduction of $5 (and no change in AS procurement). In other words, the Congestion shadow price reflects the difference in Energy prices across the intertie, but does not lead to a price difference between the ASMPs across the intertie.

The following table summarizes the Bids and resulting Energy and AS rewards in this example:

Resource	Capacity (MW)	Energy Bid ($/MWh)	AS Bid ($/MW/h)	Energy Award (MW)	AS Award or self provision (MW)	LMP ($/MWh)	ASMP ($/MW/h)
Resources in A	>160	$35	$8	70	10 (self provided)	$35	$7
Importer I	4	>$35	$1	0	4	$30	$7
Importer J	20	>$35	$2	0	6	$30	$7
Other Importers	>100	$30	No AS Bid	90	0	$30	$7

Note that importers I and J will both get paid the ASMP of $7/MW/h for their AS imports, but will be charged $5/MW/h for Congestion. Neither, however, would end up being paid less than their accepted AS Bid price. In fact, after paying for

Congestion, importer I ends up with a net of \$7 - \$5 = \$2/MW/h, which is \$1/MW/h above its AS Bid of \$1/MW/h.

Q. You mentioned earlier that under MRTU, the import of AS on each intertie could be limited, e.g, to 25%, of CAISO's total AS requirements. In the previous example you did not include this limitation. What happens to the prices in that example if this limit is enforced?

A. In the previous example, no explicit limit was enforced on the amount of AS Imports in order to simplify the illustration of competition between Energy and AS for the use of scarce Import transmission. The level of self-provision within region A (50%) was assumed to satisfy the limit on the total amount of AS from Imports (50%). In the following example we will assume no self-provision of AS, enforce the presumed 25% AS limit on the single tie explicitly, and observe the interplay between transmission constraints and AS zonal limits.

Example VI.8:

This example uses the same assumptions as used in Example VI.7, but with no AS self-provision, and with a limit of 25% (5 MW AS) on the inertie and a lower bound of 50% (10 MW AS) for internal control area AS procurement. The latter is obviously not a binding limit, and the former makes the Import node its own AS region. Thus, the Expanded System Region in this example now includes two AS sub-regions, designated A and B. Designating the AS procurements in regions A and B as RA and RB (with RB consisting of AS imports of RI and RJ from the two AS importers), and the Energy procurements as EA and EB, the following constraints must be adhered to:

RA + RB = 20 MW

RB <= 5 MW

RA >= 10 MW

RB + EB <= 100 MW

EB + EA = 160 MW

RB = RI + RJ

Using the Bid prices from Example VI.7, the least cost solution is as follows:

RI = 4 MW; RJ = 1 MW, RA = 15 MW, EA = 65 MW, and EB= 95 MW.

The resulting RASSPs are: -$1/MW/h for AS region B, $0/MWh for AS region A, and $8/MW/h for the Extended System Region. To understand these results, note that:

- An increase of 1 MW in the Import AS limit would allow the use of 1 more MW AS from importer J at $2, displacing 1 MW AS at $8 from A for a net AS cost reduction of $6. However, this would use one MW of the intertie capacity for AS, displacing 1 MW of cheaper Import Energy ($30) with the more expensive Energy ($35) from resources in A, with a resulting Energy cost increase of $5.

The net effect is a cost reduction of $1 for the combined AS and Energy procurement. Therefore, the RASSP for Region B is -$1/MW/h.

- Changing the 10 MW limit on Region A with 1 MW in either direction would have no impact on the solution. Thus the RASSP of Region A is $0.
- Increasing the total (Expanded System region) AS requirement by 1 MW would require 1 more MW of AS at the cost of $8. So the RASSP of the Expanded System Region is $8/MW/h.

It thus follows that the ASMP at B is $8 - $1 = $7/MWh and at A is $8 + $0 = $8/MWh. The LMPs are $35/MWh at A and $30/MWh at B, and the intertie shadow price is $5/MWh.

The following table summarizes the Bids and AS and Energy awards in this example:

Resource	Capacity (MW)	Energy Bid ($/MWh)	AS Bid ($/MW/h)	Energy Award (MW)	AS Award or self provision (MW)	LMP ($/MWh)	ASMP ($/MW/h)
Resources in A	>160	$35	$8	65	15	$35	$8
Importer I	4	>$35	$1	0	4	$30	$7
Importer J	20	>$35	$2	0	1	$30	$7
Other Importers	>100	$30	No AS Bid	95	0	$30	$7

Again, the importers I and J will both be paid the ASMP of $7/MW/h for their AS Imports, but will be charged $5/MW/h for Congestion. Neither would be paid less than their accepted AS Bid prices. In fact, after paying for Congestion, importer I ends up with a net of $7 - $5 = $2/MW/h, which is $1/MW/h above its AS Bid of $1/MW/h.

Q. What does the CAISO do with the Congestion payments it receives from AS importers?

A. Because the use of intertie capacity for AS reduces the capacity available for Energy Imports, in order to ensure revenue adequacy and to recover the cost of CRR payments on CRRs across congested interties, Congestion payments for AS Imports in the Day-Ahead Market are included (along with Congestion revenues collected based on Congestion component of the Energy LMPs) to pay CRR holders (with any excess credited to the CRR Balancing Account).

Congestion charges collected in HASP from AS Imports (and in Real-Time from dynamically scheduled intertie generating resources) are treated similarly to the Congestion revenues collected based on the Congestion component of HASP/Real-Time Energy LMPs. In other words, they are credited to the "Real-Time Congestion Offset." Again, this account is used to reimburse the ETC/TOR holders for their Real-Time Congestion charges, with any excess allocated to Metered Demand excluding ETC and TOR holders.

B. Ancillary Services Procurement in the IFM

Q. How much of its AS requirements will the CAISO target to procure in the Day-Ahead timeframe under MRTU as compared to its pre-existing market design?

A. Initially, under the current (pre-MRTU) market design, the CAISO's policy was to procure AS in the Day-Ahead Market based on the amount of Demand that cleared the Day-Ahead Market. Later, with the implementation of the Rational Buyer program, the CAISO set its AS target based on its Demand forecast, but would use an extension of the "Rational Buyer" concept to procure less than 100% of that requirement in the Day-Ahead market, by deferring a small percentage of its target to the Hour-Ahead Market if doing so would substantially reduce the AS Market Clearing Price.

Under MRTU, the CAISO will attempt to procure 100% of its AS requirements (established based on its Demand forecast) in the Day-Ahead Market.

Q. What will CAISO do if the amount of capacity Bid into the Day-Ahead market is not sufficient to meet both the Day-Ahead Demand for Energy and the AS requirements?

A. In the Day-Ahead timeframe, the ISO will place a higher priority on meeting its AS procurement target, as opposed to serving the Energy Demand. Therefore, if the amount of capacity Bid into the Day-Ahead Market is not sufficient to meet both Energy and AS requirements, then the CAISO will procure AS to satisfy its AS procurement target, and obtain the additional Energy necessary to satisfy Demand in HASP/Real-Time. It should be noted, however, that with Resource Adequacy (RA) and the RA-MOO requirement, the probability that the CAISO will run short of Bid-in Supply in the Day-Ahead Market is expected to be small. However, with the bulk of the RA obligation covered by liquidated damages contracts as of the start of the MRTU markets, this possibility should not be dismissed outright.

Q. What will the CAISO do if the Supply capacity Bid into the Day-Ahead Market is sufficient to meet both the Day-Ahead Energy Demand and AS requirements, but the Supply of capacity used for AS self-provision and capacity offered as AS Bids is insufficient to meet the ISO's AS requirements?

A. In such cases, CAISO will have no choice but to procure all AS that is Bid into the IFM, and procure the remainder in HASP/Real-Time.

Q. Will the CAISO use the RUC process to procure AS?

A. No.

C. Ancillary Services Procurement in HASP and Real-Time

Q. Will resources that Bid Energy into the HASP/Real-Time Markets be obligated to offer AS in HASP/Real-time?

A. Yes. Any internal resource that submits an Energy Bid in the HASP/Real-Time Market can be called on to provide both Real-Time Imbalance Energy and Real-Time AS. A resource can submit an AS Bid in addition to its Energy Bid. If it does not, however, a $0 AS Bid price will be assumed regardless of whether or not the Energy Bid in is from RA capacity. Of course, because non-RA resources are under no obligation to submit Real-Time Energy Bids, those resources will not be considered for AS if they elect not to participate in the Real-Time Energy Market.

Q. Please explain the reasons why the CAISO might need to procure Ancillary Services in the HASP and Real-Time, and how it would, if necessary, do so.

A. As I discussed earlier, the CAISO may, after the Day-Ahead IFM AS procurement process, need to procure additional AS to meet its AS procurement requirements because of AS Bid insufficiency in the IFM. In addition, there are several other potential reasons that the CAISO may need to purchase additional AS in HASP/Real-Time. These include changes in the CAISO's Load forecast after the close of the Day-Ahead Market, forced outages of resources that had planned to self-provide AS or sold AS in the Day-Ahead Market, or Real-Time

Energy Dispatch from Day-Ahead AS capacity that has not submitted a "Contingency Only" flag.

If necessary, the CAISO will procure its additional AS requirements from: (a) System Resources (Imports) in the HASP, and (b) generation internal to the CAISO Control Area in the Real-Time Market.

SCs will submit AS Bids for the HASP/Real-Time Market at 75 minutes before the operating hour (T-75). After Bid submission at T-75, the Real-Time pre-Dispatch ("RTPD") software performs the first RTPD run (HASP Dispatch) at T-67.5. In this run, the CAISO will procure imported hourly AS from the interties. Although this run will not procure AS from internal resources, it will take into account the AS that could be procured from such resources economically. This is similar to the process for the pre-Dispatching of Energy on the ties, where the CAISO will consider not only the intertie Energy Bids, but also the Energy Bids from internal resources. In fact, Energy and AS from both the interties and internal resources will be co-optimized in HASP, although only the intertie hourly schedules produced by HASP will be binding for the whole operating hour.

AS that the CAISO will obtain in the HASP/Real-Time timeframe from internal resources will be procured in 15 minute time increments by the RTPD process. The RTPD runs automatically every 15 min, at the middle of each quarter of each hour, *i.e.*, at 7½ min, 22½ min, 37½ min, and 52½ min into each hour. The AS awards published for the first 15 min interval of the RTPD time horizon are binding, while the remainder are advisory.

D. <u>Ancillary Services Settlements</u>

Q. How are the resources selected to provide AS in IFM paid?

A. Resources whose AS Bids are selected in the IFM are paid the relevant ASMPs. Again, please note that this does not apply to Self-Provided AS. Such capacity is not paid by the CAISO, but instead counts against the overall AS obligation of the relevant Scheduling Coordinator, as I explained previously.

Q. Are there any charges imposed on AS suppliers in IFM?

A. As stated earlier, Import AS Bids that are selected in the IFM pay the relevant intertie Congestion charge, if any.

Q. How are the resources selected to provide AS in HASP paid?

A. Only AS from hourly Imports are settled based on HASP AS prices. As I explained earlier in conjunction with the HASP clearing of Energy Bids, HASP uses a 15-minute Demand forecast for the operating hour, and produces four 15-minute prices for both Energy (LMPs) and AS (ASMPs) simultaneously. The simple average of the four 15-minute ASMPs at each intertie scheduling point is the hourly ASMP, and this price is what AS from hourly Imports are paid in HASP.

Q. Are there any charges imposed on AS suppliers in HASP?

A. As stated earlier, suppliers of AS over the interties are charged for Congestion if the intertie is congested. The Congestion price charged in HASP will be the simple average of the four 15-minute intertie shadow prices, computed simultaneously in the course of the HASP Energy-AS co-optimization process.

Q. How are the resources awarded AS in Real-Time paid?

A. Supplier of AS from internal resources as well as dynamically scheduled physical external resources that are selected to provide AS in Real-Time are paid the relevant 15-minute ASMP at the resource location multiplied by the amount of AS capacity (MW), multiplied by 0.25 (a quarter of an hour) for each 15 minute interval.

Q. Are there any charges imposed on AS suppliers in Real-Time?

A. Because dynamically scheduled intertie resources must compete with other external resources for transmission capacity, these resources must pay Congestion costs, if any, which are computed as 0.25 multiplied by the relevant 15-minute intertie congestion shadow price in each 15 minute interval. Suppliers of AS from internal resources do not compete for internal transmission capacity with Energy, however, and therefore, are not subject to these charges.

Q. If a supplier is awarded AS in the Day-Ahead IFM, is this a binding constraint or can the supplier buy that capacity back in HASP/Real-Time?

A. Under MRTU, suppliers that are awarded AS in the Day-Ahead Market will not be permitted to buy back that capacity in HASP/Real-Time for economic reasons. This is consistent with the fact that, as I explained earlier, under MRTU, the CAISO will no longer use price discrimination to defer AS procurement from the Day-Ahead timeframe to HASP/Real-time.

However, a supplier is permitted, in the HASP/Real-Time timeframe, to substitute a different resource for the AS awarded in the Day-Ahead Market, if the resource selected in the IFM suffers a forced outage or derate after the close of the Day-Ahead Market. In such an instance, the SC for the resource will be required to submit an outage notification to the ISO indicating that the original resource is not available. The SC can then self-provide another resource in HASP/Real-Time to make up for the AS that will not be available from the resource selected in the IFM. However, the capacity offered in HASP as self-provided AS may or may not be accepted by the ISO, depending on the HASP AS requirement and how the HASP optimization decides to meet that requirement. If the self-provided capacity is accepted, the exchange will not necessarily be at a net zero dollar settlement. The unavailable Day-Ahead AS capacity will lose the Day-Ahead ASMP that it was paid, whereas the HASP/Real-time self provided capacity will be settled at the relevant AS "user rate", as is the case with all self-provided AS

Q. What are AS suppliers paid when the awarded AS capacity is Dispatched by the CAISO as Energy?

A. If CAISO Dispatches Energy from AS capacity, and the supplier delivers the Energy, the supplier retains the payment for the AS capacity, and is also paid separately for the instructed Energy at the relevant (resource specific) Energy LMP.

E. <u>Ancillary Services No Pay</u>

Q. Will AS payments be rescinded under MRTU if the relevant resource does not perform as committed?

A. Yes. All AS award payments will be made subject to performance. AS "No Pay" charges will apply under the following conditions:

1) The AS capacity is not *dispatchable*, totally or partially, due to a forced outage, derate, or other limitations (such as available ramp rate capability). The No Pay capacity, *i.e.*, the amount of capacity subject to the No Pay charge in such a case is the undispatchable portion of the AS capacity.

2) The otherwise dispatchable AS capacity is partially or totally *unavailable* due to an uninstructed deviation by the resource. The No Pay capacity, *i.e.*, the amount of capacity subject to the No Pay charge, in such a case is the unavailable portion of the AS capacity.

3) The otherwise dispatchable and available AS capacity does not perform when called upon to produce Energy. If the resource does not deliver at least 90% of the Instructed Energy Dispatched from the AS capacity, it is subject to *undelivered* AS No Pay for all of the remaining AS capacity of the resource (not just the instructed but undelivered portion). For example, assume the AS capacity sold from a fast response unit to the CAISO is 60 MW. If the AS capacity is fully available, it should be able to produce 10 MWh during each 10 minute interval (60 MWh for the hour). Assume the resource is instructed to produce 5 MWh in a 10 minute interval, but the metered quantity shows only 4 MWh (80% of the instructed quantity). In this case the resource is assumed to have had only 24 MW of capacity available (since that is the capacity able to produce 4 MWh in 10 minutes). It thus has the remaining 60 - 24 = 36 MW subject to No Pay for this settlement interval. In other words, the No Pay capacity for this settlement interval is 36 MW. The No Pay charge for this interval is thus the No Pay rate for the resource times 36 * (1/6).

The AS capacity subject to No Pay is computed per settlement interval (10 minutes). An hourly equivalent No Pay capacity is then computed for each service for each applicable resource as the simple average of the six settlement interval No Pay capacities for the operating hour.

Q. If Import AS suppliers do not perform and are therefore subject to AS No Pay, will they be reimbursed for the Congestion charges that they paid for their AS Imports?

A. No. This is the case because such resources have already "used" the applicable amount of intertie capacity, regardless of whether or not they actually perform when called upon. Stated another way, that intertie capacity cannot be reallocated to other resources, and therefore, it is appropriate that the AS Import supplier pay the applicable Congestion charges, regardless of whether it is available to perform when called or not.

Q. What will AS suppliers be charged when they are subject to AS No Pay?

A. AS suppliers subject to AS No Pay charges will pay the AS No Pay rate per MW of capacity subject to No Pay. The AS No Pay rate is service and resource specific, *i.e.*, a separate No Pay rate is computed for Regulation Down, Regulation Up, Spinning Reserves, and Non-Spinning Reserves for each resource that was awarded or self-provided that service. For a resource subject to No Pay, it will be computed as follows:

1) All payments made to the resource for the service in question that are awarded in IFM, HASP, and Real-Time for the operating hour in question are added together (ignoring any Congestion charges that may apply if the resource is an Import resource).

2) Add all award quantities (MW) for resource for the service in question in IFM, HASP, and Real-time, as relevant (before considering any reduction due to No Pay). The award quantities are hourly for IFM and HASP, and the average of four 15-minute MW quantities in Real-Time if any.

3) Divide the payment computed in Step 1 by the quantity computed in Step 2 for the resource and service in question. This is the No Pay rate ($/MW/h) for that particular resource and service.

4) The rate computed in Step 3 is applied to the No Pay capacity (for the resource, service, and operating hour in question) only to the extent that the No Pay capacity does not exceed the total award quantity computed in Step 2).This amount is referred to as the Tier 1 No Pay Charge.

5) If the No Pay capacity (for the resource, service, and operating hour in question) exceeds the total award quantity computed in Step 2, the excess No Pay capacity (Tier 2) is used to reduce the

resource's amount of qualified self-provided AS for that service in the operating hour in question. To distinguish qualified self-provided AS resulting from the market-clearing processes from the remaining quantity of qualified self-provided AS after Tier 2 No Pay capacity reduction, the remaining quantity is referred to as the "effective qualified self provision" quantity.

F. Ancillary Services User Rate

Q. You stated that an SC with excess qualified self-provided AS will be paid the user rate for the relevant service. Would you please explain how these user rates will be computed?

A. Yes. The user rate for each service is a system-wide hourly rate for that service for the relevant operating hour, and will be computed as follows:

1) The total AS cost for the relevant service for the operating hour in question across all resources and across the IFM, HASP, and Real-Time Markets will be computed, taking into account any the costs of any higher quality service(s) used to substitute for the service in question, cost reduction due to Tier 1 No Pay charges (that I discussed in my response to the previous question), but not the Congestion payments made by importers of AS .

2) The net AS procurement quantity (MW/h) for the relevant service for the operating hour in question, across all resources and across

the IFM, HASP, and Real-Time Markets is computed, taking into account the quantities of any higher quality services used to substitute for the service in question, and any Tier 1 No Pay capacity reductions.

3) The user rate for the relevant service for the operating hour in question is the ratio of the results of Step 1 to the results of Step 2.

G. AS Cost Allocation

Q. How will the AS costs incurred by the CAISO allocated to Market Participants?

A. The basic principle for AS cost allocation is that the CAISO will use each SC's Metered Demand to compute each SC's obligation for each service and allocate the cost of each service at the same rate (user rate) for that service regardless of where (which AS Region) the SC's Load is located and how much of its Demand the SC scheduled in the Day-Ahead Market (versus its actual meter read).

Q. Can you provide a more detailed explanation of how AS costs will be allocated under MRTU?

A. Certainly. AS costs will be allocated in two tiers. The first tier of AS costs will be allocated as follows:

1) First, the hourly AS obligation of each SC for each service will be computed based on the SC's metered Load, and firm and non-firm

Energy Imports and Exports. I will explain in greater detail how each SC's obligation for the various Ancillary Services are calculated after I complete the response to this question.

2) Next any negative obligation (e.g., due to AS behind firm imports) will be adjusted as relevant to insure that credit for such negative obligations is given only to the extent they offset positive obligations net of qualified self provision. I will explain how the adjustment of negative AS obligation will be accomplished in the subsequent section.

3) Each SC's obligation for each service will be adjusted for the amount of effective qualified self-provided AS and any inter-SC trades of the service in question.

4) Finally, each SC's net obligation so computed for each service, will be charged (if positive) or paid (if negative) based on the user rate for the corresponding service.

Because the SCs' obligations are computed based on Metered Demand, but the CAISO's AS purchases are targeted based on CAISO Demand forecasts (net of qualified self provision), the Tier 1 allocation methodology that I just described could result in revenue non-neutrality. Therefore, additional payments or credits may be necessary to ensure revenue neutrality. This determination constitutes the second tier of AS allocation, and will be done as follows:

1) The AS neutrality adjustment for each service for the operating hour will be calculated as the difference between the costs (payments) and revenues (charges) system-wide for that service for that operating hour. For purposes of this calculation, the costs (payments) will be reduced by AS No Pay charges for the service, but not by Congestion revenues for AS Imports across the ties. The revenues (charges) are the net (positive or negative) of the Tier 1 charges (or payments) that I just described.

2) The AS neutrality adjustment for each service will be allocated to the SCs in proportion to their gross obligation for that service, if positive. For purposes of this determination, an SC's gross obligation for each service includes its obligation based on its metered Demand, with adjustments as relevant for net negative obligations. However, no reduction will be made on account of the SC's amount of effective qualified self-provided AS or the Inter-SC trade of AS.

Q. How will an SC's AS Obligation be established for each AS product for each hour?

A. The AS obligation of each SC for Regulation Up (or Regulation Down) in each hour will be established based on a per MWh Regulation Up percentage (or Regulation Down percentage) of that SC's Metered Load (Metered Demand excluding exports). The MW Regulation Up (or Regulation Down) obligation so computed would be non-negative. The SC's obligation is then augmented or reduced (and can go negative) based on its self-provision and Inter-SC trades of Regulation Up (or Regulation Down).

The MW Operating Reserve obligation of each SC in each hour is set at 7% of the SC's firm thermal Demand (Metered Load plus firm Exports minus firm Imports, all met by thermal generation) plus 5% of the SC's firm hydro Demand (Metered Load plus firm Exports minus firm Imports, all met by hydro generation), plus 100% of non-firm Imports. The MW Operating Reserve obligation so computed may be positive or negative depending on the relative volumes of firm and non-firm Imports and Exports in the SC's schedule. As discussed previously, negative Operating Reserve obligations are credited only to the extent that their sum, system-wide does, not exceed Positive Operating Reserve obligations system-wide less qualified self-provided Operating Reserves. The SC's Operating Reserve obligation (positive or negative) is then augmented or reduced based on its qualified self-provision and its Inter-SC trades of Operating Reserves.

H. Treatment of Ancillary Services Behind Firm Imports

Q. How are Ancillary Services behind firm Imports currently treated?

A. Under the CAISO's current (pre-MRTU) market design and based on existing WECC rules, firm Imports are backed by Operating Reserves (Spinning and Non-spinning reserves) from the sending Control Area. For example, an SC with a Load of 5,000 MW who meets part of that Load with 1,000 MW of firm Import will only be assessed Operating Reserves for 4,000 MW of its Load. Assume that the Operating Reserve requirements are computed as 6.5% of the SCs total Load (using a 5% hydro and 7% thermal mix). The SC's operating reserve obligation is thus, 6.5% * 4,000 = 260 MW/h (instead of 6.5% * 5,000 = 325 MW/h, if the SC had met all of its Load with resources internal to the CAISO Control Area).

Under the current market design, the CAISO procures AS sequentially after clearing the forward Congestion market. Therefore, the CAISO knows how many MWs of firm Imports have cleared the market, and reduces its Operating Reserves procurement target accordingly. For this reason, there are no adverse cost causation consequences to the CAISO not assessing Operating Reserves relating to firm Imports.

One issue with respect to the current design, however, is whether an SC should receive credit for the Operating Reserves behind its firm Import if the firm Import exceeds its Load. More generally, the question applies to firm Imports by SCs with no Load. One could argue that to the extent these firm Imports reduce the CAISO's Operating Reserve requirements, they should be compensated for the reduction in Operating Reserves that the CAISO needs to procure. However, this solution could lead to problematic results if applied indiscriminately. For example, an SC could schedule 1,000 MW of firm Imports and 1,000 MW of non-firm Exports, with a net zero impact in the forward market clearing process. It would then be eligible for a credit for 65 MW (6.5% * 1,000) of Operating Reserves for its firm Import. Thus the SC would be paid for 65 MW of Operating Reserves without providing any net interchange into the CAISO Control Area.

To avoid perverse scheduling incentives, when an SC without any Load imports firm power under the current market design, it is credited for the Operating Reserves supporting that Import if, and only if, that SC sells the AS to another SC with a positive Load obligation (through an inter-SC trade of AS). The traded AS is netted against the recipient SC's procurement (not its obligation). If the SC with no Load that imports firm Energy sells only the Energy and fails to sell the AS, it receives no credit of any kind.

Q. How will this functionality change under MRTU and why?

A. Under the MRTU design, an SC will receive a credit for Operating Reserves behind firm Imports even if the importing SC has no Load obligation and the SC does not engage in an Inter-SC trade of Energy or AS. However, it should be noted that the credit for these "negative Operating Reserves," even under MRTU, is limited to the amount that offsets positive obligations net of qualified self-provision. I will explain this limitation in greater detail after I complete the current response.

As opposed to Phase 1b, where balanced schedule requirements prevail and there is no Day-Ahead Market for Energy, under MRTU SCs can enter the Day-Ahead IFM in a net-short position, due to the fact that there is no balanced schedule requirement, and rely on the IFM to meet the balance of their Energy requirements. Conversely, generators can Bid into the IFM to Supply their aggregated net-short Energy positions. In-state generators that Bid into the Day-Ahead IFM will be Bidding in Energy unbacked by reserves, but firm Imports will be Bidding in Energy backed by reserves. Therefore, the ISO believes that it is reasonable to compensate Imports for the reduction in overall AS procurement that they allow. The limitation of credits for negative Operating Reserves to the amount usable by the CAISO to meet the CAISO's Operating Reserve requirements will ensure fairness, because it will prevent importers from being paid for services that are not useful to the CAISO Control Area.

Q. You mentioned that there will be a limitation, under MRTU, to the credit that SCs can receive for negative Operating Reserves? Can you explain this concept in greater detail?

A. Yes. In exceptional cases, it may happen that the net total quantity of Operating Reserve Obligations of all Scheduling Coordinators in a Trading Hour after accounting for qualified self provision is negative. In this case the net negative Operating Reserve Obligation is not usable by the CAISO, because AS self provision is qualified before IFM based on the CAISO's estimate of firm Imports. In such a case, the Negative Operating Reserve Obligations of all SCs with Negative Operating Reserve Obligations is reduced pro rata. This is accomplished by multiplying the Negative Operating Reserve Obligation of each SC by a factor called the Negative Operating Reserve Credit Adjustment Factor ("NOROCAF"). This factor is computed as the minimum of 1.00 or the ratio of (a) net total quantity of Operating Reserve Obligations of all Scheduling Coordinators with positive Operating Reserve Obligation net of qualified self-provision, and (b) the sum of Negative Operating Reserve Obligations of all SCs with Negative Operating Reserve Obligations before any self-provision.

Q. **Can you illustrate this by an example?**

A. Certainly.

Example VI. 9 – Negative Operating Reserves Obligation Credit Adjustment Factor ("NOROCAF"):

Assume the Operating Reserve requirement is 7% of the CAISO Load, and that firm Imports are backed by 7% Operating Reserve from the exporting Control Area. The ISO's forecasts for Load and Imports for a given hour are 40,000 MW and 8,000 MW respectively. So, the system-wide forecast of Operating Reserve Requirements is 7% * 40,000 – 7% * 8,000 = 2240 MW for the hour.

Assume there are three SCs, with the total quantity of 1,800 MW of qualified AS self-provision. The CAISO thus targets to procure 440 MW of Operating Reserves in the IFM. To simplify the case, assume the CAISO's forecasts are accurate and the actual Loads and net Imports are in fact 40,000 MW and 8,000 MW respectively in real time. Also assume there are only two SCs with the following Load and interchange quantities, and Operating Reserve self provision:

SC	Load (MW)	Firm Energy Import (MW)	Non-Firm Energy Export (MW)	Self Provided Operating Reserve (MW)
SC1	28,000	8,000	0	1,800
SC2	10,000	0	0	0
SC2	2,000	8,000	8,000	0
System	40,000	8,000		1,800

The Operating Reserve Obligations of the SCs are:

- SC1: (7% * 28,000 – 7% *8 ,000) – 1,800 = 1,400 – 1,800 = -400 MW
- SC2: 7% * 10,000 = 700 MW
- SC3: 7% * 2,000 – 7% * 8,000 = -420 MW

The net Operating Reserve obligation system-wide is thus –-400 + 700 - 420 = –120 MW, i.e., negative. The NOROCAF is therefore 300/420 = 71%. This factor applies to the negative Operating Reserve Obligation before any self provision or trade. Because SC1's obligation before self provision is (7% * 28,000 – 7% * 8,000) = 1,400 MW, *i.e.*, positive, it is not adjusted. This is also the case for SC2. However, SC3's negative obligation is adjusted, resulting in – 420 * 71% = -300 MW of negative Operating Reserve Obligation for SC3.

Note that in this example, the CAISO had already procured 440 MW of Operating Reserves based on its forecast and the quantity of self provided AS in the Day-Ahead IFM. Assume the user rate for this purchase is $20/MW/h. So, the SCs are charged and paid as follows based on their positive Operating Reserve Obligations before self provision or trade:

Tier 1 Cost Allocation:

SC1 Credit: $20 * (400) = ($8,000)

SC2 Charge: $20 * (700) = $14,000

SC3 Credit: $20 * (300) = ($6,000)

This results in revenue shortfall for the CAISO. The CAISO has a deficit of $20*440 = $8,800, which must be recovered through AS neutrality cost allocation to the SCs with positive obligation before any self provision or trade (gross obligation), *i.e.*, 1,400 MW for SC1 and 700 MW for SC2. Thus the Tier 2 rate is $8,800 / (1,400 + 700) = $4.19 per MW of Obligation

Tier 2 Cost allocation:

SC1 Charge: $4.19 * 1400 = $5,867

SC2 Charge: $4.19 * 700 = $2,933

SC3 is not allocated any Tier 2 cost because its AS Obligation (before self provision or trade) is negative.

In summary the net settlement amounts are:

SC1 Credit: $8,000 - $5,867 = $2,133

SC2 Charge: $14,000 + $2,933 = $16,933

SC3 Credit: $6,000

The sum is $8,800, and the CAISO is revenue neutral.

VII. RUC PRICING, PAYMENT AND COST ALLOCATION

A. <u>Pricing and Payment for RUC</u>

1. RUC Selection Process

Q. Please describe the RUC Bid selection process.

A. The RUC process commits resources as needed and designates capacity needed to meet the CAISO's Load forecast, while preserving accepted IFM Supply Schedules. It utilizes the Security Constrained Unit Commitment (SCUC) methodology to minimize the cost of necessary additional resources and capacity. The cost elements used in to establish RUC prices are Start-Up and Minimum Load Costs for units not already committed in IFM, along with submitted Availability Bids (RUC capacity Bids). Availability Bids in RUC are analogous to Energy Bids in the IFM.

Q. Can all resources participate in RUC?

A. No. A resource must first Bid into the Day-Ahead IFM to be considered in the RUC process.

Q. Does that mean that a resource under a Resource Adequacy contract would not have to Bid into the Day-Ahead IFM to be considered in RUC?

A. Only with respect to a limited set of RA resources (such as hydroelectric or PIRP resources) that are not subject to the Day-Ahead Must-Offer Obligation. Other RA resources are expected to participate in the IFM unless they experience a forced outage. If a resource under RA does not voluntarily Bid into the IFM, proxy Energy Bids will be inserted for it into the IFM to the extent of its capacity under RA contract.

Q. Can all resources participating in RUC submit Availability Bids?

A. No. Only non-RA resources (more specifically non-RA capacity), and capacity not pre-Dispatched as RMR, may submit non-zero RUC Availability Bids.

2. RUC Pricing

Q. How are the resources selected in RUC paid?

A. Resources selected in RUC will be made whole for their Start-Up and Minimum Load Costs net of market revenues. In addition, if eligible, they will receive an RUC Availability payment equal to the RUC LMP at their location multiplied by the amount of their RUC capacity award, which is the capacity selected in RUC above the Minimum Load of the unit if the unit is committed in RUC, or above its IFM schedule if the unit was already committed in the IFM.

Q. How is the RUC availability Market Clearing Price determined?

A. The nodal prices established based on RUC availability Bids in the SCUC process described above are RUC LMPs. The RUC LMPs are used to pay eligible resources whose RUC Availability Bids are selected by the CAISO.

Q. Which resources are eligible to receive RUC Availability payments?

A. Non-RA resources and resources not called under RMR for the specific operating hour are eligible to receive a RUC Availability payment if selected in RUC.

Q. Can RUC LMPs be repartitioned into system marginal cost, Congestion, and loss components, in the same manner as LMPs associated with the IFM, HASP and Real-Time markets?

A. Yes. But the components would not be used for settlement purposes in RUC.

Q. Are Constrained Output Generators ("COG") eligible to participate in RUC, and if so, how are they compensated?

A. COG resources are considered in RUC, but they cannot Bid nor receive RUC Availability payments. However, as with other resources, they are entitled to recover their Start-Up and Minimum Load Costs.

Q. Why are COG resources considered in RUC but not eligible to submit, set, or be paid RUC Availability?

A. The reason why COGs are included in RUC is because they are treated as flexible resources in IFM, but they are modeled along with their technical and inter-temporal constraints in HASP/Real-time. The only reason why they are treated as flexible in IFM is to preserve the relationship between marginal Congestion pricing and Energy pricing. The reason why they are fully modeled in RUC is because RUC is the prelude to HAPS/Real-Time, and COGs are fully modeled in the Real-Time market.

In IFM, the minimum Load (Pmin) of the COGs is set to 0 MW, and their inter-temporal constraints (minimum run times) are ignored. Their Energy Bid between 0 and Pmax is their minimum Load Bid cost divided by their Pmax. Since they can have only one Pmin cost for all hours of the day, their computed $/MWh Bid price between 0 and Pmax would be the same for all hours of the day.

If the COG resource is partially scheduled in IFM, the COG unit will be considered at full capacity in RUC, and will receive a Dispatch Instruction in HASP/Real-time. The COG unit can set the Energy price in Real-Time if the COG, assuming it was a flexible unit, would have been able to (treating set the price. However, if as flexible units they would have been Dispatched to 0 MW in real time, but they cannot shut down due to their known (modeled) technical constraints such as minimum run time, they will be instructed to go to Pmax without setting the Real-Time Energy price. In that case, they are eligible for Minimum Load Bid cost recovery.

In sum, after the Day-Ahead IFM, a COG unit is scheduled and compensated for its Minimum Load, which is by definition equal to its maximum Load, leaving no capacity eligible to receive a RUC availability payment.

Q. Are short start and long start units both eligible for RUC commitment cost compensation?

A. Yes, to the extent they are given RUC Awards. However, as mentioned earlier, only non-RA resources, and resources not called under RMR, are eligible to receive RUC Availability payments.

B. RUC COST ALLOCATION

Q. Are LAP RUC Availability prices allocated to Load in a manner similar to LAP Energy prices?

A. No. RUC costs are allocated based on RUC User rates, which in some ways are similar to, but in other ways different from the methodology for allocating Ancillary Services costs. The main difference is that the User rate for allocation of RUC costs includes both the RUC Availability payment and the RUC uplift payments (including uplifts for start up and minimum Load costs).

Additionally, RUC costs are allocated in two tiers. The first tier is a charge to Demand that fails to schedule in IFM at a rate that does not exceed the RUC User rate. Any remaining costs are allocated pro rata to Metered Demand.

I address this concept of RUC cost allocation in greater detail in the subsequent section on Bid Cost Recovery (Section IX).

VIII. <u>BID COST RECOVERY</u>

Q. What is the Bid Cost Recovery mechanism?

A. The Bid Cost Recovery ("BCR") mechanism is the process by which the CAISO ensures that SCs are able to recover the Start-Up and Minimum Load costs for resources that are committed by the CAISO, and not otherwise self-committed by an SC. The BCR mechanism also ensures that SCs are able to recover the costs of their accepted Energy Bids (above Minimum Load) that fail to set the price (due to temporal or other constraints such ramp rate limitation) and their accepted RUC Availability Bids for resources that are eligible to submit RUC Bids, and be paid RUC Availability, but fail to set the RUC price (due to temporal or other constraints such as ramp rate limitation) regardless of whether the resource was committed by the CAISO or self-committed by the SC. Such recovery is netted over a trading day and is net of market revenues received across the various CAISO markets. The BCR mechanism also provides an allocation methodology through which the resulting uplift costs are allocated for each CAISO market and Settlement Interval.

Q. Why does the CAISO intend to guarantee recovery of Start-Up and Minimum Load Costs for resources?

A. Under MRTU, generating units are allowed to submit three part Bids, including Start-Up, Minimum Load, and Energy. However, only the Energy Bid price can set the LMP. Although an inframarginal resource (*i.e.*, a resource whose Bid price is below the LMP) is not paid less than its Energy Bid price, there is no guarantee that the extra revenues it receives for its Energy (including Minimum Load Energy) at its LMP rate will cover its start-Up and Minimum Load costs. Therefore, in order for an SC to recover these costs, they must be paid through an uplift. In the absence of such an uplift ,the SC would have to internalize its start up and minimum Load cost in its Energy Bid, which would result in an inefficient market outcome.

Q. Why does the CAISO intend to guarantee recovery of Energy Bid prices for resources?

A. Energy Bids are selected in the Bid-cost minimization process with a view to the optimization time horizon. For example, in IFM the Bids are selected with a view to all hours of the day. A resource that has inter-temporal constraints may set the price in one interval, but not in another due to its ramp rate limitations. This is particularly prevalent in RTM where the unit is Dispatched on shorter time intervals (5 minutes) and its ramp rate may prevent it from reaching an otherwise optimal economic operating point in 5 minutes. For example, a $30/MWh Bid may be Dispatched in an interval where the LMP at its location is $31/MWh, but if the Energy requirement is lower in a subsequent interval, another unit may set the LMP at the resource's location at $27/MWh. If the unit cannot ramp down fast enough, it will be producing Energy that it had Bid in at $30/MWh, but will receive only $27/MWh in the second interval. It will thus have a net shortfall between the two intervals. Because the CAISO is issuing these Dispatch instructions, the unit should be eligible to recover its Bid cost.

Q. Which resources are eligible to receive BCR?

A. As stated above, BCR has three main components, Minimum Load cost, Start-Up Costs and Bid cost. BCR for Minimum Load and Start-Up Costs is limited to Generation Units, *i.e*., generators in the CAISO Control Area, Participating Load and resource-specific System Resources (*i.e*., System Resources that are unit-specific resources and are therefore able to submit three-part Bids that include Energy Bids, and non-zero values for Start-Up and Minimum Load Bids), but only during those hours that they are committed by the CAISO. BCR for the Bid Costs of accepted Bids (not including start up and minimum Load Bids) is available to all resources scheduled or Dispatched by the CAISO regardless of whether or not the resource was committed by CAISO, provided, however, that the resource performs according to CAISO instructions.

Q. Why does the CAISO propose to ensure recovery of Start-Up and Minimum Load costs for unit-specific System Resources?

A. Bids from unit-specific System Resources are Bids for Energy from actual physical capacity located outside of the CAISO Control Area that the CAISO is capable of committing and calling upon through a contractual relationship such as a Participating Generator Agreement or a Dynamic Scheduling Agreement. In contrast, Bids from non-unit-specific System Resources do not reflect Start-Up or Minimum Load Energy tied to specific physical resources, and may be simply an intertie schedule for exchange of Energy between two control areas. Start-Up and Minimum Load Costs for such resources are, therefore, not applicable.

Q. Why are resources not eligible for BCR if they are self-committed or if they are designated for self-provision of Ancillary Services?

A. Resources that are self-committed by Scheduling Coordinators are not eligible for BCR for their Minimum Load and Start-Up Costs, because their Start-Up Costs and Minimum Load Costs are considered to be $0. If they had instead submitted non-zero Start-Up and Minimum Load Bid prices, there would be a good chance the CAISO would not have committed them. By self committing they are displacing another resource that may have had a lower start up and minimum Load cost than theirs. If they submit a Self-Schedule or self provide AS, they are presumed to have self committed; this is because to deliver their self schedule, they must have an “on” status (i.e., committed). Despite the fact that these resources are not eligible for BCR for their Start-Up and Minimum Load costs, they are eligible for BCR with respect to their market Bids accepted by CAISO, provided that they follow CAISO’s Dispatch instructions. If they do not, they are presumed to be operating pursuant to a bilateral contract through which the resource is likely to be receiving compensation not only for its uninstructed Energy, but also for its Start-Up and Minimum Load Costs.

Q. How does the CAISO determine the Bid costs that are recovered through the BCR mechanism?

A. For each time period during which a resource is committed by the CAISO, the CAISO calculates the total Bid costs to be recovered in each Trading Hour for each resource. Such Bid costs include : (1) Start-Up Costs, (2) Minimum Load Costs, (3) Energy costs, (4) AS costs and (5) RUC costs. Moreover, for each hour during the Self Commitment period where the resource follows CAISO Dispatch instructions, the CAISO calculates the Energy costs, AS Bid costs and RUC Bid cost. I explained above what Start-Up Costs and Minimum Load Costs are. The Energy cost is the integral of the Energy Bid cost curve (as mitigated in the CAISO market power mitigation runs) that has been scheduled or Dispatched by the CAISO. The Ancillary Services costs are the product of the awarded quantity of Ancillary Service, reduced by any Ancillary Services no-pay capacity, multiplied by the applicable ASMP. RUC costs are the product of the awarded RUC Capacity, reduced by any no-pay Ancillary Services capacity, and the applicable RUC Price. I will explain below, in detail, how these various costs and revenues will be determined in each of the CAISO's MRTU markets.

Q. Are the Bids submitted by Scheduling Coordinators for Start-Up and Minimum Load costs cost-based or market-based?

A. The SCs have two options for the Start-Up and Minimum Load Costs: (a) Bid-based, but fixed for 6 months; (b) cost-based, but adjustable based on fuel prices.

Whether they are Bid in or based on proxy cost data, however, each trading day's Start-Up and Minimum Load Costs for each unit remain the same throughout the given day.

A. Determination of CAISO Commitment Periods

Q. You mentioned earlier that resources are only eligible to receive BCR payments for their start up and minimum Load costs during those time periods in which they are committed by the CAISO. Can you explain this concept in greater detail?

A. Yes. But first, I believe it would be helpful to explain the basic concept of a Commitment Period" A Commitment Period consists of the consecutive time periods in a Trading Day during which a unit is "on," that is, the unit is online, synchronized with the grid, and available for Dispatch. In contrast, a unit is considered "off" when it is offline or in the process of starting up or shutting down. The time periods that comprise a Commitment Period is dependent on the market that a unit is participating in. The time period in the Day-Ahead Market is a Trading Hour, while the time period in the Real-Time Market is a 5-minute Dispatch Interval.

For purposes of determining whether a resource is eligible to receive a BCR payment, there are two distinct sub-types of Commitment Periods. The first is a "Self-Commitment Period." This is the portion of a Commitment Period during which a unit is operating pursuant to an Energy Self-Schedule or an AS Self-Provision, except for Non-Spinning Reserves that are self-provided by a Fast Start Unit. A Self-Commitment Period may include time periods when a unit is not operating pursuant to an Energy Self-Schedule or an AS Self-Provision if it is determined by inference that the unit must be on due to the unit's ramping up and ramping down constraints. Resources are not eligible to receive BCR payments for Start-p and Minimum Load Costs during Self-Commitment Periods.

The other type of Commitment Period is a "CAISO Commitment Period." This is the portion of a Commitment Period that is not a Self-Commitment Period. Resources are eligible to receive BCR payments for actual Start Up, Minimum Load and Energy pursuant to CAISO instructions that they provide during CAISO Commitment Periods.

Commitment Periods can also be explained in terms of the three different markets. So, there are "IFM Commitment Periods," "RUC Commitment Periods," and "RTM Commitment Periods." These are simply the Commitment Periods during which a unit is operating in the IFM, RUC, or Real-Time Markets, respectively.

Finally, a Commitment Periods can be explained both in terms of the relevant market and commitment type. For instance, an "IFM Self-Commitment Period" would be a Commitment Period in which a unit was participating in the IFM pursuant to a Self-Schedule or Self-Providing AS.

Q. How does the CAISO determine whether an IFM Commitment Period is a Self-Commitment Period or a CAISO Commitment Period?

A. As I noted above, a CAISO Commitment Period for a resource is any Commitment Period for the resource that is not a Self-Commitment Period for that resource. With respect to the IFM, the CAISO defines an IFM Self-Commitment Period to include all consecutive Trading Hours in which the resource has submitted a Self-Schedule for Energy or has indicated that it will be self-providing AS, except if the self-provision is for Non-Spinning Reserves by a Fast Start Unit. A Self-Commitment period for a resource may not be less than the minimum run time of the resource (rounded up to the next hour). Consequently, if a resource first self-commits in hours *h,* the Self Commitment Period will be extended to hour h+MUT-1, where MUT is the minimum run time of the resource. Any two non-consecutive IFM Self-Commitment Periods for a unit may not be separated by less than the minimum down time of the resource, i.e., the time it takes for that a resource to ramp down, and start up to its minimum Load again. Consequently, if a resource self-commits in hours *h* and *h* plus *n*, where *n* is greater than 1 (i.e., the hours are not consecutive), the CAISO will extend the IFM Self-Commitment Period of the resource to the hours in between those two hours if *n* is less than the minimum down time (MDT) for the resource plus 1 Finally, in any given Trading Day, the number of IFM Self-Commitment Periods for a given resource may not exceed the relevant minimum number of daily starts (MDS) for that resource. If the first IFM Commitment Period is the continuation of an IFM or RUC Commitment Period from the previous Trading Day, then the number of IFM Self-Commitment Periods for the given Trading Day for the specific resource is increased may not exceed MDS plus 1 hour. If the number of IFM Self Commitment Periods for the resource do exceed this limit, then the Self Commitment Periods with the smallest time separation will be combined along with the hours in between as part of the IFM Self Commitment Period for the resource.

Q. How will the CAISO determine whether a RUC Commitment Period is a Self-Commitment Period or a CAISO Commitment Period?

A. The CAISO does not allow RUC self provision. Therefore, there is no need to identify a RUC Self-Commitment Period. Incidentally, a RUC Commitment Period that is contiguous with or overlaps an IFM Commitment Period automatically includes the IFM Commitment Period. However, since the BCR rules must be applied in sequence, this does not change the outcome of the BCR computations for the resource for the IFM Commitment Period (that is now part of the RUC Commitment Period for RUC BCR computations). The BCR rules are designed such that when applied in sequence, the resource is not double paid for start up cost or minimum Load, but will have Bid cost recovery for its RUC capacity over the entire RUC Commitment Period.

Q. How will the CAISO determine whether an RTM Commitment Period is a Self-Commitment Period or a CAISO Commitment Period?

A. Just like for IFM Commitment Periods, the CAISO will consider RTM CAISO Commitment Periods to include any Trading Hour in an RTM Commitment Period which is not part of a RTM Self-Commitment Period. An RTM Self-Commitment Period includes all consecutive Dispatch Intervals for which the relevant resource has submitted a Self-Schedule for Energy or has indicated that it will be self-providing Ancillary Services in the Real-Time Market, except if the self-provision is for Non-Spinning Reserves by a Fast Start Unit. In addition, a RTM Self-Commitment Period will not include any Dispatch interval that was determined to be part of a RUC Commitment Period, which is described below.

An RTM Self-Commitment Period for a resource may not be less than the relevant minimum up time (MUT) for the resource, rounded up to the next 15-min commitment Interval when considered jointly with any adjacent IFM Self Commitment period. Consequently, if a resource self-commits at time h, the self-commitment will be extended to Commitment Interval h + MUT, unless an IFM or RUC Commitment Period exits starting after hour h, in which case the self-commitment will be extended to Commitment Interval h + min (MUT, t).

An RTM Self-Commitment Period for a resource when considered jointly with any adjacent IFM Self Commitment period may also not be separated from a RUC Commitment Period by less than the relevant minimum down time for the resource, rounded up to the next 15-min Commitment Interval.

Consequently, if a resource self-commits at time T_1 and has been awarded a RUC schedule at T_2, which is before T_1, the RTM self-commitment will be extended to the commitment intervals in between T_1 and T_2, if T_1 minus T_2 is less than the minimum down time for the resource. Finally, the number of RTM Self-Commitment Periods, when considered jointly with any adjacent IFM Self Commitment period, for a unit within a Trading Day may also not exceed the relevant maximum daily Start-Ups (MDS) for a given resource. If the first RTM Commitment Periods is the continuation of a RTM Commitment Period from the previous Trading Day, then the maximum daily Start-Ups will be increased by 1. Consequently, if a resource self-commits at time T_1 and has been awarded a RUC Schedule at time T_2, which is later than T_1, the RTM Self-Commitment Period will be extended to the commitment intervals in between T_1 and T_2, if an additional RTM Start-Up at T_1 would violate the maximum daily Start-Up constraint.

Q. How does CAISO determine what constitutes a RUC Commitment Period?

A RUC Commitment Period is any Trading Hour during which a resource is committed by the RUC process. The RUC software may not de-commit resources that were committed in the IFM. Therefore, a RUC Commitment Period always includes an overlapping IFM Commitment Period. However, a RUC Commitment Period may start earlier and/or may end later than an overlapping IFM Commitment Period if a resource is issued an earlier Start-Up and/or later Shut-Down in RUC than it is in the IFM. A RUC Commitment Period may also not contain an IFM Commitment Period if the unit is not scheduled by the IFM within that period.

Because there is no self-commitment in RUC, all RUC Commitment Periods are, by definition, also CAISO Commitment Periods.

B. <u>Calculation of Unrecovered Bid Costs</u>

Q. Please explain, in detail, how the unrecovered Bid cost of a resource is determined?

A. I will explain in greater detail below how the CAISO determines the component Bid costs and market revenues relating to each of the three markets. In summary, however, for each CAISO market process, *i.e.* the IFM, RUC and the Real-Time Market, the CAISO will calculate the total Bid costs for each resource , for each Settlement Interval in each CAISO Commitment Period, and the total Bid costs excluding Start Up and Minimum Load Costs for each Settlement Interval in a Self Commitment Period . The CAISO will then net from these amounts the market revenues derived by the resource from all of the CAISO Markets in each Settlement Interval. If the difference between the Bid costs and the market revenues is positive, then that amount represents a shortfall for the specific CAISO Market. If the difference is negative, then that amount represents a surplus relating to the specific CAISO Market. The CAISO will then nets the resource's shortfalls and surpluses over each Trading Day. If the resulting amount is positive, then the unit is entitled to a BCR payment in this amount for that Trading Day.

Q. What is the justification for netting of shortfalls and surpluses over each Trading Day?

A. Resource commitment is a decision involving the consideration of costs and benefits over the commitment horizon. The IFM and RUC market-clearing processes are both daily commitment decisions. Therefore, it is logical that revenues made in an hour from these markets should offset costs incurred in a different hour relating to these markets during the course of the same Trading Day. Regarding RTM, the processes comprising RTM, start with 5 hour look-ahead in the Short Term Unit Commitment (STUC), and are time phased in Real-Time Unit Commitment (RTUC), and Real-time Economic Dispatch (RTED). The decisions in each process feed into the next. For example, a unit with a minimum start up and run time of 4 hours committed in STUC reflects a commitment decision that was made taking into account both the Energy Bid price sand the start up and minimum costs. In all of these market processes, the constraints that result in prices in some intervals being insufficient for certain resources to recover its their Bid Costs ultimately results in a less economic solution overall than where the constraint had not been present. However, a resource that might be constrained in some intervals will be provided an opportunity to benefit from those solutions that increase the amount of infra-marginal Energy Dispatched and settled in other intervals

Therefore, it is appropriate that if a resource is being compensated via an uplift payment when the resource is extra-marginal (*i.e.* not recovering its costs), that the resource internalize such payments before spreading such costs to the rest of the market. Since the effects of a constrained resource has impacts beyond one interval or one hour, and the fact that the optimization horizon is continuously shifting from one hour to the next, I believe that it is reasonable to adopt a 24-hour netting period for purposes of calculating BCR. Also, this daily compensation approach is consistent with other ISO with regards to Bid cost recovery.

1. Calculation of Bid Costs and Market Revenues in the IFM

Q. Can you please explain more specifically how the CAISO will determine the Bid cost associated with a unit participating in the IFM?

A. For each Settlement Interval in a CAISO IFM Commitment Period, in an IFM Commitment Period, the Bid cost associated with a unit participating in the IFM will be calculated as the algebraic sum of the qualified IFM Start-Up Costs, the qualified Minimum Load Costs, the IFM pump shut-down costs, the IFM Energy Bid costs and the IFM Ancillary Services Bid Cost. For each Settlement Interval in a Self Commitment Period, in an IFM Commitment Period, the Bid cost associated with a unit participating in the IFM will be calculated as the algebraic sum of the IFM Energy Bid costs and the IFM Ancillary Services Bid Cost.

Q. You mentioned qualified IFM Start-Up Costs. Please explain what you mean by qualified IFM Start-Up Costs, and the rules that the CAISO has developed to implement to determine which IFM Start-Up Costs will be considered qualified IFM Start-Up Costs.

A. IFM Start-Up Costs for a given IFM Commitment Period are the Start-Up Costs incurred by the Scheduling Coordinator for the relevant resource participating in the IFM. The CAISO applies a series of rules sequentially to determine whether the Start-Up Costs incurred by a resource during IFM Commitment Periods qualify for BCR. That is, the CAISO applies the first rule, and if the Start-Up costs are not set to zero or otherwise modified, and therefore remain qualified, the

CAISO applies the second rule and if the Start-Up costs remain qualified for that Commitment Period it applies the next rule, and so on.

Q. What are the sequential rules that the CAISO applies to determine whether IFM Start-Up Costs are qualified?

A. First, if there is an IFM Self-Commitment Period within the IFM Commitment Period, then the Start-Up Costs for that IFM Commitment Period are set to zero. Second, if for that IFM Commitment period the resource is manually pre-Dispatched under RMR contract, or flagged in Day-Ahead Pre-IFM as RMR pre-Dispatch, then the qualified IFM Start-Up Costs for that IFM Commitment Period are set to zero. Third, if there is no actual Start-Up at the beginning of the relevant IFM Commitment Period, *i.e.*, because the IFM Commitment Period is the continuation of an IFM or RUC Commitment Period from the previous Trading Day, then the qualified Start-Up Costs for that IFM Commitment Period are set to zero. Fourth, If an IFM Start-Up is later delayed or cancelled by a Dispatch Instruction issued through the Real-Time Market, the qualified Start-Up costs for the IFM Commitment Period is zero. Fifth, if the qualified Start-Up costs relating to an IFM Commitment Period is terminated in real time (via an Out of Sequence Shut-Down Instruction) while the unit is actually starting up pursuant to an IFM Start-Up instruction from the prior Trading Day, the qualified IFM Start-Up costs for that IFM Commitment Period are prorated by the ratio of the Start-Up time before termination over the IFM Start-Up time. Sixth, the IFM

Start-Up cost for an IFM Commitment Period is qualified if in the Real-Time an actual Start-Up does not occur within that IFM Commitment Period. An actual Start-Up is detected between two consecutive Settlement Intervals when the relevant metered Energy in these Settlement Intervals increases from below and reaches or exceeds the relevant Minimum Load Energy ("MLE"), which is the product of the relevant Minimum Load and the duration of the Settlement Interval. Finally, The Start-Up Costs for an IFM Commitment Period is qualified if, in Real-Time, an actual Start-Up occurs earlier than the IFM Start-Up, but still within the same Trading Day, and the resource actually stays on until the IFM Start-Up. Otherwise, the qualified Start-Up costs for that IFM Commitment Period is zero.

Q. Why does the CAISO only include qualified Start-Up Costs in determining the Bid costs for resources participating in the IFM?

A. The CAISO will only include qualified Start-Up Costs when determining Bid costs for resources participating in the IFM because of the physical characteristics of those resources (such as ramp rates), because of the fact that those resources may be committed by multiple CAISO market procedures, and because BCR uplift costs, as discussed in greater detail below, are allocated differently for the various commitment processes. For example, because Dispatch instructions are issued through the various CAISO markets, a resource that is committed in the IFM for a set of hours can be operating in Real-Time pursuant to a Start-Up instruction issued by a later commitment process because it is already running, and due to its ramping and shut down rates, was never shut down and continues to run as a result. In such instances it is appropriate to segment the Start-Up Costs so that the resource does not end up receiving an additional Start-Up Cost recovery in a particular market when it has already been compensated for its initial Start-Up in another market. By segmenting and qualifying such Start-Up Costs, the CAISO is able to allocate the Start-Up Costs to the appropriate entities as further described below. Also, if a resource is Dispatched through an RMR Dispatch, that resource will be recovering its Start-Up costs for that interval through its RMR contract. Therefore, it is not appropriate to provide that resource with additional compensation of its Start-Up Costs through the BCR process. Finally, it is not appropriate to allow a unit to recover Start-Up Costs for a Commitment Period during which that resource unit is not actually on, because there are simply no Start-Up Costs for that unit relating to such a Commitment Period.

Q. Please describe IFM pump shut-down costs.

A. For Pumped-Storage Hydro Units and Participating Load only, the IFM Pump and Participating Load Shut-Down Costs for each Settlement Interval are equal to the relevant Pump and Participating Load Shut-Down Cost submitted to CAISO in the IFM divided by the number of Settlement Intervals in a Trading Hour in which shut down is to occur if the unit is committed by the IFM not to pump and actually does not operate in pumping mode in that Settlement Interval (as detected by Metered data).

Q. You also stated that only qualified Minimum Load Costs are included in the determination of a resource's Bid costs. Please explain how and why qualified Minimum Load costs are determined for the IFM Commitment Period.

A. The CAISO will calculate the Minimum Load Costs for each Settlement Interval in the CAISO IFM Commitment Period as the Minimum Load Costs of the relevant resource divided by the number of Settlement Intervals in a Trading Hour. If, however,

a resource is manually pre-Dispatched under the RMR contract, or flagged in the Day-Ahead Pre-IFM as RMR pre-Dispatch in a Settlement Interval, then the qualified Minimum Load costs for that resource during that Settlement Interval are zero. Also, if the resource is not actually on during the relevant Settlement Interval then the qualified Minimum Load costs for that Settlement Interval is also zero. Whether a resource is not actually on is detected by whether the Metered Energy coming from that resource in less than the relevant Minimum Load Energy.

The CAISO considers only qualified Minimum Load costs in calculating Bid costs relating to IFM Commitment Periods for the same reasons that it only includes qualified Start-Up Costs in that calculation. For example, if a unit is pre-Dispatched through an RMR contract, that unit's Minimum Load Costs will be recovered through the RMR contract and therefore should not be recovered and allocated through the BCR mechanism. Also, for the same reason as I explained with respect to Start-Up Costs, if a resource is not actually on then that resource's Minimum Load costs should not be recoverable through BCR.

Q. Please describe IFM pump pumping costs.

A. For Pumped Storage Hydro Units and Participating Load only, the IFM Pump and Participating Load Cost for the applicable Settlement Interval is calculated as the Pumping and Participating Load Bid Cost submitted to the CAISO in the IFM divided by the number of Settlement Intervals in a Trading Hour. The Pump and Participating Load Cost is negative since the MWh quantities are negative. The Pump and Participating Load Cost is included in IFM Bid Cost computation for a Pumped-Storage Hydro Unit and Participating Load committed by the IFM to pump or serve Load, if it actually operates in pumping mode or serves Load in that Settlement Interval.

Q. Please describe IFM Energy Bid Costs.

A. For any Settlement Interval, the IFM Energy Bid Cost is computed as the integral of the relevant Energy Bid submitted to the IFM, if any, from the BCR Eligible Resource's Minimum Load (or self schedule) up to the relevant MWh scheduled in the Day-Ahead Schedule, divided by the number of Settlement Intervals in a Trading Hour.

Q. Please describe IFM Ancillary Services Bid Costs.

A. For any Settlement Interval, the IFM AS Bid Cost is computed as the product of the IFM AS Award from each accepted IFM AS Bid and the relevant AS Bid Price, divided by the number of Settlement Intervals in a Trading Hour.

Q. Will the determination of IFM Bid Costs take into account the non-performance of resources?

A. Yes. The CAISO will set the IFM Bid Costs for a specific resource in any Settlement Interval to zero if the resource's Uninstructed Imbalance Energy ("UIE") for that Settlement Interval exceeds the greater of 1) 5 MWh divided by the number of Settlement Intervals in the Trading Hour, or 2) 3% of the Maximum Capacity divided by the number of settlement intervals in the Trading Hour.

Q. What is the reason for taking into account non-performance in determining a resource's IFM Bid Costs?

A. As stated earlier, BCR eligibility applies only if the resource is not satisfying its obligation under a bilateral arrangement. When a resource self schedules to meet a bilateral contractual obligation, it signals the CAISO that it is self committing and therefore, is not relying on the CAISO to recover its start up and minimum Loads costs for that settlement interval. In fact, based on the rules above, it may forego minimum Load cost recovery for adjacent time periods within the minimum run time of resource.

A resource could easily elect not to inform the CAISO of its bilateral arrangement by self scheduling its contracted Energy, and simply deviate from CAISO instructions in real-time to meet that obligation The proposal to not allow resources that deviate in Real-Time beyond the tolerance band to recover their costs for that interval is designed to deter such behavior.

Q. Above you indicated that unrecovered Bid Costs will be calculated by netting Bids Costs and Market Revenues. How will the CAISO calculate the IFM market revenues for this purpose?

A. The CAISO will calculate the market revenue received by a resource through the IFM, for each Settlement Interval in a CAISO IFM Commitment Period, as the sum of 1) the product of the total Energy scheduled in the IFM for a resource and the relevant LMP, divided by the number of Settlement Intervals in the relevant Trading Hour and 2) the product of all the Ancillary Services capacity awarded to the applicable resource in the IFM multiplied by the relevant ASMP, divided by the number of Settlement Intervals in a Trading Hour. In this computation, for

Pumped Storage Hydro Units and Participating Load operating in the pumping mode or serving Load, the MWh is negative.

The IFM market revues price the minimum Load of the resource or the pump at the relevant LMP.

The CAISO will calculate the market revenue received by a resource through the IFM, for each Settlement Interval not in a CAISO IFM Commitment Period, as the sum of 1) the product of the total Energy scheduled in the IFM for the resource above its minimum Loads or self schedule and the relevant LMP, divided by the number of Settlement Intervals in the relevant Trading Hour and 2) the product of all the Ancillary Services capacity awarded to the applicable resource in the IFM multiplied by the relevant ASMP, divided by the number of Settlement Intervals in a Trading Hour.

2. Calculation of Bid Costs and Market Revenues in RUC

Q. Will the CAISO calculate a separate Bid cost recovery amount for resources committed through the RUC process?

A. Yes. For each Settlement Interval in a RUC Commitment Period, the CAISO will calculate the Bid costs that are to be recovered by a resource committed in the RUC as the sum of the resource's qualified Start-Up Costs , the qualified Minimum Load Costs, and the product of the RUC capacity award with the relevant RUC Bid price divided by the number of Settlement Intervals in a Trading Hour.

Q. Please describe the rules that the CAISO has developed to determine whether RUC Start-Up Costs will be considered qualified RUC Start-Up Costs.

A. The qualified RUC Start-Up Costs are the RUC Start-Up Costs submitted by a Scheduling Coordinator divided by the number of settlement intervals in a RUC Commitment Period. As with IFM Start-Up Costs, the CAISO then applies a series of sequential rules to determine if the RUC Start-Up Costs remain qualified. First, if there is an IFM Commitment Period within the RUC Commitment Period, then the qualified Start-Up Costs for the resource in that RUC Commitment Period are set to zero. Second, if a resource is manually pre-Dispatched under the RMR contract, or flagged in the Day-Ahead Pre-IFM as RMR pre-Dispatch at any point during that RUC Commitment Period, then the qualified Start-Up Costs for the resource in that RUC Commitment Period are set to zero. Third, if there is no actual RUC Start-Up at the beginning of that RUC Commitment Period, *i.e.*, the RUC Commitment Period represents the continuation of an IFM or RUC Commitment Period from the previous Trading Day, then the qualified Start-Up costs for the unit in that RUC Commitment Period are set to zero. Fourth, if the RUC Start-Up is delayed or cancelled by the Real-Time Market, then the qualified Start-Up costs for the unit in that RUC Commitment Period are set to zero. Fifth, if RUC Start-Up is actually terminated in the real-time through an exceptional Dispatch issued while the unit is actually starting up, the resource's qualified RUC Start-Up costs incurred during that RUC Commitment Period will be prorated by the ratio of the Start-Up time before termination over the RUC Start-Up time. Sixth, if an actual Start-Up occurs within a RUC Commitment Period, then the Start-Up Costs for that resource in that RUC Commitment Period is qualified. Finally, if an actual Start-Up occurs earlier than the RUC Start-Up, but still within the same Trading Day, and the resource stays on until the RUC Start-Up, then that resources RUC Start-Up Costs will be treated as qualified, *i.e.*, they will not be set to zero. Otherwise, the qualified Start-Up costs for that unit during that RUC Commitment Period will be set to zero.

Q. Why will the CAISO only include qualified Start-Up Costs in determining the Bid costs that are eligible for recovery in RUC?

A. The CAISO will only count qualified Start-Up Costs for purposes of determining BCR for RUC for the same reasons that I articulated above with respect to the IFM.

Q. How does the CAISO determine qualified Minimum Load costs in the RUC for purposes of calculating BCR?

A. Similarly to the Minimum Load Costs determined for the IFM Commitment Period, the qualified Minimum Load Costs for a Settlement Interval in a RUC

Commitment Period is the Minimum Load Costs of the unit divided by the number of Settlement Intervals in a Trading Hour.

Also similar to the IFM, the RUC Minimum Load Costs will be set to zero if the resource is manually pre-Dispatched under RMR contract, or flagged as RMR pre-Dispatch in the Day-Ahead Pre-IFM, or if the resource is not actually on during a particular Settlement Interval. In addition, if the relevant Settlement Interval is also part of an IFM Commitment Period, then the qualified RUC Minimum Load costs for the unit during that Settlement Interval will be set to zero, because those costs will be recovered through the BCR calculations for IFM, as described above, or if RUC is awarded for a self scheduled resource (i.e., the Settlement Interval is in an IFM Self Commitment Period), the resource is not eligible for minimum Load cost recovery.

Q. Will a unit's RUC Bid Costs be impacted by non-performance?

A. Yes. The CAISO will set the RUC Bid Costs for a specific resource in any Settlement Interval to zero if the resource's Uninstructed Imbalance Energy ("UIE") for that Settlement Interval exceeds the greater of 1) 5 MWh divided by the number of Settlement Intervals in the Trading Hour, or 2) 3% of the Maximum Capacity divided by the number of settlement intervals in the Trading Hour.

Q. What is the reason for setting a resource's RUC related Bid costs to zero under these conditions?

A. The reason for disqualifying RUC related Bid costs under such condition is the same as I explained with respect to the IFM.

Q. How will the CAISO calculate market revenues relating to RUC?

A. For purposes of determining BCR, the market revenues in RUC will be calculated as the product of the quantity of the capacity awarded through RUC and the relevant RUC LMP, all divided by the number of Settlement Intervals in a Trading Hour.

3. Calculation of Bid Costs and Market Revenues in RTM

Q. How does the CAISO calculate the Bid Costs associated with a resource committed in the RTM?

A. Similar to the IFM and RUC, the RTM Bid Costs for a resource in each Settlement Interval in a CAISO RTM Commitment Period is the sum of the qualified RTM qualified Start-Up Costs, the qualified Minimum Load Costs, the relevant RTM Participating Load and Pumped-Storage Hydro Unit shut-down costs, the RTM Energy Bid Costs, and the RTM Ancillary Services Bid Costs.

Q. How does the CAISO determine qualified Start-Up Costs in the RTM?

A. The qualified RTM Start-Up costs are the RTM Start-Up costs submitted by the Scheduling Coordinator divided by the number of settlement intervals in a RTM Commitment Period. As is the case for the IFM and RUC Start-Up Costs, the CAISO applies a series of rules sequentially to determine whether the RTM Start-Up Costs of a resource for a RTM Commitment Period remain qualified. First, if there is a RTM Self-Commitment Period within the applicable RTM Commitment Period, then the resource's qualified Start-Up Costs for that RTM Commitment Period are set to zero. Second, if the resource is pre-Dispatched as RMR (in the Day-Ahead Market or the Real-Time Market) at any time during the RTM Commitment Period, then the qualified Start-Up Costs for the unit for that RTM Commitment Period are set to zero. Third, if there is no RTM Start-Up at the beginning of the RTM Commitment Period, *i.e.*, the RTM Commitment Period is the continuation of an RTM Commitment Period from the previous Trading Day, or the RTM Commitment Period begins at an IFM, RUC, or uninstructed Start-Up, then the resource's qualified Start-Up Costs for that RTM Commitment Period are set to zero. Fourth, the qualified Start-Up Costs for a RTM Commitment Period that is terminated in Real-Time through an exceptional Dispatch issued while the unit is actually starting up will be prorated by the ratio of the Start-Up time before termination over the RTM Start-Up time. Fifth, the Start-Up Costs for a RTM Commitment Period are qualified if an actual Start-Up occurs within that RTM Commitment Period. Sixth, if an actual Start-Up occurs earlier than the RTM

Start-Up, but still within the same Trading Day, and the unit stays on until the RTM Start-Up, the RTM Start-up cost will be considered qualified, otherwise, the qualified RTM Start-Up Costs for the unit during that RTM Commitment Period are set to zero.

Q. How does the CAISO determine qualified Minimum Load Costs in the RTM?

A. A resource's qualified RTM Minimum Load costs for a Settlement Interval are the Minimum Load costs for the resource divided by the number of Settlement Intervals in a Trading Hour, of which there are six. Then, similarly to Minimum Load costs in the IFM and the RUC, the CAISO will apply the following criteria only for Settlement Intervals in a CAISO RTM Commitment Period to determine whether or not those Minimum Load costs are qualified Minimum Load Costs, and thus eligible for recovery. First, if the resource is pre-Dispatched as RMR (in the Day-Ahead Market or the Real-Time Market) in that Settlement Interval, then the qualified Minimum Load Costs for that resource during that Settlement Interval are set to zero. Second, if the resource is not actually on during that Settlement Interval, then the qualified Minimum Load costs for that resource during that Settlement Interval are set to zero. Finally, if that Settlement Interval is part of an IFM or RUC Commitment Period, then the qualified Minimum Load Costs for the resource during that Settlement Interval are set to zero.

Q. Please describe the RTM Energy Bid Costs.

A. A resource's RTM Energy Bid Costs for a Settlement Interval are the sum of the products of each Instructed Imbalance Energy ("IIE") portion, except Standard Ramping Energy, Residual Imbalance Energy, Exceptional Dispatch Energy, and Regulating Energy, multiplied by the resource's relevant Energy Bid prices for each Dispatch Interval in the Settlement Interval.

Q. Please describe the RTM Ancillary Services Bid Costs.

A. A resource's RTM Ancillary Services Bid Costs for a Settlement Interval are the product of the average quantity of AS awarded in the RTM from the resource in the Settlement Interval, reduced by any relevant quantity of capacity that is subject to Tier-1 AS no pay, multiplied by the relevant AS price for that resource. The average RTM AS award for a given Ancillary Service in a Settlement Interval is the sum of the 15-min RTM AS Awards in that Settlement Interval, each divided by the number of 15-minute commitment intervals in a Trading Hour (4) and prorated to the duration of the Settlement Interval -- 10/15 if the RTM AS Award spans the entire Settlement Interval, or 5/15 if the RTM AS Award spans half the Settlement Interval.

Q. Will a resource's RTM Bid Costs be affected by the resource's non-performance?

A. Yes. The CAISO will set the RTM Bid Costs for a specific resource in any Settlement Interval to zero if the resource's UIE for that Settlement Interval exceeds the greater of 1) 5 MWh divided by the number of Settlement Intervals in the Trading Hour, or 2) 3% of the Maximum Capacity divided by the number of settlement intervals in the Trading Hour. The CAISO will do this for the same reason as I explained above with respect to the impact of non-performance on BCR in the IFM and RUC markets.

Q. How will the CAISO calculate the market revenues for units participating in the RTM?

A. For each Settlement Interval in a CAISO RTM Commitment, the CAISO will calculate the RTM market revenue for a unit as the sum of 1) the sum of the products of the Instructed Imbalance Energy (IIE) generated by a resource, except Standard Ramping Energy, Residual Imbalance Energy, Exceptional Dispatch Energy, and Regulating Energy, multiplied by the relevant RTM LMP, for each Dispatch Interval in the Settlement Interval; 2) the product of the quantity of Ancillary Services awarded for the resource, multiplied by the relevant ASMP, divided by the number of 15-minute commitment intervals in a Trading Hour, of which there are four, and prorated to the duration of the Settlement Interval of which there are six in each Trading Hour and 3) minus any Tier 1 no pay charges incurred by the resource, in the Settlement Interval.

For each Settlement Interval in a non-CAISO RTM Commitment period, the RTM Market Revenue for a resource is the algebraic sum of 1) The sum of the products of the Instructed Imbalance Energy, excluding Minimum Load Energy, HASP Self-Scheduled Energy, Standard Ramping Energy, Residual Imbalance Energy, Exceptional Dispatch Energy, and Regulating Energy, with the relevant RTM LMP, for each Dispatch Interval in the Settlement Interval; 2) the product of the quantity of Ancillary Services awarded for the resource, in the Settlement Interval multiplied by the relevant ASMP, divided by the number of 15-minute commitment intervals in a Trading Hour, of which there are four, and prorated to the duration of the Settlement Interval of which there are six in each Trading Hour; and 3) minus the relevant Tier-1 No Pay charges for that resource in that Settlement Interval.

C. <u>Calculation of Unrecovered Bid Cost Uplift</u>

Q. How will the CAISO determine the amount of unrecovered Bid Costs to pay the BCR eligible resources?

A. The unrecovered Bid cost of each resource is computed over the Trading Day as follows: (1) For each of the markets, *i.e.*, the IFM, RUC and the RTM, a resource’s Bid Costs and market revenues in each Settlement Interval are summed algebraically, and the result can be positive or negative. Positive results are considered to be surpluses and negative results are considered to be shortfalls. (2) The surpluses and shortfalls are added algebraically across all hours of the day and across IFM, RUC, and RTM. If the net is a shortfall, it represents the unrecovered Bid cost that the resource will be paid. If the net is a surplus, there is no shortfall to warrant Bid cost recovery.

Q. How will the CAISO determine the amount of unrecovered Bid Costs that are allocated to Scheduling Coordinators during a particular Settlement Interval?

A. As I explained above, only resources that have a shortfall over the Trading Day, receive BCR. For each resource with daily shortfall, the following computations are carried out to allocate the cost of BCR paid to these resources across the markets (IFM, RUC, and RTM) and across the Settlement Intervals.

For each of the markets, *i.e.*, the IFM, RUC and the RTM, a resource's Bid Costs and market revenues in each Settlement Interval are summed algebraically, and the result can be positive or negative. Positive results are considered to be surpluses and negative results are considered to be shortfalls.

For each Settlement Interval of a given Trading Day in each of the CAISO markets, a BCR uplift is calculated as the net of all BCR shortfalls and surpluses from all resources. Thus, the net of all IFM-related shortfalls and IFM-related surpluses for a Settlement Interval from all resources with unrecovered Bid cost payment constitutes the IFM uplift for that Settlement Interval. The net of the RUC-related shortfalls and RUC-related surpluses for a Settlement Interval from all units with unrecovered Bid cost payment constitutes the RUC uplift for that Settlement Interval. And the net of the RTM-related shortfalls and RTM-related surpluses for a Settlement Interval from all units with unrecovered Bid cost payment constitutes the RTM uplift for that Settlement Interval.

In each Settlement Interval, the uplift will be positive if the relevant shortfalls in each market exceeds the relevant surpluses and will be negative if the relevant surpluses exceed the relevant shortfalls.

Q. Does the CAISO then use any positive uplift as the basis for recovering the necessary revenues?

A. Not yet. For the CAISO to be revenue neutral, if the CAISO charges the SCs in the markets and periods where the net cost across all resources is positive (shortfall), then the CAISO will have to pay the SCs in the markets and periods where the net is negative (surplus). This is not compatible with allocation of BCR costs, where only system-wide shortfalls must be recovered. Thus, after the netting that I described in my last response, if the IFM, RUC, and RTM uplifts for a particular Settlement Interval are of different signs, the CAISO nets the negative uplifts against the positive uplifts until the total uplift is zero in the following priority sequence. First, any positive IFM uplift for the Settlement Interval is reduced first by any negative RTM uplift for the Settlement Interval and then by negative RUC uplift for the Settlement Interval. Second, any positive RUC uplift for the Settlement Interval is reduced first by negative RTM uplift for the Settlement Interval and then by negative IFM uplift for the Settlement Interval. Finally, any positive RTM uplift for the Settlement Interval is reduced first by negative RUC uplift for the Settlement Interval and then by negative IFM uplift for the Settlement Interval. This ensures that if that if resources earned revenues in any of the CAISO's markets, those revenues are used to offset the uplift requirements from the other markets. Therefore, if there are significant negative uplifts from the RUC or RTM markets, the positive uplifts payments for the IFM market will be reduced and thereby reducing the uplift allocated to Load.

Q. Is it possible that the uplift amounts allocated to the SCs by the CAISO could be greater than the actual BCR amounts paid to suppliers?

A. No. In order to ensure that the uplift charges allocated to Load are not greater than the amounts actually paid to suppliers, the CAISO sets negative uplifts in each settlement interval for each market (IFM, RUC, or RTM) to $0 and positive uplifts are reduced accordingly. To accomplish this, the following computations are performed. First , all positive and negative uplifts, computed as I described in the previous answer, are summed (algebraically) across all settlement intervals and the three markets (IFM, RUC, and RTM). This is the total uplift that the CAISO will pay to the suppliers. I will refer to this amount as "U." Second, all positive uplifts, computed as I described in the previous answer, are summed across all Settlement Intervals and the three markets. I will refer to this amount as "P." P will always be greater than or equal to U. Then, each positive uplift amount, computed as I described in the answer above, is multiplied by the ratio of U/P, and each negative uplift, computed as I described in the answer above, is set to 0. This ensures that the sum of the positive uplifts allocated to the various Settlement Intervals in the three markets (IFM, RUC and RTM) is exactly equal to the total BCR uplift paid to suppliers for these Settlement Intervals.

D. <u>Allocation of Uplift Associated with Unrecoverd Bid Cost Amounts</u>

Q. How does the CAISO then allocate the resulting Settlement Interval uplift amounts?

A. After determining the uplift amounts associated with each Settlement Interval in each market, each uplift is allocated to Scheduling Coordinators differently.

Q. How will the IFM Uplift be allocated?

A. The hourly IFM uplifts will be allocated by the CAISO in two tiers. In the first tier, the hourly IFM uplifts will be allocated to Scheduling Coordinators in proportion to the amount by which their Demand (which includes internal Demand and Exports) scheduled in a Day-Ahead Schedule through the IFM during the relevant hour exceeds their generation (which includes internal self generation plus Imports) during the relevant hour, adjusted by any applicable IFM uplift Load obligation amounts (as described below) that were traded bilaterally between parties thereby reallocating such Load responsibility. The IFM uplift rate will not exceed the ratio of the hourly IFM uplift in the Trade Hour divided by the sum of all generation scheduled in the Day-Ahead and the Ancillary Services capacity awarded from CAISO-committed Generating Units in that hour. This is to avoid excessively high rate in case the BCR amount to be allocated in the Settlement Interval would have to be allocated to a small quantity of the billing determinant (IFM Load minus self scheduled generation and import). In the second tier, any remaining IFM uplift for the Trading Hour will be allocated to Scheduling Coordinators in proportion to their Metered Demand (which includes internal Demand plus Exports).

Q. Please explain the concept of Inter-SC Trades of IFM Load Uplift Obligations.

A. The CAISO accepts from Scheduling Coordinators Inter-SC Trades of IFM Load Uplift Obligations. These instruments allow Scheduling Coordinators to transfer between themselves uplift obligations associated with BCR in the IFM. The CAISO will validate that these instruments are submitted for parties that agree to the trade and then the CAISO will then subtracts from the transferor's IFM Load

Uplift Obligation the transferred amount and add to the transferee's IFM Load Uplift Obligation the transferred amount.

Q. **Why will the IFM Uplift be allocated in two tiers?**

A. The two-Tier allocation is a usual practice even in today's CAISO markets. When an amount of uplift must be recovered from the SCs based on a billing determinant (e.g., net Load) there may be situations where the billing determinant is small. In that case, a purchase rate is computed, as Tier 1 rate, which is applied to the billing determinant, and the remaining cost is allocated to a wider billing determinant such as Metered Demand. For example, assume the IFM BCR amount in an hour $5,000, the total Load is 1,000 MW, but all SCs have self provided a god portion of their Supply (990 MW). If the total amount of uplift were to be recovered from 1,000 – 990 = 10 MW, this would represent a rate of $500/MWh. The more equitable allocation scheme would be to determine a "purchase" rate, based on the amount of BCR and the quantity of Supply it was paid to in that hour. The purchase rate so computed would then be charged as Tier 1 rate to the 10 MW, and the remaining amount allocated to Metered Demand.

Q. **How will the RUC Uplift be allocated?**

A. The hourly RUC uplift will also be allocated by the CAISO in two tiers. First, the hourly RUC uplift will be allocated to Scheduling Coordinators in proportion to their net negative Load deviations (Metered Load minus Load scheduled in their Day-Ahead Schedules through the IFM) in that hour. The RUC uplift rate will not exceed the ratio of the hourly RUC uplift divided by the sum of incremental RUC Schedule deviations (capacity scheduled through RUC minus the generation scheduled through the IFM) from Generating Units committed by the CAISO through the IFM or RUC for that hour. In the second tier, any remaining RUC uplift for the hour is allocated to Scheduling Coordinators in proportion to their Metered Demand.

Q. How will the RTM Uplift be allocated?

A. Any positive RTM uplift in a Settlement Interval will be allocated to SCs by the CAISO in proportion to their Metered Demand.

Q. Can you provide examples to illustrate the above BCR computation and cost allocation rules?

A. Yes.

Example VIII.1: Calculation of Bid Cost Recovery Amount For A Resource

Consider a generating unit (Unit 1) with start up cost of $1000 and minimum Load cost of $1500 per hour. Its Minimum Run Time is 2 Hours. Unit 1's minimum Load (Pmin) is 50 MW. For simplicity, assume that the unit in ON only for 6 hours during the day.

In the Day Ahead market, Unit 1 self schedules for 80 MW for HE 1, but for hours HE2 through HE6 submits Energy Bids of $25/MWh and RUC Bids of $20/MW/h.

Based on the BCR rules, since the unit has a minimum run time of 2 hours, the unit's self commitment is extended to HE 2 in addition to HE 1. The result is that the unit's IFM Self-Commitment period covers hours HE1 and HE2, and the unit is not eligible for Start-up and Minimum Load BCR during these 2 hours.
In the IFM, the CAISO commits the unit for 80 MW above its Pmin during HE5 and HE6. Assume the LMP at the unit's location is $30/MWh in HE5 and $60/MWh in HE6.

Then assume that Unit 1 receives a RUC award for 30 MW above its Pmin in HE 4, and its RUC LMP is $40/MW/hr.

Finally, in HASP/Real Time ("RT"), the unit self schedules 60 MW during HE 3, but has no accepted Real-Time Bids. So, the unit becomes ineligible for BCR for HE 3 (in addition to HE 1 and HE 2).

Taking into account all of these inputs, , Unit 1 is only eligible for BCR during HE 4, HE 5 and HE 6, as displayed in the following table.

HE 1	HE 2	HE 3	HE 4	HE 5	HE 6
DA Self Commitment		RT Self Commitment	RUC Commitment	IFM Commitment	

Unit 1's Bid costs and revenues in Day Ahead for HE 5 are as follows:

DA Start up cost = $500

DA ML cost = $1500

DA Energy Bid cost = $25/MWh

DA total Bid costs = $500 + $1500 + (25 * 80) = $4000

DA LMP = $30, the DA Market Revenues = 80 * $30 = -$2400

Net revenues = $1600 (shortfall)

Unit 1's Bid costs and revenues in Day Ahead for HE 6 are as follows:

DA Start up cost = $500

DA ML cost = $1500

DA Energy Bid cost = $25/MWh

DA total Bid costs = $500 + $1500 + (25 * 80) = $4000

DA LMP = $60, the DA Market Revenues = 80 * $60 = -$4800

Net revenues = -$800

<u>Unit 1's Bid costs and revenues in RUC for HE 4 are as follows</u>:

RUC Start up cost = 0 (since the RUC Commitment Period is contiguous with the IFM Commitment Period, it includes the IFM Commitment Period; the first rule of RUC Start Up eligibility sets the start up cost to $0)

RUC ML cost = $1500

RUC Availability Bid cost = $20/MW

RUC total Bid costs = $1500 + (30 * $20) = $2100

If RUC LMP = $40/MW, the RUC Market Revenues = 30 * $40 = -$1200

Net revenues = $900 (shortfall)

The sum of Unit 1's net revenues from IFM, RUC and HASP/RT during the eligible BCR periods (HE 4, HE 5, HE 6) is: $1600 - $800 + $900 = $1700, which represents a net shortfall. Therefore, Unit 1 is eligible for Bid Cost Recovery for these hours.

Example VIII.2- Allocation of Bid Cost Recover Charges Across Markets:

For simplicity, in this example we assume identical Dispatch quantities and prices in the 6 settlement intervals of each hour so that computations may be illustrated on an hourly basis.

Assuming that in addition to Unit 1 (from Example VIII.1), there are three additional units participating in the market and that these units' revenues for IFM, RUC and RT[4] for the Trading Day are as follows:

Table 1: Unit 1 Net Revenues

Net Revenues	HE 1	HE 2	HE 3	HE 4	HE 5	HE 6
IFM					$1600.0	-$800
RUC				$900		
RT						

The total net revenues for Unit 1 is a shortfall of $1700 and the unit is eligible for BCR.

Table 2: Unit 2 Net Revenues

Net Revenues	HE 1	HE 2	HE 3	HE 4	HE 5	HE 6
IFM	-$100.0	$600.0	$500.0	-$100.0	$200.0	$400.0
RUC					-$300.0	
RT	$100.0					-$100.0

The total net revenues for Unit 2 is a shortfall of $1200 and the unit is eligible for BCR.

[4] In the Real-Time Market, the settlement intervals are on 10 minute basis. For simplicity, however, the real time results are shown as hourly in this example.

Table 3: Unit 3 Net Revenues

Net Revenues	HE 1	HE 2	HE 3	HE 4	HE 5	HE 6
IFM	$400.0					
RUC	-$600.0	$300.0	$200.0			$100.0
RT		$200.0	-$100.0	-$100.0	$400.0	

The total net revenues for Unit 3 is a shortfall of $800 and the unit is eligible for BCR.

Table 4: Unit 4 Net Revenues

Net Revenues	HE 1	HE 2	HE 3	HE 4	HE 5	HE 6
IFM	$200.0	-$600.0		-$100.0		
RUC	-$600.0		$200.0			$300.0
RT		$300.0	-$100.0	$200.0	$100.0	

The total net revenues for Unit 4 is a surplus of $100. Therefore Unit 4 is ineligible for BCR.

The total net revenues of BCR eligible units (1, 2 and 3) for each market are shown in Table 5.

Table 5: Total Net Revenues of Units 1,2,3

Net Revenues	HE 1	HE 2	HE 3	HE 4	HE 5	HE 6
IFM	$300.0	$600.0	$500.0	-$100.0	$1,800.0	-$400.0
RUC	-$600.0	$300.0	$200.0	$900.0	-$300.0	$100.0
RT	$100.0	$200.0	-$100.0	-$100.0	$400.0	-$100.0

The following rules are applied to determine the BCR uplift for each market. If the IFM, RUC, and RTM uplifts for a Settlement Interval are of different signs, negative uplift is used to reduce positive uplift (until zero) in the following priority sequence: a) Any positive IFM uplift is reduced first by negative RTM uplift and then by negative RUC uplift; b) Any positive RUC uplift is reduced first by negative RTM uplift and then by negative IFM uplift; and c) Any positive RTM uplift is reduced first by negative RUC uplift and then by negative IFM uplift. The results are shown in Table 6.

Table 6: Adjusted Net Revenues of Units 1,2,3

Net Revenues	HE 1	HE 2	HE 3	HE 4	HE 5	HE 6
IFM	$0.0	$600.0	$400.0	$0.0	$1,500.0	-$400.0
RUC	-$200.0	$300.0	$200.0	$700.0	$0.0	$0.0
RT	$0.0	$200.0	$0.0	$0.0	$400.0	$0.0

To ensure that only uplift charges are allocated to Load, negative uplifts in each settlement interval for each market (IFM, RUC, or RTM) are set to $0 and positive uplifts reduced accordingly. To accomplish this, the following computations are performed:

a) Adding (algebraically) all positive and negative uplifts computed across all settlement intervals and the three markets (IFM, RUC, and RTM) results in $3700 as shown in Table 7. This is the total uplift paid to the suppliers eligible for Bid cost recovery.

b) Adding only the positive uplifts across all settlement intervals and the three markets results in $4300.

Table 7: Total Uplifts and Positive Uplifts

	Total Uplifts	Positive Uplifts
IFM	$2,100.0	$2,500.0
RUC	$1,000.0	$1,200.0
RT	$600.0	$600.0
Total	$3,700.0	$4,300.0

c) The ratio of total uplifts to positive uplifts is $3700/$4300 or 86%.

d) Each positive uplift is multiplied by 86% and each negative uplift is set to zero.

This ensures that the sum of the positive uplifts allocated to the various settlement intervals in the three markets (IFM, RUS and RTM) is exactly equal to the total Bid cost recovery uplift paid to the generators. The results are shown in Table 8.

Table 8: Uplifts for each market for each settlement period

Uplifts	HE 1	HE 2	HE 3	HE 4	HE 5	HE 6
IFM	$0.0	$516.3	$344.2	$0.0	$1,290.7	$0.0
RUC	$0.0	$258.1	$172.1	$602.3	$0.0	$0.0
RT	$0.0	$172.1	$0.0	$0.0	$344.2	$0.0

The uplift costs computed in Table 8 are now allocated to SCs separately for each market (IFM, RUC, and RTM) and for each settlement interval.

Example VIII.3 - BCR Cost Allocation to Individual SCs:

Assume there are only three SCs in Example VIII.2. This example illustrates how the BCR amount computed for each market (IFM, RUC, and RTM) for each Settlement Interval is allocated to the SCs. We will consider HE2 for illustration.

IFM BCR Allocation:

Assume that for HE2 the total IFM Scheduled Generation and AS Award is 500 MW. Consider the following data for the three SCs:

	IFM Demand less Self Scheduled Supply (MWh)	Measured Demand (MWh)
SC1	200	300
SC2	100	300
SC3	100	200
Total	400	800

Since the IFM BCR is $516.3 for HE2, and the total IFM Demand less self scheduled Supply (400) is less than the total IFM Scheduled Generation and AS award (500), the Tier 1 rate is $516.3/MAX(500, 400) = $1.03/MWh. However, this rate is not sufficient to recover all IFM BCR since $1.03* 400 = $413. The shortfall of $516.3 - $413 = $103.3 is allocated to measured Demand. The following Table summarizes the IFM BCR cost allocation for HE2.

	Tier 1 MWh	Tier 2 MWh	Tier 1 Amount ($)	Tier 2 Amount ($)	Total ($)
SC1	200	300	$206.5	$38.7	$245.2
SC2	100	300	$103.3	$38.7	$142.0
SC3	100	200	$103.2	$25.9	$129.1
Total	400	800	$413.0	$103.3	$516.3

RUC BCR Allocation:

Assume that for HE2 the total RUC Award is 500 MW. Consider the following data for the three SCs:

	IFM Load Schedule (MWh)	Measured Demand (MWh)	Real-time Exports (MWh)	Load Deviation (MWh)
SC1	150	300	50	(300 – 50) -150 = 100
SC2	80	300	20	(300 – 20) -80 = 200
SC3	70	200	30	(200 – 30) -70 = 100
Total	300	800	100	400

Since the RUC BCR is $258.1 for HE2, and the total Load Deviation (400) is less than the total RUC award (500), the Tier 1 rate is $258.1/MAX(500, 400) = $0.52/MWh. However, this rate is not sufficient to recover all RUC BCR since $0.52* 400 = $206.5. The shortfall of $258.1 - $206.5 = $51.6 is allocated to Measured Demand. The following Table summarizes the IFM BCR cost allocation for HE2.

	Tier 1 MWh	Tier 2 MWh	Tier 1 Amount ($)	Tier 2 Amount ($)	Total ($)
SC1	100	300	$51.6	$19.4	$71.0
SC2	200	300	$103.3	$19.4	$122.7
SC3	100	200	$51.6	$12.8	$64.4
Total	400	800	$206.5	$51.6	$258.1

RTM BCR Allocation:

The RTM BCR is allocated to Measured Demand. With the above Measured Demand data, the RTM BCR of $172.1 for HE2 is allocated among the three SCs in proportion to their Measured Demand as follows:

	Measured Demand	RTM BCR Charge Amount ($)
SC1	300	$64.5
SC2	300	$64.5
SC3	200	$43.1
Total	800	$172.1

IX. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator) **Docket No. ER06-___-000**
Corporation)

I, Farrokh Rahimi, declare under penalty of perjury, that the foregoing questions and answers labeled as my testimony were prepared by me, with the assistance of others working under my direction and supervision; and that the facts contained in my answers are true and correct to the best of my knowledge, information and belief.

Executed on: Feb. 6, 2006
Date

Farrokh Rahimi

Farrokh A. RAHIMI, Ph.D.
Principal Market Engineer, California ISO
Folsom, CA 95630

Education

Ph.D. in Electrical Engineering from Massachusetts Institute of Technology (M.I.T.), 1970
M.Sc. in Electrical Engineering from Massachusetts Institute of Technology (M.I.T.), 1968
B.Sc. in Electrical Engineering from American University of Beirut (A.U.B.), Lebanon, 1966

Summary Qualifications

Dr. Rahimi has 35 years of experience in electric power systems analysis, planning, operations, and control, with the most recent 12 years in the design, implementation, analysis and monitoring of the restructured electricity markets. He has managed and technically contributed to large and complex projects in these areas in North America, Europe, Middle East, Asia and Latin America. He is an expert in restructured electricity market design and the related systems including the operations, commercial, and business systems and market monitoring applications, and is intimately familiar with the design and implementation of the existing ISOs and RTOs in North America.

Employment History

Sep. 05 - present Principal Market Engineer
California ISO, Folsom, CA

Main responsibilities include resolution of Market Redesign & Technology Upgrade (MRTU) policy issues; assistance with MRTU Tariff development; review of MRTU software design as relevant to ensure consistency between market design policy, Tariff development, and software design. Other responsibilities include design and development of simulation studies to support policy resolution, and collaboration with other CAISO departments as relevant, particularly the Market Monitoring, Operations, and Settlements departments.

Aug. 97- Sep 05 Self employed
DBA: Open Access Consulting (OPAC), Granite Bay, California

(Feb. 1998 – Sep. 2005): Consultant to the California Independent System Operator (CAISO). Primary responsibility at CAISO included services to CAISO Department of Market Analysis (DMA) in monitoring of the deregulated electricity market in California, services to CAISO Regulatory Policy Office in market redesign (LMP-based Market Design & Technology Upgrade project, Resource Adequacy, Transmission Rights, etc.), and collaboration with the CAISO Operations and Settlement departments in defining functional requirements for bidding, scheduling and settlement systems.

(Aug. 1997-Jan. 1998): Collaboration with the California ISO Alliance (Perot Systems, ABB Systems Control, Inc., and Ernst & Young) in the design and implementation of scheduling applications (ancillary services, congestion management, and balancing energy markets).

Other activities and projects included collaboration in inter-RTO seams issues, including the Seams Steering Group - Western Interconnection (SSG-WI), consulting services to Bonneville Power Administration/Northwest Security Coordinator, Ontario Independent Market Operator (IMO), and Jordanian Electricity Authority, as well as educational courses and seminars in collaboration with well-known domestic and international organizations.

1989 - 1997 Senior Principal Engineer
Macro Corporation (now KEMA Consulting), Mountain View, California, U.S.A.

(1996-1997): Project manager for the California WEPEX project involving development of functional specifications for the California Independent System Operator (CAISO) and Power Exchange (CalPX) Business Systems, including Bidding, Scheduling, Settlement, and Billing systems. The project team consisted of a consortium of Macro Corporation, KEMA-ECC and Coopers & Lybrand (now part of Price-Waterhouse Coopers). Dr Rahimi was the project manager responsible for day-to-day operation of the project, and brought the project to successful conclusion within time and budget despite changes in the market design resulting from ongoing discussions and negotiations among the different parties implicated in California Energy Market restructuring.

(1989-1996): Project manager and principal contributor to utility restructuring projects in Europe, Canada, and the U.S. Also, managed large and complex projects in energy planning as well as real-time control and communication systems for electric power utilities in the U.S., Canada, Egypt, Hungary, India, Poland, and Switzerland.

1984 - 1988 Manager, Energy Systems Department
(also 1974 -76) Systems-Europe, Brussels, Belgium

Managed energy planning projects conducted for the European Economic Commission (EEC) member states. In this position, Dr. Rahimi was also responsible for the design of an Energy model for Europe, the Energy Flow Optimization Model (EFOM), subsequently used widely in the EEC member states and countries with which EEC had cooperation programs in the Energy field.

Managed and technically contributed to energy economic analysis, energy planning, and energy conservation programs in China, Yugoslavia, Mexico, Venezuela, and Brazil. The projects were mainly sponsored by the European Energy Commission (EEC).

Managed and technically contributed to energy planning and electric power system operations and control projects in Europe and the Middle East.

1983 - 1984 Principal Research Engineer
Brown Boveri, Baden, Switzerland

Responsible for research and development in power system planning and operation, with emphasis on advanced power system applications, including on-line Dynamic Security Analysis for more efficient and reliable utilization of the transmission system.

1976 - 1982 Professor of Electrical Engineering
(also 1972-74) Arya-Mehr (Sharif) University of Technology, Tehran, Iran

Teaching and Research: Teaching and research in electric power system analysis, planning, operations and control, control and communication systems, and supervision of several graduate theses.

Industry: Transmission planning studies and consulting activities for the energy sector and electric utility industry in the Middle East and Europe, in collaboration with Systems Europe, the European subsidiary of Systems Control, Inc.

1970 – 1972 Systems Control Inc. (now ABB Systems Control), Palo Alto, California: Started as Senior Research Engineer; continued as associate while pursuing projects in the Middle East and Europe in collaboration with Systems Europe.