CALIFORNIA ISO

California Independent
System Operator

February 24, 2004

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

Re: Docket No. ER02-1656-000
California Independent System Operator Corporation

Dear Secretary Salas:

Enclosed for electronic filing please find the Comments of the California Independent System Operator Corporation Regarding Technical Conference in the above captioned docket.

Thank you for your assistance in this matter.

Respectfully submitted,

Anthony J. Ivancovich
Counsel for The California Independent
System Operator Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	Docket No. ER02-1656-000

COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION REGARDING TECHNICAL CONFERENCE

Pursuant to the "Notice Establishing Due Dates For Filing Comments Arising From January 28-29 Staff Technical Conference And Announcing Location For March 3-5 Staff Technical Conference" ("Notice"), the California Independent System Operator Corporation ("ISO")[1] hereby submits its Comments regarding the technical conference held in the captioned proceeding on January 28-29, 2004 ("MD02 Technical Conference").

In support hereof, the CAISO respectfully states as follows:

I. BACKGROUND

On July 22, 2003, the CAISO filed a Revised Comprehensive Market Design Proposal ("MD02 Filing") with the Federal Energy Regulatory Commission ("Commission"). On October 28, 2003, the Commission issued a "Further Order On The California Comprehensive Market Redesign Proposal." *California Independent System Operator Corporation*, 105 FERC ¶ 61,140 (2003) ("October 28 Order"). In its October 28 Order, the Commission approved in principle many of the conceptual market design elements submitted by the ISO. The Commission also provided guidance as to other issues and sought additional

---

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

explanation of and information regarding other elements. The Commission emphasized that its October 28 Order provided guidance only and that the order was advisory in nature. Accordingly, the Commission stated that the parties would be permitted to revisit the issues addressed by the Commission *de novo* after the ISO files its comprehensive tariff. October 28 Order at P 2.

The Commission Staff convened a technical conference in Washington, D.C., on January 28-29, 2004. Issues discussed at the MD02 Technical Conference included, *inter alia*, (1) the Commission's flexible must offer proposal ("FOO"); (2) the residual unit commitment ("RUC") process; (3) pricing for constrained output generators; (4) marginal losses; and (5) Ancillary Services ("A/S") procurement. The parties spent a significant amount of time addressing each of these matters. At the end of the MD02 conference, the Commission Staff directed the parties to file comments on the technical conference. The Notice established February 24, 2004 as the date for the ISO to file substantive comments responding to the comments of other parties.

The instant Comments set forth the ISO's positions on the issues addressed at the technical conference and arguments raised in parties' comments. As a result of parties' comments and the discussion at the MD02 Technical Conference, the ISO is submitting for the parties' consideration and for discussion at the March 3-5 technical conference several proposed modifications to the Revised Comprehensive Market Design Proposal. These proposed modifications are as follows: (1) a revised proposal for compensating RUC resources that attempts to balance several legitimate objectives and concerns;

(2) a requirement that RUC capacity serve ISO-Control Area load; (3) revised treatment of constrained output generators ("COGs")[2]; and (4) slight modifications to the ISO's A/S procurement policy.[3] The ISO looks forward to discussing these new proposals with stakeholders at the March 3-5, 2004 technical conference in San Francisco. In these Comments, the ISO also (1) responds to specific comments submitted by the parties, (2) describes its operational concerns with the FOO proposal, (3) submits additional support for its proposed treatment of marginal losses and the need to procure energy from imports in the RUC process, and (4) identifies some concerns and provides some initial ideas regarding simplification of the Hour Ahead market for discussion at the March 3-5 technical conference.

II. COMMENTS

A. Flexible Offer Obligation

In its MD02 Filing, the ISO proposed to retain the existing Real-Time ("RT") Must Offer Obligation for suppliers (other than hydro resources). In addition, the ISO proposed to implement a Day Ahead ("DA") Must Offer Obligation. In the October 28 Order, the Commission rejected the ISO's proposal to extend the Must Offer Obligation to the DA market. October 28 Order at P 73. As an alternative to the ISO's proposal, the Commission offered for consideration a blending of the RT Must Offer Obligation with the proposed DA Must Offer Obligation. *Id.* The so-called Flexible Offer Obligation ("FOO") would give

---

[2] The ISO also is providing information in response to the Commission Staff's request that the ISO identify the number, size and location of all COGs, indicating whether the unit's output is constrained by transmission.

[3] The ISO's proposed modifications to its Revised Comprehensive Market Design Proposal are set forth in Attachment A.

suppliers the option to fulfill their Must Offer Obligation by bidding into either the DA market or the RT market. *Id.* at P 74. In its January 24, 2004 "Notice of Agenda of Staff Technical Conference" ("January 24 Notice"), the Commission raised the following questions for the parties: (1) how will the implementation of the FOO affect DA and RT market timelines; (2) to what extent does the FOO provide adequate incentive to suppliers to participate in the ISO's markets and provide the ISO with the reliability it needs; and (3) why, if at all, do slow start units present special circumstances that justify exempting them from FOO requirements and identify any alternatives for slow-start units to protect themselves from un-recovered start-up and minimum load costs by bidding into the DA market.

The ISO generally supports the concept of a Flexible Offer Obligation;[4] however, the ISO does have some operational concerns regarding the functioning of FOO. These concerns, which need to be addressed and resolved satisfactorily, are described below. The ISO believes that the FOO, in conjunction with RUC, could replace the existing MOO and the Must Offer Waiver procedure in a systematic and effective manner, provided the ISO's operational concerns are resolved.

Certain parties allege that FOO is unnecessary (Powerex Comments at 6) and that FOO should only be a temporary measure pending implementation of a

---

[4] The Northern California Power Authority ("NCPA") claims that the ISO has backpedaled and is now uncertain whether FOO applies to Metered Subsystems ("MSS") entities. The ISO does not know whether or not the Commission intended FOO to apply to MSS entities. FOO is the Commission's proposal not the ISO's proposal. NCPA should seek clarification from the Commission as to whether the Commission, in its October 28 Order, intended FOO to apply to MSS entities. The ISO notes that MSS entities are not subject to the existing Must Offer Obligation. Further, in the MD02 Filing, the ISO proposed to exempt MSS entities from the RT and DA Must Offer Obligation.

comprehensive resource adequacy program (Duke Comments at 2).[5] The ISO disagrees with those comments. FOO is not a resource adequacy issue. The purpose of FOO is to prevent physical withholding of supply resources. FOO will protect consumers against physical withholding and promote a stable and competitive market. In addition, the ISO believes that FOO could be an appropriate tool to help the ISO maintain reliable grid operations. Further, FOO provides suppliers with more flexibility than they have today under the existing Must Offer Obligation.[6] As such, FOO should be a permanent feature of the market and not be eliminated once the State's resource adequacy program is in place.

As noted above, the ISO has identified some potential operational concerns with the FOO that need to be addressed. The main concern arises in relation to long –start-time units ("LSTs") that do not bid into the DA market.[7] Under the FOO mechanism proposed by the Commission, these units would be required to be on-line in Real-Time for all 24 hours of the following day, operating at least at minimum load. During off-peak hours, this could result in an over-

---

[5] Reliant argues that FOO should not be implemented in isolation without a properly designed resource adequacy program. Reliant Comments at 1. Williams argues that FOO should be contingent upon the development of a resource adequacy mechanism that compensates suppliers for the provision of capacity in the Day Ahead time frame. Williams Comments at 6. As the parties are well aware, the California Public Utilities Commission approved a resource adequacy program at its January 22, 2004 meeting. In its White Paper on Wholesale Power Market Platform ("White Paper") issued on April 28, 2003 in Docket No. RM01-012, the Commission placed the responsibility for developing a resource adequacy plan solely with the states. Thus, the Commission should not condition FOO on the State's implementation of a resource adequacy program that contains specified mechanisms that certain parties desire.

[6] Therefore, FOO should be more palatable to suppliers than either the existing RT Must Offer Obligation and Must Offer Waiver procedure or the Must Offer proposal contained in the ISO's MD02 Filing.

[7] For the purposes of the FOO, the ISO proposes to define LST units as those which require five hours or more start-up time. The rationale for this definition is set forth below.

generation situation with too many units being on. In particular, the ISO is concerned that too many units would be running at Minimum Load late at night or early in the morning (when demand is low) if all of the units that did not participate in the DA market show up in Real-Time in every hour of the next day. In contrast, if a LST unit that is shut down does participate in the DA IFM, the ISO can develop a 24-hour, shaped schedule for the resource, keeping it off-line during low-load hours to avoid over-generation conditions and bringing it on-line when the ISO expects to need the unit. In order to avoid over-generation problems in these circumstances, the ISO will still need some transparent mechanism for (1) granting waivers to FOO resources that are not needed to be on-line and (2) specifying the hours of the next day when the ISO expects that such units will need to be available in Real-Time, regardless of whether the resources elect to participate in the DA integrated forward market. Under these circumstances, the ISO submits that the FOO should be augmented with some type of "pre-emptive waiver" mechanism; although, the ISO is not prepared to describe a detailed proposal on this matter at this time. The ISO will be prepared to discuss this issue further with stakeholders at the March 3-5 technical conference in San Francisco and develop more detailed guidelines for implementation of FOO. As discussed at the MD02 Technical Conference, the ISO understands the Commission's FOO proposal to refer to a two-settlement market design (*i.e.*, DA and RT only). At the MD02 Technical Conference, ISOdescribed its concept of how FOO would work in a three-settlement market design that includes an Hour-Ahead ("HA") market. The concept revolves around the ability of the ISO to consider FOO resources having different start-up times in the DA and HA markets, thereby making more efficient use of those resources, while still providing the resource owners with greater flexibility in fulfilling their obligations under FOO. If the Commission approves the FOO mechanism, the Commission should confirm that the following features will be incorporated into the FOO design.

First, LST FOO resources, *i.e.*, units with a start-up time longer than five hours, should not be exempt from FOO. Rather, in order for a LST to obtain the equivalent of a Must Offer Waiver (*i.e.*, permission from the ISO not to be available in RT), such unit must (1) not self-schedule or self-commit in the DA market, and (2) bid into the DA market, but not be committed by the ISO in either the IFM or RUC. Alternatively, if the concept of a pre-emptive waiver is incorporated into the FOO design, the unit could avoid the DA market and still be exempted from its RT obligation for some or all hours of the next day. Under these circumstances, the unit would be granted a waiver of its FOO for the following day and may shut down (or not start up if already shut down) for that day. If, on the other hand, the unit stays out of DA market, then absent a pre-emptive waiver it should be required to self-commit and be on-line and available in RT.

LSTs should be defined as those units requiring at least five hours start-up time. This is appropriate because five hours is the time horizon of the HA RUC procedure which the ISO proposes to perform each hour immediately following the HA IFM. FOO resources that have start-up times between one and five hours (which can be deemed to be "medium start-time" or MST units) can therefore opt out of the DA market and still be committed by the ISO in the HA IFM or RUC if needed.[8] By analogy to the discussion in the previous paragraph, a MST unit could receive an ISO waiver of its RT obligation for a period equal to its start-up time by (1) not self-scheduling or self-committing in the HA market, and (2) bidding into the market and not being committed by the ISO in either the IFM or RUC. The concept of pre-emptive waiver would also apply in this instance in a manner analogous to its application in the DA. Absent the extension of the Commission's FOO proposal to the HA market as described above, all MST FOO resources that did not schedule or bid in the DA market would automatically be required to be on-line and available for dispatch for all 24 hours of the following day. Thus, applying the FOO to the HA market provides the owners of these resources with greater flexibility and enables the ISO to utilize such units more efficiently.

Second, the only way for LST units to receive ISO-guaranteed start-up and minimum load ("SU/ML") costs should be for such units not to self-commit, and to bid into the DA market and be committed by the ISO in either the DA market or RUC. If such a resource stays out of DA market and is not issued a waiver by the ISO, then it is self-committing (*i.e.*, covering its own SU/ML costs) to satisfy its obligation to be available in the Real Time market. This provision would apply analogously to MST units with respect to the HA market.

---

[8] FOO resources with start-up times less than one hour can simply bid into the RT market, which closes to bidding at 60 minutes prior to the start of the operating hour, and be committed by the ISO in the RT pre-dispatch process to be available during the next operating hour.

Third, resource owners that are subject to FOO should not be permitted to transfer the ability to physically withhold to another party through a contract. For example, if a supplier has a bilateral contract with a buyer that allows the buyer to dispatch the resource, the resource owner should not be able to use the contract as an excuse to withhold (*i.e.,* the resource owner cannot withhold the resource from the RT market and claim "my contract made me do it" because the buyer did not dispatch the resource).[9] As the ISO clarified at the MD02 technical conference, in all cases it is the Scheduling Coordinator ("SC") for the resource who should be accountable for FOO compliance.

As a final matter, the Commission should confirm that a FOO resource that has not received a preemptive waiver from the ISO and does not self-commit or bid to sell energy or A/S in a forward market will be required to be available for RT dispatch by the ISO. In other words, the only way for a LST or MST resource that has not been given a preemptive waiver to obtain a waiver of its RT obligation is to bid into the last market in which it can be committed (*i.e.,* DA for LSTs and HA for MSTs) and not be committed by the ISO in that market's IFM or RUC process.

---

[9] The issue of LSEs retaining all dispatch rights to contracted resources has been raised specifically with regard to the ability of LSEs to follow their own load. Although the ISO's July 2003 Proposal would allow MSS to follow their own load in real time, it is the ISO's role and responsibility to perform real-time load following (*i.e.*, system balancing) for all other ISO Control Area loads. Customers of the non-MSS LSEs benefit from this approach because the ISO's system-wide economic dispatch will balance the system in the most economically efficient manner. Therefore, with the exception of MSS resources, exemptions from FOO for such purposes is not appropriate.

B. Residual Unit Commitment

1. Background

In its October 28 Order, the Commission approved the ISO's RUC proposal in concept, but recommended several modifications to the proposal. First, the Commission rejected, without prejudice, the ISO's proposal to procure energy (as opposed to capacity) from imports in the RUC process. October 28 Order at P 127. However, the Commission recognized that the ISO raised a concern that the mere purchase of capacity might not provide sufficient incentive to imports to acquire the necessary transmission capacity across the ties. Accordingly, the Commission urged the ISO to submit additional clarification on this point.[10] *Id.*

Second, the Commission made several revisions to the ISO's RUC proposal to provide an Availability Payment to units that are selected in the RUC process. In that regard, the Commission rejected the ISO's proposed $100/MWh Availability Payment bid cap and, instead, approved a $250/MWh bid cap. October 28 Order at P 123. Further, the Commission ruled that the Availability Payment should not be rescinded if the RUC unit is ultimately awarded Ancillary Services or dispatched for energy in the Hour-Ahead or Real-Time Markets.[11] *Id.*

---

10 The ISO addressed this issue in a Clarification of CAISO Market Design Issues filed on January 14, 2004 in the captioned docket ("January 14 Clarification").

11 The Commission noted that, in its MD02 Filing, the ISO made the statement that it "does not prohibit energy from capacity committed in the Day-Ahead RUC from being sold by the unit owner via any bilateral transaction in the hour-ahead market, including sales to other Control Areas." October 28 Order at P 123. The Commission found this statement to be contrary to the ISO's statements elsewhere that the ISO needs RUC capacity as a reliability backstop when the day-ahead market closes significantly below the ISO's forecasts. In other words, units committed in RUC are free to sell elsewhere, *i.e.*, not be committed. The Commission requested further

at P 124. Moreover, the Commission concluded that Availability Payment bids should be permitted to set a market clearing price ("MCP") rather than be paid "as bid."[12] *Id.* at P 123.

Third, with respect to the recovery of Start-Up and Minimum Load costs, the Commission denied the ISO's proposal to net the recovery of SU/ML costs against market profits, without prejudice to the ISO re-submitting its proposal upon implementation of a resource adequacy program. October 28 Order at P 115. The Commission declined to rule on the issue of whether the cost-based bid option should recognize daily spot gas prices. *Id.* at P 110. Finally, the Commission rejected suppliers' claims that in-state transportation costs should be included as a component of the cost-based option for start-up and minimum load cost recovery. *Id.* at P 112.

In its January 21 Notice, Commission Staff raised the following questions regarding RUC:

- Energy Procurement Target
    - Why is energy procurement needed if procured capacity can ensure reliability?
    - Explain what impacts the procurement of energy could have on the DA market, *e.g.*, discouraging load from bidding.
    - Would energy purchased through RUC receive a different price than energy procured from the DA market? Explain.
    - Who would pay for energy that was procured but ultimately not needed?
- Treatment of and obligations for imports
    - Explain the extent to which the purchase of only capacity (not energy) gives imports sufficient incentive to acquire the necessary transmission capacity across the ties.

---

clarification of this aspect of the ISO's July 22 MD02 Filing. The ISO addressed this issue in its January 14 Clarification.

[12] At the MD02 Technical Conference, Commission Staff clarified that the Commission's intent was not to set a single system-wide MCP; rather, the Commission contemplated a nodal MCP for RUC capacity.

- Rescission of RUC availability payment
    - How does the RUC availability payment differ from a call option?
    - How does the RUC availability payment differ from offering operating reserve capacity?
- Netting of start-up/minimum load (SU/ML) costs
    - What are the pros and cons of permitting units that are committed in the DA market to receive payment to cover SU/ML costs in the DA market and retain all revenues for subsequent sales?
- Obligations from commitment in DA market and RUC
    - Explain how, if at all, units committed to supply capacity in RUC are obligated to offer energy in real time. What are the impacts to markets?
- Discussion of use of daily or monthly gas indices in cost-based option for SU/ML costs.

The aforementioned issues were discussed at the MD02 Technical Conference. In response to that discussion and the comments filed by the parties, the ISO is proposing several modifications to its RUC proposal. These modifications are set forth below. In addition, the ISO addresses certain parties' comments regarding the RUC proposal and further emphasizes the ISO's need to acquire energy from imports in the RUC process.

2. The ISO's Revised RUC Proposal

Based on the discussion at the MD02 technical conference and after reviewing the parties' comments, the ISO is proposing the following revisions to its RUC proposal for discussion at the March 3-5 technical conference:

1. The bid cap on the Availability Payment will be $150. (The ISO originally proposed a $100 cap and FERC approved a $250 cap in its October 28 Order.)

2. The Availability Payment will be paid on a locational MCP basis. The ISO has not yet fully developed the details of how this would operate, but will be prepared to provide further details for discussion at the March 3-5 technical conference. It is important to note that payment of a locational

MCP creates a need for local market power mitigation with respect to RUC capacity (*see infra* for proposal on this issue.)[13]

3. The Availability Payment will not be rescinded if a unit is dispatched in the energy markets subsequent to the RUC process (for the same operating hour). (The ISO originally proposed that 100% of the "Availability Payment" would be rescinded if the unit was dispatched in the energy market subsequent to RUC. The Commission ruled that no portion of the "Availability Payment" should be rescinded.)

4. The combined Availability Payment received in RUC and Energy MCP received in energy markets subsequent to RUC cannot exceed $250. This is necessary to avoid potential economic withholding from the DA IFM. Specifically, this measure is necessary to avoid potential disincentives against supplier participation in the DA market and preferential participation in the RT market. Without such a measure, the Availability payment would effectively raise the RT price cap to $400 (the sum of the Availability Payment and real-time energy bid caps under the ISO's proposal). (This is a new provision.)

5. The portion of a unit's output that is mitigated in the pre-IFM run for local market power in the Energy market and does not clear the IFM, will be preserved in RUC (*i.e.*, slated as RUC capacity) and will be eligible to receive a RUC Availability Payment in addition to the Energy payment that it receives in the market (hour-ahead or real-time) where its Energy is eventually scheduled or dispatched. However, because of its local market power, the unit's RUC Availability bid will be subject to mitigation, *i.e.*, it will be set at the lower of the unit's Availability bid price or a mitigated reference level. The unit can, however, collect a higher Availability Payment MCP (LMP) that may be set at its location by other accepted Availability bids. Mitigated Availability bid prices could be based on competitive Availability bid reference levels, *e.g.*, the mean or median of system-wide Availability MCPs for the preceding 90 days. (This is a new provision).

6. Recovery of Start-Up and Minimum Load Costs shall be net of market revenues (A/S, energy profits (defined as MCP – bid) and RUC Availability Payments). (This is consistent with the ISO's original proposal. The Commission rejected the netting proposal without prejudice when a resource adequacy program is implemented.)

---

[13] The ISO also notes another potential complexity for discussion at the March 3-5 technical conference: namely, it may not be feasible for the RUC optimization to consider energy bid curves as well as Availability bids in procuring RUC capacity at locational MCPs.

7. Intrastate gas transportation and municipal use fees shall be included in minimum load energy costs. (These costs were not included under the ISO's original proposal or under the October 28 order.)

8. Use RMR Contract gas costs for RUC. This would involve using a two-day average of three daily indices (NGI So Cal Border, BTU So Cal Border and Gas Daily So Cal Gas large package) for SCE or SDG & E units, and a two-day average of two daily indices (NGI PG & E Citygate and Gas Daily PG & E citygate) for former PG & E units, plus any applicable intrastate transportation and municipal use fees. (This is a new provision.)

9. RUC capacity procured in the DA would be prevented from being used to serve export schedules in the HA. This is different from the ISO's previous proposal because DA RUC capacity would now be paid to serve ISO load (*i.e.*, there is no rescission of the Availability Payment). The ISO is considering two possible ways to implement this provision. Method 1 would involve enforcing a new constraint in the HA IFM: incremental exports are constrained to be less than or equal to incremental imports plus incremental generation from non-DA RUC capacity. Under this formula, DA RUC capacity would be available to be scheduled against control area load in the HA. Moreover, HA incremental exports could not cut into the DA RUC capacity even if some of that capacity is not scheduled against control area load in HA. The ISO has not yet worked through the implementation details for this method and, at this time, is not certain how easy or difficult it may be to incorporate this constraint in the optimization. Method 2 is much simpler – the ISO would simply prohibit export purchases in the HA IFM.

10. RMR dispatches that occur in RUC would not be eligible for setting or receiving the availability MCP. Similarly, any unit pre-designated as a capacity resource under a load serving entity's ("LSEs ") resource adequacy plan would not be eligible to receive or set the RUC availability MCP, provided both the resource owner and the LSE agree to this treatment.[14]

The above proposal reflects a delicate balance of the following objectives: (1) providing adequate incentives for load to forward schedule; (2) ensuring that

[14] One approach for implementing this may be through a RUC "self-provision" mechanism. The ISO has not yet developed a proposal for how such a mechanism would work, but offers some ideas later in this section. The ISO would like to discuss this possible approach at the upcoming technical conference.

market power – including local market power – is adequately mitigated; (3) providing fair compensation to suppliers for the specific service that is being provided in RUC; and (4) avoiding the creation of perverse incentives, *e.g.*, incentives for suppliers to submit excessively high bids in the DA market to avoid being selected in the IFM and thus become eligible to receive a RUC Availability Payment. The ISO submits that its proposal appropriately balances these objectives and should be approved by the Commission on a conceptual basis.[15]

The October 28 Order suggested that a $250 cap on Availability bids was appropriate because that is the level of the bid cap for Ancillary Services, and RUC is "similar to the procurement of capacity in the ancillary services market." October 28 Order at P.123. The ISO submits that a $150 bid cap on the Availability Payment and a total payment cap of $250 for Availability and energy are just and reasonable for several reasons. First and foremost, a lower bid cap and a total hourly payment cap are appropriate because the ISO is no longer proposing to rescind the Availability Payment if the unit is dispatched for energy. The Commission suggested that rescission of the Availability Payment was inappropriate because the ISO does not rescind the A/S capacity payment if a unit is subsequently dispatched for energy. However, the October 28 Order ignores the important fact that the ISO, under current rules, rescinds the capacity

[15] In addition to balancing the aforementioned objectives, the ISO's revised RUC proposal also represents a comprehensive "compromise" among parties' competing positions on the various elements of RUC compensation. For example, some parties argue for a $250 bid cap on the Availability Payment, others argue for a lower cap. Some parties argue that the Availability Payment should be rescinded if the unit is dispatched for energy, others argue that it should not be rescinded. Some parties favor "netting" the Start-up and Minimum Load costs from other revenues earned by the supplier; suppliers oppose netting. Suppliers also argue that certain other costs such as intrastate transportation costs should be included in Start Up and Minimum Load Costs; although, the Commission rejected such arguments in the October 28 Order.

payment for Replacement Reserves if the Replacement Reserve capacity is subsequently dispatched as energy. Replacement Reserves are more akin to RUC capacity than any other Ancillary Service the ISO provides because the ISO procures Replacement Reserve capacity based, *inter alia*, projected shortfalls in Day-Ahead schedules.[16] *See* ISO Tariff Section 2.5.3.3. Original Sheet No. 63. As a result of the energy crisis, the ISO has not procured Replacement Reserves with the intent that they will be held in reserve pending a "contingency." Rather, the ISO generally has anticipated that it would deploy Replacement Reserves – just like the ISO expects that it will deploy RUC capacity. Consequently, unlike Operating Reserves, there is a very high likelihood that a unit owner awarded RUC capacity will receive both a capacity payment (*i.e.* RUC Availability Payment) and an energy payment. Given this, it is appropriate that the bid cap for RUC Availability Payment be set lower than the bid caps for Ancillary Services. Moreover, it is worth noting that having different bid caps for different capacity services is not a concept unique to the ISO. For instance, PJM has different bid caps for its Ancillary Services[17].

The ISO does not understand why the Commission believes it is appropriate to rescind the capacity payment for Replacement Reserves that are dispatched, but not appropriate to rescind the Availability Payment for

---

[16] Although RUC is somewhat comparable to Replacement Reserve and certainly is more like Replacement Reserve than any other Ancillary Service, for the reasons set forth in the MD02 Filing, Replacement Reserve is not an adequate substitute for RUC. *See* MD02 Filing, Transmittal Letter at 53, n. 116.

[17] In PJM, the bid cap for Regulation capacity is $100/MW and the bid cap for Spinning Reserve is $7/MW.

comparable RUC capacity.[18] Indeed, the ISO believes the rationale that the Commission set forth for rescission of the Replacement Reserve capacity payment supports rescission of the RUC Availability Payment. Specifically, rescinding the Availability Payment for units that that are dispatched removes the incentive for suppliers to submit unreasonably high bids in the DA market (so that the bids will not be accepted) in order to be committed in RUC, thereby earning an Availability Payment (as well as an Energy payment). A similar problem plagued the ISO's Replacement Reserve market (*i.e.*, suppliers were holding back until Real Time so they could receive both a capacity and an energy payment) until the Commission approved Tariff provisions rescinding the capacity payment upon dispatch. In that regard, the Commission ruled that suppliers could receive either a capacity payment or an energy payment but not both. *See San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated By the California Independent System Operator and the California Power Exchange,* 93 FERC ¶ 61,294 at 61,995 (2000). The Commission approved this approach to remove the financial incentive for suppliers to wait until Real-Time to submit bids.

The ISO believes that the best approach to eliminate the incentive for suppliers to avoid the DA market by submitting excessively high bids is to rescind the Availability Payment when a unit is dispatched for energy. However, in light of the Commission's directive in the October 28 Order, the ISO is no longer

---

18 Moreover, in bidding Replacement Reserves, the bidders had to internalize their Start Up and Minimum Load costs among their capacity and energy bids. Under RUC, the Availability bid need not internalize such costs because a unit committed in RUC is kept whole for the SU/ML costs it may incur.

proposing to rescind the RUC Availability Payment. Accordingly, some other mechanism to mitigate market power and provide more appropriate incentives must be implemented. Absent rescission of the Availability Payment, it is imperative that a lower Availability Payment bid cap and a total payment cap of $250/MW for the combined energy and RUC Availability Payment be in place.

The proposed compensation scheme also is fair and appropriate given what RUC is – a one-day energy reliability service. The potential to earn what essentially amounts to a double payment (*i.e.*, being able to bid up to $250 for both energy and availability and receive both payments), is inappropriate given the nature and intent of RUC.

Second, RUC capacity and A/S capacity are very different services. In this regard, it is useful to elaborate on a point mentioned above, *i.e.*, absent a "contingency", the ISO does not expect to dispatch Operating Reserves capacity for energy.[19] Therefore, it is highly unlikely that the supplier of capacity that must be maintained as Operating Reserves will receive both an energy payment and a capacity payment, because it is expected that such capacity will be deployed as energy only following a "contingency."[20] On the other hand, when the ISO commits a unit under RUC, the ISO expects to dispatch that unit for energy because the amount of energy from such unit is necessary to meet the ISO's

---

19 Exceptions may occur in cases where available A/S exceed the minimum A/S requirements due to load forecast errors, errors in estimating the level of firm and non-firm interchanges, or A/S self-provision. The ISO must maintain an Operating Reserve equal to (1) five percent of the Demand (except the Demand covered by firm purchases from outside the ISO Control Area) to be met by Generation from hydroelectric resources, plus seven percent of the Demand (except the Demand covered by firm purchases from outside the ISO Control Area) to be met by Generation from other resources or (2) the largest single contingency, if this is greater. Ancillary Services Requirements Protocol, Section 5, Original Tariff Sheet No. 409.

20 Some Operating Reserve is explicitly marked as "contingency only" by the A/S suppliers so that the ISO cannot dispatch them for energy even in the case of surplus A/S capacity.

load forecast. In other words, unlike Operating Reserves, there is a general expectation that the RUC capacity will be dispatched for energy, thereby making it more likely that the unit owner will earn both a capacity payment and an Availability Payment. Thus, the Availability Payment is essentially an up-front reservation payment for an Energy service; it is not intended as a payment to hold capacity in "reserve." Indeed, RUC units are not required to keep their capacity unloaded. To the contrary, they are required to bid it in the HA and RT markets for dispatch against load appearing in those markets. Because RUC energy will be selected before energy from capacity that must be retained as Operating Reserve,[21] RUC capacity is not like Operating Reserve capacity. Moreover, uninstructed generation from RUC capacity does not cause rescission of the RUC availability payment; whereas, uninstructed generation from Operating Reserves would result in both the rescission of the A/S capacity payment and non-payment of uninstructed RT energy (A/S "No Pay" provision). These facts justifies a lower bid cap and a total payment cap for RUC.

Another consideration that distinguishes the RUC Availability Payment from an A/S capacity payment is that units selected and paid the RUC Availability Payments can (in principle) also submit A/S bids in the HA market, thereby potentially receiving three payments—a RUC Availability Payment, an A/S capacity payment and an energy payment.[22] Units bidding A/S capacity can at most receive an A/S capacity payment and an energy payment (albeit the latter

[21] Under MD02, Operating Reserve capacity is treated as being at the end of the bid curve.

[22] In this situation the RUC capacity would not be able to select "contingency only" status for capacity receiving both the Availability Payment and the A/S capacity payment.

with a low probability). This additional difference between RUC and A/S capacity supports a different compensation scheme for them.

The ISO also is revising its RUC proposal to permit Availability bids to set a locational MCP. This is consistent with the October 28 Order. October 28 Order at P 123. Because the ISO contemplates that there will be instances where the ISO will need to procure RUC capacity to satisfy locational needs that are not accounted for by RMR (e.g., as the result of a DA load forecast error or a short-term situation such as an unexpected outage), some mechanism must be in place to protect against the exercise of local market power. The ISO's proposal accomplishes that goal, while still providing supply resources with adequate compensation in those instances in which their availability bids are mitigated for local market power reasons. A resource whose Availability bid is mitigated can set the availability MCP, and collect a higher Availability MCP than its mitigated bid if the MCP at its location is set by other accepted availability bids. Mitigated Availability bid prices would be based on competitive Availability bid reference levels (*e.g.*, the mean or median of system-wide availability MCPs for the preceding 90 days).

The ISO also proposes to "net" Start Up and Minimum Load Costs from A/S revenues, energy profits earned in the ISO markets (defined as MCP - bid) and RUC Availability Payments. In the October 28 Order, the Commission rejected the ISO's "netting" proposal because, unlike the eastern markets, there was no mechanism in place for suppliers to earn capacity payments that would "balance" the netting of revenues following the RUC process. However, given that the Availability Payment is no longer being rescinded, RUC units will be receiving a capacity payment for the RUC service they provide. Therefore, the rationale for the Commission's decision to reject "netting" in the October 28 Order does not apply. As the ISO has indicated previously, the eastern independent system operators "net" Start Up and Minimum Load Costs. MD02 Filing, Transmittal Letter at 97-98; ISO's September 17, 2003 Answer to Protests at 124-25. It is appropriate to accord the ISO the same treatment as the Eastern independent system operators with respect to "netting" especially now that suppliers in RUC are guaranteed a capacity payment. Failure to require "netting" provides additional incentives for suppliers to bid strategically to avoid commitment in the IFM in order to capture the additional compensation offered in RUC. Specifically, it means that suppliers, having been guaranteed recovery of their Start-Up and Minimum Load costs through RUC are free to participate in ISO markets, retaining all of their profits by selling energy from their capacity at market based rates. This essentially causes consumers to subsidize the suppliers' other out-of-market activity or pay twice for the same energy.

The ISO also is modifying its proposal with respect to Start-Up and Minimum Load Costs compensation. Specifically, the ISO would retain its original proposal to include auxiliary power costs in the Start Up costs to be recovered, and would add intrastate gas transportation and municipal use fees to the Minimum Load Costs to be recovered. Suppliers have been seeking inclusion of these costs in Start Up and Minimum Load costs, and the ISO believes that it is reasonable to allow for the recovery of such costs as legitimate Start-Up and

Minimum Load Costs. The ISO also proposes to use a two-day average for determining gas costs, rather than the monthly average that the ISO initially proposed in its MD02 Filing and which has been in place in California for the past several years. The ISO believes that a two-day average will more closely reflect the actual gas costs being incurred by suppliers under RUC than will use of a monthly average.[23]

Finally, the ISO is proposing a new constraint that will ensure that RUC capacity procured in the DA will not be used to serve incremental exports in the HA. The ISO submits that the additional constraint it is proposing avoids needless complexity and is completely appropriate given that the ISO will be paying suppliers a capacity payment to be available to serve forecasted ISO-Control Area load, and such payment will not be rescinded.[24] Williams and Reliant contend that RUC units should have the ability to export the energy on a

[23] Williams suggests that RUC eligible resources should have the opportunity to submit new bids in the RUC process. Williams at 13. Under the ISO's proposal, suppliers are permitted to submit new Energy bids associated with their RUC capacity, provided such bids do not exceed the level of their bid in the DA market. Given the earlier point that RUC capacity has a high probability of being dispatched for energy in RT, if suppliers were permitted to raise their bids once they have been selected in RUC, they would have no incentive to bid competitively to increase their likelihood of dispatch. Given that suppliers are being guaranteed a non-rescindable Availability Payment, it does not make sense that they should be permitted to increase their Energy bids. Indeed, that would be contrary to the call-option concept which the Commission and suppliers claim RUC is.

[24] Southern California Edison Company ("SCE") suggests that it is possible that suppliers could be paid twice for the same capacity – once under RUC and once under a resource adequacy contract. SCE at 6. SCE suggests that the Availability Payment should be eliminated once a resource adequacy program is in place. The ISO is designing RUC as a stand-alone mechanism that must perform effectively regardless of the ultimate design of all aspects of the resource adequacy program. Moreover, not all resources participating in RUC will have a resource adequacy contract and will still need to be compensated appropriately. To the extent SCE is concerned that supplies will be paid twice for the same capacity, SCE could address the issue in their supplier contracts. As the ISO proposed in item 10 of its modified RUC proposal, any unit pre-designated as a capacity resource under a LSE's resource adequacy plan would not be eligible to receive or set the RUC availability MCP, provided the both resource owner and the LSE agree to this treatment. In addition, the ISO is interested in discussing with stakeholders at the technical conference the possibility of a RUC "self-provision" mechanism which could address SCE's concern.

recallable basis subject to recall in the event the ISO needs to dispatch the energy behind the capacity. Williams Comments at 12; Reliant Comments at 7. The ISO believes that this proposal would add significant complexity to the MD02 design. Currently the ISO does not have a recallable interchange product in the forward market, and did not propose such a product in MD02 because it would introduce an entirely new market to the ISO design, adding cost and complexity in the absence of a demonstrated, compelling need. To illustrate the complexity introduced, note that whether or not the export is intended to be recallable, it can provide counter-flow capacity for import schedules. If the net import tie line schedule on the specific tie is close to the tie transmission limit, once the export is curtailed, the import would also be curtailed availing the ISO of no net energy. Providing for recallable exports would not only increase the complexity of the market design, but it would do so for very little gain.

3. The ISO's Proposed Treatment of Imports In The RUC Process Is Justified And Necessary

It is both appropriate and necessary that the ISO procure energy from imports in the RUC process (as opposed to procuring only capacity). As the Commission is well-aware, the ISO is heavily dependent on imports and cannot, for a substantial share of the operating hours during the year, serve internal load without import supplies. On firm load-shed days during the past four years, internal generation was insufficient to cover high loads. On these load-shed days, the availability of imports was significantly less than on comparable days when no load was shed. At the March 3-5 technical conference, the ISO will be prepared to provide more detailed information demonstrating the ISO's heavy reliance on imports and why the ISO needs to facilitate the participation of imports in RUC.

Given the argument above, the CAISO's proposal to procure energy, not capacity, from imports through the RUC mechanism serves an important market function. It allows the CAISO the opportunity to substitute less expensive energy from imports for more expensive capacity where that opportunity exists by procuring the less expensive import energy and netting it against unscheduled forecast load, thereby lowering the (perfectly inelastic) demand for capacity in the RUC mechanism. It effectively introduces the opportunity for some elasticity of demand for availability in the RUC mechanism. This can only increase competitiveness of the RUC market and the efficiency of the resulting procurement.

In addition to the market function, the ISO's proposal to procure energy from imports, not capacity, is intended to conform better with the scheduling practices in the WECC. In particular, suppliers importing energy need to line up transmission capacity outside of California in the DA time frame. In the WECC region, most units are committed in advance of the next operating day. The ISO's proposal to acquire import supply needed to meet unscheduled but forecasted demand in the day-ahead time frame is consistent with this approach. The ISO's proposal facilitates import participation by accommodating imports in a manner that is consistent with general practices in the West. In particular, the ISO is concerned that if import suppliers only had a commitment from the ISO for capacity, that might not be sufficient incentive for them to acquire the necessary transmission capacity (or might otherwise result in an inefficient use of transmission capacity). Indeed, representatives of importers clearly indicated at the MD02 Technical Conference that procuring capacity is not a practical way to use the transmission system, and importers generally are unwilling to firm up transmission for capacity bids because it too costly. They made it clear that when they bid into the ISO, it is generally for energy not capacity. This supports the ISO's position that the ISO needs to be able to procure energy from importers in the RUC process. Even if a capacity commitment in RUC would be sufficient incentive for an importer to acquire the necessary transmission capacity, it would still not guarantee that the energy would be available for the ISO in Real-Time. To guarantee Real-Time energy availability from such imports, the capacity commitment from the ISO would have to be secured with a binding obligation on the supplier to have the associated energy available for the ISO in Real-Time at a pre-specified bid price.

4. Ruc Procurement Target And Potential Ruc Self-Provision

The California Department of Water Resources, State Water Project ("SWP") argues that market participants should have the ability to opt out of RUC and assume full responsibility for their loads. SWP at 4. Stated differently, such market participants should be permitted to "self-provide" their RUC capacity. Other parties argued that the ISO's DA RUC procurement and cost allocation to

DA under-scheduled load would pre-empt LSEs' ability to shop for cheaper energy after the close of the DA market.

The ISO recognizes these concerns, but must ensure that it can fulfill its responsibility for reliable RT operation by identifying and procuring capacity it expects to need in RT and may only be available in DA. At the January 28-29 technical conference, some parties suggested the idea, in the context of A/S self-provision, of SCs committing on a DA basis to a quantity of A/S that they would self-provide in the HA market. The ISO suggests that a similar idea may be applicable to DA RUC. Perhaps there is a way for LSEs to make a DA commitment to schedule specific quantities of additional supply in HA, and to support this commitment by identifying specific resources from which they can supply capacity in the event they fail to procure the committed energy. Based on this "self-provided" RUC capacity, the ISO might be able to reduce its DA RUC procurement target (and the corresponding cost allocation to the self-providing LSEs). This concept could also address the concern about double payment to RUC capacity (*i.e.*, an Availability Payment plus a resource adequacy contract) that was raised in some parties' comments, because the capacity so identified would not receive a RUC Availability Payment.

Although the ISO does not yet have a detailed proposal for how to implement RUC self-provision, the ISO offers some initial thoughts on the matter and would like to discuss this topic further at the technical conference. The ISO expects that RUC self-provision would entail the LSE specifying, at the time of submitting its DA schedule and bid information, additional capacity (*i.e.*, specific resources and MW quantities) that it has not scheduled, but is available for the next day. For example, such capacity might include capacity the LSE has obtained under contract to meet its resource adequacy obligation, which allow the LSE the flexibility to shop for cheaper energy after the DA market without risking a RT shortage if no cheaper energy is found. It would be appropriate for the LSE who wants to under-schedule in the DA to identify such resources to the ISO in the DA so that the ISO would not "RUC" additional capacity – and the LSE would not be charged – for this quantity of under-scheduling. Verification procedures would be needed to ensure that capacity slated by the LSEs to show up in the HA market is flagged properly so that it is not selected by the ISO in DA RUC to compensate for other LSEs' under-scheduled load, and to enable the ISO to ensure that its energy, if needed, would be deliverable without causing congestion in real time.

The Sacramento Municipal Utility District ("SMUD") requests that the ISO clarify whether the ISO will procure RUC on behalf of, or allocate RUC costs to, entities like SMUD that operate their own control areas. SMUD Comments at 16. SMUD notes that metered subsystems ("MSS") that cover their own load will not be assessed any RUC charges. SMUD alleges that it is comparable to a MSS because SMUD takes full responsibility for its load, and will essentially self-provide RUC resources. The ISO clarifies that RUC is intended to satisfy ISO control area load only, so RUC capacity would not be procured for loads in other control areas.

C. Constrained Output Generators

In its MD02 Filing, the ISO stated that it was inappropriate for Constrained Output Generators ("COG") to set the energy price in the DA market because (1) it would essentially involve acceptance of an infeasible schedule with the knowledge that such schedule would have to be adjusted in Real-Time, and (2) energy would be priced based on the COG, although the actual marginal price for determining congestion charges would be the price of the generator that was decreased to make room for the COG. In its October 28 Order, the Commission noted that each of the Eastern independent system operators has developed mechanisms that allow non-dispatchable units to set the clearing price in the DA market. October 28 Order at P 89. Accordingly, the Commission directed the ISO to

> review its approach to setting prices in the forward market and develop a pricing mechanism for Constrained Output Generators that is consistent with its approach to real-time pricing (*i.e.*, a constrained output generator can set the market clearing price for those dispatch in intervals in which any portion of its output is needed to serve real-time load) and promotes the convergence of prices in the forward and real-time markets.

Id. The January 21 Notice raised the following questions regarding COGs for consideration at the MD02 technical conference: (1) when is it appropriate for COGs to set the market clearing price, and (2) whether and why different pricing rules between the Day-Ahead and Real-Time markets may be appropriate. At the MD02 Technical Conference, Commission Staff also requested that the ISO identify the number, size and location of all such Constrained Output Generators, indicating whether the unit's output is constrained by transmission.

Based on the discussions at the MD02 Technical Conference and the comments filed by the parties,[25] the ISO is proposing to revise its treatment of COGs. The ISO's revised proposal which the ISO wishes to discuss with stakeholders at the March 3-5 technical conference is as follows:

1. COGs eligible to set prices, both in the integrated forward market ("IFM") and in Real-Time would be CTs that can only run at full output. This definition is consistent with the definition of Constrained Output Generators adopted by the Commission in its order on the ISO's Tariff Amendment No. 54.[26] *See California Independent System Operator Corporation*, 105 FERC ¶ 61,091 at P70 (2003).

   In response to Commission Staff's request for data on these units, the ISO can report that the population in question consists of 21 generating units, ranging in size up to roughly 60 MW and totaling 831 MW of capacity in all. Only two of these units has had its output reduced due to transmission constraints over the past 12 months, and, in these cases, the number of transmission-constrained hours was less than 100 for each of the two units.

2. The specification of the circumstances in which COG may set prices is as follows:

   a. Eligibility to set price in any settlement interval would depend on some portion of the unit's output being needed in merit order to serve load. In other words, if the unit is modeled as fully flexible to operate over its entire capacity range, it would receive a non-zero merit-order dispatch to clear the market.

   b. If the unit was needed in accordance with criterion 2.a in a previous settlement interval, and is still operating due to a minimum-run-time constraint, but none of its energy is needed

---

25 For example, Williams and Reliant argued that the ISO should permit COGs to set the price in instances where the unit is required to serve load. Reliant Comments at 13; Williams Comments at 17.

26 The Commission stated that COGs "are generating resources that cannot easily or economically change load levels and are typically restricted to generating at their full capacity for their unit-specific minimum run time. 105 FERC ¶ 61,091 at P 70.

in merit order in the current interval, the unit would not be eligible to set price in the current interval.

This criterion is consistent with the direction given in the October 28 Order as quoted above.

3. The ISO is still evaluating some alternative ways to implement this proposal in the IFM design. One approach under consideration is the following:

   a. In the IFM dispatch run, all operating constraints of COG units would be observed. As a result of this run, a COG unit that it is needed per criterion 2.a would be dispatched at its P-max. At the same time, some cheaper energy may not be fully dispatched in this run due to the operating constraint on the COG unit.

   b. In the IFM pricing run following the dispatch run, all units would be set initially at their dispatch levels from the previous run. Those units that are eligible to set prices, including the COG units dispatched in the previous run, would be treated as flexible within a specified, constant-price operating interval of their dispatch levels.[27] Thus, this run produces prices that are based only on the resources eligible to set prices.

The ISO submits that its proposal is consistent with the Commission's guidance in the October 28 Order and compatible with the overall MD02 design. The ISO's proposal is consistent with the NYISO's treatment of fixed block generation, *i.e.*, fixed block generation is permitted to set the price when needed to meet load or avoid the operation of higher-cost units. *See New York Independent System Operator, Inc.* 100 FERC ¶ 61,182 (2002).

The comments filed on February 17 indicate that some parties oppose allowing COG units to set prices because (1) the resulting prices are not true

27 The optimal length of the interval around the dispatch level of the previous run for flexible units needs to be determined empirically in the testing phase of the IFM software. The larger the interval is, the greater the inconsistency between dispatch and pricing will be and the greater the chance will be to have the appropriate eligible units set prices in each interval.

marginal prices in the theoretical sense, and (2) the resulting forward prices will be somewhat higher when COG units are allowed to be price setters than when they are not.[28] While the ISO recognizes these concerns, the ISO submits that the revised approach proposed herein is appropriate because it reflects a reasonable balance between several conflicting objectives. As the ISO explained in its January 14 clarification, the conflicting objectives are as follows:

> Ultimately the problem derives from the fact that we are trying to satisfy several objectives that are not fully mutually consistent. First, the CAISO wants LMPs to express the cost of serving the next MW of load at the location, according to the formal definition of marginal prices. Second, the CAISO wants the prices to reflect such costs in a realistic manner, by incorporating all the generation that must be dispatched to serve the load. When lumpy generation is needed to serve load, these two objectives come into conflict, because the mathematical optimization requires marginal generators to be continuously dispatchable above and below their optimal operating points, and hence will exclude lumpy generation from setting prices.[29] Third, the CAISO wants settlement for CRRs (in the day-ahead market) to be consistent with the actual pattern of congestion. If the CAISO allows lumpy generation to set day-ahead prices we compromise this objective. Fourth, the CAISO wants to send meaningful real-time price signals to encourage forward scheduling of load and real-time demand response. This would argue for allowing lumpy generation to set prices in real-time (as the CAISO proposed and the Commission approved for Phase 1B). Fifth, the CAISO does not want to create impediments to convergence in prices between forward and real-time markets.

The modified proposal presented here achieves the objective of creating prices that realistically reflect the cost of serving load in each interval in a manner that is consistent across the forward and real-time markets. This proposal also resolves some earlier concerns by not establishing infeasible forward generation

---

28 SCE Comments at 9.

29 A way around this could have been to ignore the lumpiness of the resource and dispatch it in the forward market as if it were fully flexible. But this would result in accepting an infeasible resource schedule, which would compromise one of the fundamental objectives of the MD02 effort, *i.e.*, to establish feasible schedules in the forward markets.

schedules and by reducing the possibility of distorting the CRR settlement by setting nodal price differences that are opposite to the direction of congestion.[30] The ISO's proposal achieves a just and reasonable balance of these objectives and should be approved by the Commission.

D. Ancillary Services

In its MD02 Filing, the ISO indicated that it was proposing to incorporate A/S procurement in the DA and HA markets and would select resources using an integrated approach that co-optimizes Energy and A/S procurement costs. The ISO noted that it intended to satisfy the bulk of its A/S procurement requirements in the DA timeframe. However, the ISO stated that it

> may defer satisfying all of its projected Day-Ahead A/S requirements until the Hour-Ahead market if the CAISO believes that its load forecast (and, thus, A/S requirement) is likely to change. This will allow the CAISO to minimize the risk of over-procuring A/S. Deferment of A/S procurement also allows the CAISO to adjust Day-Ahead A/S procurement to account for SC self-provision of A/S in the Hour-Ahead market. Finally, the CAISO may defer procuring A/S if it anticipates that the price of A/S may be lower in the Hour-Ahead market. This is consistent with the CAISO's obligation to procure A/S at least cost. The CAISO will not defer Hour-Ahead A/S procurement to Real-Time unless there are insufficient A/S bids in the Hour-Ahead market.

MD02 Filing, Transmittal Letter at 83. Moreover, the CAISO explained

---

[30] In its Clarification of CAISO Market Design Issues filed on January 14, 2004 ("January 14 Clarification"), the ISO stated expressed a concern that Constrained Output Generators setting the price in the DA would result in CRR settlements in the opposite direction of congestion. The instant "tailored" proposal does not create significant concerns in this regard. At the MD02 technical conference, a representative of Reliant stated that this would occur only in instances where the Constrained Output Generator is located in a generation pocket where transmission is insufficient to "export" all of the power to load. He noted that in PJM, such generators tend to be near load, not in constrained generation pockets. As shown in Attachment A, in the ISO Control Area there are a significant number of Constrained Output Generators located in generation pockets. Thus, the perverse CRR settlement results identified in the ISO's January 14 Clarification will occur regularly if Constrained Output Generators are permitted to set the clearing price in the DA market.

that:

> The ISO may defer satisfying its total A/S obligations until the Hour Ahead IFM. As specified in Operating Procedure M-402, sections 1.1 and 2.1.4 (posted on the ISO website), the ISO may defer satisfying all of its projected Day Ahead A/S requirements until the Hour Ahead IFM if, among other reasons, the ISO believes that its load forecast (and thus the A/S requirement) is likely to change. In this way, the ISO can minimize the risk of over-procuring A/S. Deferment also allows the ISO to adjust Day Ahead A/S procurement to account for SC self-provision of A/S in the Hour Ahead market. The ISO may also defer purchasing A/S if it anticipates that the price of A/S may be lower in Hour Ahead. This provision is consistent with the ISO's obligation to procure A/S at least cost.

MD02 Filing, Attachment A at ¶ 55. The ISO noted that this practice of "economic deferment" was consistent with its existing practice, whereby the ISO historically has procured moist of its A/S requirements in the DA timeframe.[31]

In the October 28 Order, the Commission expressed some concern that price divergence between the DA and HA markets might occur under the ISO's proposal because the ISO would be the only purchaser of A/S in the HA market and could have the power to suppress prices. October 28 Order at P 83. The Commission also expressed concern that the ISO might be speculating in the market. Although the Commission ultimately allowed the ISO the flexibility to procure a portion of its A/S requirements in the HA market, the Commission also

---

[31] Under the ISO's current market design, the A/S markets are conducted sequentially, following the running of the congestion management market. Economic deferment is relatively straightforward because there is an explicit supply curve for each Ancillary Service from which the ISO can calculate the cost of procuring any particular quantity of A/S in the DA market. In the context of the proposed IFM, there would be no such explicit supply curves for A/S. Economic deferment would be performed in the DA IFM by the ISO submitting a price-elastic demand curve for each A/S instead of a specific MW procurement target (equivalent to an inelastic demand curve). Of course, in the HA market the ISO would be required to complete its required A/S procurement so its HA demands would be fixed quantities. This last point is discussed further below.

ruled that suppliers should be allowed the same flexibility to buy-back A/S in the HA.[32] *Id.* The January 21 Notice raised the following questions for consideration at the MD02 Technical Conference: (1) to what extent should the ISO have well-defined, transparent A/S procurement rules; (2) how much flexibility the ISO should have in determining when to purchase needed A/S (and what the impacts are); (3) whether market participants should have the opportunity to buy-back their A/S position in the H/A market; and (4) what impact the HA buy-back of A/S would have on markets and system operators.

In their comments, several suppliers expressed concern about the ISO's proposal to defer A/S purchases to benefit from potentially lower HA prices. Williams Comments at 15. Some parties suggested that the ISO consider establishing a notification procedure in the DA market for LSEs to notify the ISO of the amount of self-supply A/S that will be available in the Hour-Ahead. Williams at 16. Other parties recognized that reasonable limits on the ISO's purchase of A/S in the Hour-Ahead might be appropriate. SMUD Comments at 14-16. Several suppliers argued that it may be appropriate for the ISO to procure varied amounts of A/S in the Day-Ahead and Hour-Ahead, so long as suppliers have the same flexibility to buy-back A/S. Reliant Comments at 10-12; Mirant Comments at 7; Duke Comments at 3. The CPUC expressed concerns about A/S buy-back by suppliers (CPUC Comments at 6), and SCE argued that suppliers should not be permitted to buy-back A/S. SCE Comments at 8.

---

32 The Commission also directed the ISO's Department of Market Analysis to monitor the convergence/divergence of A/S prices in the DA and HA and report to the Commission on a monthly basis following implementation of the DA market.

Based on the discussion at the MD02 Technical Conference and subsequent internal discussions, the ISO is proposing to revise its A/S procurement proposal as follows:

1. Under MD02, the ISO would not continue the currently approved practice of economic or price-based deferment of A/S procurement from DA to HA. The ISO has some concerns about this concession, however, due to the fact that its demand for A/S is determined by Western Electricity Coordinating Council ("WECC") reliability criteria and is therefore inelastic. This issue is discussed further below.

2. The ISO would set its DA procurement target at 100% of its estimated A/S requirements, based on its DA load forecast and allowing for A/S self provision. Because this approach is based on an estimation process, the ISO still may be required to procure some additional A/S in HA.

3. That is, SCs who wish to defer some self-provision of A/S from DA to HA and avoid having the ISO procure A/S for their deferred quantities, would have to commit to a specific quantity of HA self provision in the DA scheduling time frame.[33] Such commitment would be binding, in the sense that failure to deliver the committed capacity would result in a penalty, such as a per-MW charge on the shortfall.[34]

4. The ISO would procure additional A/S in the HA only when needed to supplement DA procurement due to unscheduled outages, changes in estimated A/S requirements (for example, due to revised load forecast or changes in the expected hydro-thermal supply mix), or possibly failure of the SCs to meet their DA commitments to self provide HA A/S capacity.

5. Sale of A/S in DA would be viewed as a binding commitment. HA buy-back by suppliers of DA A/S capacity would be allowed only in the event of

[33] Even with such commitments, the ISO would still face some risk of under-procurement of A/S. Therefore, it may be appropriate to set a limit on the amount of deferred self-provision a SC would be able to declare in DA. Moreover, ongoing discussions at NERC regarding A/S adequacy may lead to a new requirement to procure A/S fully in the DA time frame, which would make the issue of deferred self-provision moot.

[34] Note that the risk to the SC of A/S over-procurement by the ISO is not as great as it may seem at first glance. The SC's total A/S obligation for settlement purposes is based on the SC's final metered real-time consumption. If the SC totally meets that obligation through self-provision there is no charge for A/S for that settlement hour, irrespective of whether the self-provision was in DA or HA. If the ISO over-procures A/S as a result of HA self-provision – *i.e.*, the total MW of A/S procured by the ISO are greater than the total MW A/S obligations of all SCs, after crediting self-provision – the cost of the excess MW procured by the ISO is distributed uniformly to all ISO control area loads via the neutrality adjustment, not charged specifically to SCs that self-provide in HA.

unplanned outages that render the originally sold capacity unavailable. In this instance, the seller would buy back its DA A/S capacity at the higher of the DA or HA price.

The ISO's revised proposal addresses the concerns raised in the October 28 Order, yet will still ensure that the ISO has sufficient flexibility to address reliability concerns. Because the Commission's October 2003 Order explicitly linked HA buy-back to the ISO's proposed deferment of A/S purchases for economic reasons, such buy-back should not be permitted now that the ISO will no longer be deferring A/S purchases for economic reasons.

However, as noted above the ISO has some concerns about completely foregoing the ability to defer a portion of its A/S procurement from DA to HA for economic reasons. This concern is based on the fundamental fact that the ISO's demands for A/S are set by external reliability criteria and, as such, are inelastic. The Commission's October 28 Order seems to have overlooked this fact in linking supplier buy-back of A/S with ISO economic deferment of A/S procurement. This linkage is not appropriate because the ISO's A/S demands are inelastic. In particular, the idea that the ISO is in a position to exercise "buyer" market power in the A/S markets is simply not correct. To the contrary, the inelastic demand for A/S means that the ISO is vulnerable to the exercise of supplier market power in the A/S markets.

In the same vein, contentions by certain parties that the ISO is a monopsony buyer in the A/S markets are misplaced. The concept of monopsony does not apply in the context of A/S procurement. Monopsony applies when sellers have no choice but to sell into a market where there is only one buyer.[35] In the case of generating capacity and energy, sellers have numerous ways to sell their capacity and/or their energy without being captive to the ISO's A/S markets. Suppliers can sell capacity bilaterally for Scheduling Coordinators to self-provide A/S, or to other control areas. They can sell their energy bilaterally, to buyers inside or outside the ISO Control Area. Moreover, under the FOO, there would be no "must offer" obligation on suppliers with respect to the IFM, which includes the A/S markets.[36] As such, the ISO has no ability to force sellers to sell A/S capacity at all, let alone force them to accept a price at which they are unwilling to sell, because the sellers have other options.

Given the context described above, unrestricted discretion on the part of sellers of DA A/S capacity to buy back in HA would be inappropriate, even if the ISO were to engage in economic deferment of A/S procurement from DA to HA. Although the CAISO has an obligation to procure A/S at least cost, the quantities of A/S it must procure are set by the WECC (*i.e.*, "MORC") and the prices are

---

[35] The typical textbook example of monopsony is a labor market in which there is a single large employer in a particular town. Labor is essentially captive to this employer because there are no other opportunities locally, and it is extremely costly for workers to relocate to seek employment elsewhere. Moreover, the employer's demand for labor is flexible in the sense that it can adjust its operations, including the number of employees it hires, so as to maximize its profits. Under these circumstances the employer can procure its needed labor at wages below those that would occur in a competitive market. See, for example, Hal Varian, Intermediate Microeconomics, W. W. Norton, 1987, pp. 439-440. Note that the crucial conditions for this outcome – *i.e.*, elastic demand on the part of the buyer, and the lack of other opportunities for the seller – do not apply in the case of the ISO's A/S markets.

[36] Under the MD02 proposal, resources that bid into the DA or HA IFM are considered for A/S only if they explicitly submit bids for A/S capacity. The ISO is not free to optimize between Energy and A/S using all resources that bid into the IFM. One question that may merit further discussion at the technical conference is whether all resources bidding into the IFM should be considered in the joint optimization of Energy and A/S. A more limited version of this question is whether all FOO Resources that bid into the IFM should automatically be considered in the joint optimization. Such a provision could deepen the A/S markets and reduce opportunities for withholding from those markets.

determined in the A/S markets by suppliers' bids. Within these constraints, the CAISO optimally procures A/S to satisfy its Control Area Operator responsibilities and its obligations as the provider of last resort using the only flexibility it has to minimize total costs, namely, the ability to defer to the Hour-Ahead market a portion of its total A/S requirements.[37] Thus, the ISO ultimately is subject to an inelastic demand curve because its A/S requirement is based on forecasted load in accordance with regional reliability criteria. If the ISO defers any A/S procurement from the DA, it will then be obligated to fully make up the remainder of its A/S requirement in the HA market, thereby subjecting the ISO to sellers' market power rather than being in a position itself to exercise HA market power. Thus, the deferment of A/S carries some risk for the ISO. Allowing sellers of A/S in the DA to participate as buyers of A/S in HA will exacerbate this risk and increase the potential for sellers to exercise market power.

With respect to the issue of price convergence raised in the Commission's October 28 Order, there are two countervailing forces that will move prices towards convergence: (1) as noted above, any DA deferment by the ISO results in inelastic demand in HA; and (2) sellers are free to modify their offered quantities and prices for A/S in HA. Because the sellers can modify their offers, the ISO has both reliability and cost incentives to minimize A/S deferment to HA.

Perhaps the Commission's concern is that the ISO may want to minimize the overall cost of A/S by deferring part of the requirement to HA even if it results

---

[37] *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs., Regs. Jan. 1991-June 1996, Regs. Preambles ¶ 31,036 (1996), at 31,715-16 ("Order No. 888").

in a higher HA price, because the quantity will be lower so the overall costs (DA plus HA) would be lower than purchasing the full requirement in DA. If this is indeed the basis of the Commission's concern about price divergence, then unrestricted A/S seller buy-back would only increase the divergence by raising the hour-ahead price further.

As a result of these considerations, the ISO believes that it is risky from a procurement cost perspective to completely forego the capability of deferring a portion of A/S procurement to the HA market, because the ISO's demand for A/S is ultimately inelastic. At the same time, it is risky from a reliability perspective to engage in such deferment except to a very limited extent, because there is no guarantee that sufficient A/S capacity will be offered in the HA to cover the deferred amount. For the sake of moving this issue forward, the ISO proposes to forego economic deferment, with the caveat that this may expose the ISO to withholding of supply from the DA A/S market. If experience shows this to be a problem, the ISO will want to reconsider its ability to optimize the procurement between successive markets, or to require all participants in the IFM to be considered in the simultaneous optimization of Energy and A/S. Of course, the pending NERC ruling referenced earlier may make this issue moot.

E. Marginal Losses

The ISO proposed to incorporate marginal losses in the Locational Marginal Prices ("LMPs") calculated in the IFM. Thus, these LMPs would reflect the marginal cost of serving the next MW of load at each location, including the costs of congestion and losses incurred in delivering energy to that location.

Moreover, this approach means that losses are paid for by loads through the settlement for withdrawing energy from the grid. Recognizing that this approach would result in over-collection of loss revenues from loads, the ISO proposed to "rebate" these costs back to loads by adding any over-collection of losses to the CRR Balancing Account. In the October 28 Order, the Commission found (1) the ISO's proposal to reflect marginal losses in its calculation of LMPs to be appropriate, and (2) the ISO's proposal to add over-collection of losses to the CRR Balancing Account (and its method of allocating the surplus revenues) to be reasonable. October 28 Order at PP 77-78. The January 21 Notice raised the following questions for consideration at the MD02 Technical Conference: (1) How the excess revenues created through marginal loss pricing can be returned to the appropriate participants without distorting efficient price signals; (2) how entities that self-provide losses should be treated; and (3) discussion of alternative proposals, including that presented by FPL Energy, LLC.

No party appears to disagree with using marginal losses for purposes of determining LMPs. The primary issue is how to redistribute any over-collected loss revenues. In its July 22 MD02 Filing, the ISO identified the following benefits associated with including excess revenues in the CRR Balancing Account: (1) it would make CRRs more valuable because it would increase the possibility that CRR holders would receive full payment on their CRRs over the course of the year; (2) the proposed approach was easier to implement than other options because the ISO would not have to keep track of locations where loss revenues are over-collected; and (3) if there are surplus funds in the CRR Balancing

Account (after CRR holders are paid their entitlement at the time of the yearly clearing), such funds will ultimately flow back to loads by being paid to Participating Transmission Owners to reduce their Transmission Access Charge. The CPUC, and SCE and Sempra support the ISO's proposal for allocating over-collected loss revenues. CPUC Comments at 6; SCE Comments at 9-11; Sempra Comments at 2-4.

At the MD02 Technical Conference, certain suppliers seemed to suggest that excess losses should be returned to suppliers. They believe that resources located far from loads will suffer high loss factors, which will consequently force them to lower their bids in order to be competitive with similar units located closer to loads. These claims lack merit because this effect merely reflects the reality of the cost to deliver the output of such units to load, and ought to be reflected in the costs of dispatch. Resource owners should take such factors into account when they decide where to locate and how to set their prices. If ISO rebates loss revenues to such units, it may skew accurate locational price signals. This is not an optimal result, especially if it requires extensive (and expensive) transmission upgrades.

The suppliers' argument also is based on a crucial misunderstanding of the Proposal. Their argument seems to be based on a belief that suppliers will pay loss charges under MD02 and, therefore, should be entitled to a share of the "rebated" loss revenues. Although it is true that today the methodology of Generation Meter Multipliers (GMMs) does assess loss charges to suppliers, under LMP the cost of losses will be paid by loads. In that regard, when the IFM calculates nodal prices, each nodal price will reflect the marginal cost of serving an additional MWh of load at that location, including the effects of Congestion and losses to deliver the supply to the load. Thus, the cost of losses will be included in the settlement charges to load. Therefore, it is appropriate to refund the over-collected revenues to loads, not to suppliers.

Once it is understood why it is appropriate to refund the loss revenues to loads rather than suppliers, the use of the CRR balancing account as the means to do this should be less of an issue. The CAISO agrees that it may be more precise to create a separate balancing account for losses, but the required settlement system would be more complex and costly. Moreover, using the CRR account should achieve a very similar result. The reason for this is that any balancing account surplus paid to the Participating TO becomes an offset to the Transmission Access Charge which is paid by all load on a per-MWh basis. While there may be different distributional impacts from such an approach, such impacts would not have a material impact on the locational price signal to load under a load aggregation pricing scheme.

FPL Energy offered a conceptual proposal for a market mechanism that would be operated by the ISO, whereby buyers and sellers of energy would voluntarily trade losses and thus re-allocate some of the loss over-collection. The concept is fairly complex, and FPL's representative at the MD02 Technical Conference acknowledged that it is still a work in progress, and not all the details have been worked out. FPL's representative further acknowledged that if all parties were to trade in this market, the ISO could often be revenue insufficient. Alternatively, if no one were to trade in the market, the ISO would need to have some means to allocate excess loss revenues. Therefore, although the ISO would not dismiss this proposal as potentially having value at some point in the future, the ISO does not believe it would be prudent to incorporate it into the MD02 design at the present time. Even if it were a fully developed proposal and could be demonstrated to be theoretically sound, practically workable, and an unambiguous enhancement to market efficiency, it would still require the ISO to incorporate an additional entirely new market, with the associated bidding and settlement functionalities, into its MD02 design and implementation plan when there is no significant problem to be solved by doing so.

The Bay Area Municipal Transmission Group ("BAMx") supported by Silicon Valley Power, et al., believe that loss over-collections should be allocated in proportion to the difference between marginal losses and average losses to loads that have been overcharged, and refunds of marginal losses over-collections should not be tied to the holding of CRRs. BAMx Comments at 6. BAMx claims that this approach more effectively tracks cost causation because crediting over-collections to CRR holders bears no relationship to the parties that have been over-charged. *Id.*

In the ISO's September 17, 2003 Answer to Protests (p. 59), the ISO acknowledged that a separate tracking and refund process for losses would be more accurate than the proposed use of the CRR Balancing account. At the same time, it would add significant complexity to the settlement procedures and systems. The ISO's proposal offers a reasonable, cost-effective approximation, in view of the fact that excess revenues in the CRR Balancing Account flow back to loads through a reduction of the Transmission Access Charge.

SMUD alleges that the ISO's proposal (1) results in double collection of losses from existing transmission contract ("ETC") holders, and (2) does not satisfactorily accommodate the self provision of losses.[38] The ETC-related issues raised by SMUD are a matter for the stakeholder process to be convened to address settlements issues associated with ETC schedules. In its January 14 Clarification, the ISO indicated how its marginal loss proposal accommodates the self-provision of losses. SMUD has not raised any arguments demonstrating that such proposal is unjust and unreasonable.

F. SIMPLIFYING THE HOUR AHEAD MARKET

In discussions at the MD02 Technical Conference the ISO and other parties noted several instances where having a fully-functional HA settlement market, including all the features of the DA market, creates design challenges and complexities. Therefore, the ISO requested that the parties (1) comment in their filings on the business and operational needs they believe are served by having such an HA market, (2) identify what specific elements of that market are

---

[38] SMUD indicates that it would not object to refunding excess loss revenues to the CRR Balancing Account provided that CRRs are allocated to any entity that contributes materially to the embedded cost of the transmission system, not solely to those entities within the ISO Control Area. As the ISO indicated in its September 17, 2003 Answer to Protests (pp. 98-99) in this proceeding, to the extent the Commission finds that CRRs should be allocated to load located outside of the ISO Control Area, the ISO would work with stakeholders to address the issue. The ISO again states for the record that all customers paying a wheeling charge should not automatically receive CRRs. Rather, consistent with Commission precedent, only parties taking long-term firm transmission service should receive CRRs. *See New England Power Pool, et al,* 100 FERC ¶ 61,287 at P 85 The ISO indicated that it might be appropriate for parties that pay the wheeling charge on a daily basis to receive CRRs. However, to the extent a party does not pay wheeling charges every day, it should not be entitled to CRRs. For example, a party that only sporadically uses the transmission system should not be entitled to CRRs because that party is not making a significant contribution to embedded costs equal to that of native load customers that use the grid every day.

most essential to meet their needs, and (3) consider how their needs might be met with a reduced HA market design.

The idea of simplifying or even eliminating the HA market was previously raised in the context of the Stakeholder Working Groups in fall of 2002. At that time, there seemed to be virtually unanimous demand to retain the HA market. There was some limited discussion (in the IFM Working Group) of the business and operational needs for the HA market, but given the universal demand to retain the HA market and the numerous other issues on which work was required, the group did not seriously consider whether and how the HA market might be simplified and still satisfy parties' needs. The ISO would now like to explore this possibility in earnest at the March 3-5 Technical Conference.

At present, the ISO does not have a specific proposal for how to simplify the HA market, but can offer some thoughts to stimulate the discussion. As noted, there are several design challenges raised by the HA market that have arisen within the limited scope of the present technical conference process. For example, there is the question of how to prevent DA RUC capacity from selling energy for export in the HA market, and the issue of whether the ISO should be able to defer some DA A/S procurement to the HA market. As the ISO continues to develop the implementation details of MD02 and discusses them with the vendors, it becomes clear that the HA market will increase the cost of MD02 in a non-trivial manner (the ISO is currently working on some estimates). For example, the HA settlement creates data management requirements fully equal to the requirements of the DA settlement.

Another potential benefit of simplifying the HA market is that the ISO may be able to move its closing time closer to Real Time. During the Fall 2002 Working Group process, parties expressed considerable interest in having the HA market close at T-60 rather than T-120. The ISO's earliest proposals on MD02 tried to accomplish this but, as the ISO examined the sequence of iterations the HA market would have to perform and the complexity of each, it became apparent that T-60 would be unattainable. If there is a way to reduce the HA market to its bare bones, *i.e.*, the minimal functionality to satisfy most of parties' business and operational needs, then moving the HA market closer to Real Time can be on the table again.

In thinking about how the HA market might be simplified, the ISO would like parties to consider the following questions and be prepared to discuss them at the March 3-5 Technical Conference:

1. Could the ISO limit HA submissions to self-schedules of incremental changes to parties' final DA schedules, *e.g.*, new bilateral transactions that were executed after the close of the DA market, or reductions in scheduled demand and supply due to reductions in the load forecast? In effect, could we do without an HA energy market?

2. Could the ISO limit the HA market to performing congestion management on these submitted self-schedule changes? If so, in the absence of energy bids what might be the basis of congestion adjustment (*e.g.*, effectiveness)?

3. Could the ISO eliminate HA settlement? For example, could the ISO issue RT pre-dispatch instructions based on schedule changes found to be feasible in the HA congestion run, so as to enable these changes to avoid RT deviation penalties, but otherwise settle all deviations between final DA and RT at RT prices?

4. The eastern ISOs all have two-settlement systems consisting of Day Ahead and Real Time settlement markets only. Are there any particular features of the California markets that would make the two-settlement approach inadequate?

The ISO believes that simplification of the HA market offers potential benefits to all ISO participants, and looks forward to this discussion at the upcoming technical conference.

III. CONCLUSION

Wherefore for the foregoing reasons, the ISO requests that the Commission act on the ISO's Revised Comprehensive Market Design Proposal in a manner consistent with the discussion herein.

Respectfully submitted,

Anthony J. Ivancovich
California Independent System
Operator Corporation
Senior Regulatory Counsel
151 Blue Ravine Road
Folsom, California 95630
(916) 608-7135

Filed: February 24, 2004

ATTACHMENT A

Attachment A

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION'S PROPOSED MODIFICATIONS TO ITS REVISED COMPREHENSIVE MARKET DESIGN PROPOSAL FOR DISCUSSION AT THE MARCH 3-5, 2004 TECHNICAL CONFERENCE

DOCKET NO. ER02-1656
FEBRUARY 24, 2004

I. PROPOSED REVISIONS TO RESIDUAL UNIT COMMITMENT PROPOSAL

1. The bid cap on the Availability Payment will be $150. (The ISO originally proposed a $100 cap and FERC approved a $250 cap in its October 28 Order.)

2. The Availability Payment will be paid on a locational MCP basis. The ISO has not yet fully developed the details of how this would operate, but will be prepared to provide further details for discussion at the March 3-5 technical conference. It is important to note that payment of a locational MCP creates a need for local market power mitigation with respect to RUC capacity (*see infra* for proposal on this issue).

3. The Availability Payment will not be rescinded if a unit is dispatched in the energy markets subsequent to the RUC process (for the same operating hour). (The ISO originally proposed that 100% of the "Availability Payment" would be rescinded if the unit was dispatched in the energy market subsequent to RUC. The Commission ruled that no portion of the "Availability Payment" should be rescinded.)

4. The combined Availability Payment received in RUC and Energy MCP received in energy markets subsequent to RUC for any hour cannot exceed $250. This is necessary to avoid potential economic withholding from the DA IFM. Specifically, this measure is necessary to avoid potential disincentives against supplier participation in the DA market and preferential participation in the RT market. Without such a measure, the Availability payment would effectively raise the RT price cap to $400 (the sum of the Availability Payment and real-time energy bid caps under the ISO's proposal). (This is a new provision.)

5. The portion of a unit's output that is mitigated in the pre-IFM run for local market power in the Energy market and does not clear the IFM, will be preserved in RUC (*i.e.*, slated as RUC capacity) and

will be eligible to receive a RUC Availability Payment in addition to the Energy payment that it receives in the market (hour-ahead or real-time) where its Energy is eventually scheduled or dispatched. However, because of its local market power, the unit's RUC Availability bid will be subject to mitigation, *i.e.*, it will be set at the lower of the unit's Availability bid price or a mitigated reference level. The unit can, however, collect a higher Availability Payment MCP (LMP) that may be set at its location by other accepted Availability bids. Mitigated Availability bid prices could be based on competitive Availability bid reference levels, *e.g.*, the mean or median of system-wide Availability MCPs for the preceding 90 days. (This is a new provision).

6. Recovery of Start-Up and Minimum Load Costs shall be net of market revenues (A/S, energy profits which are defined as MCP – bid, and RUC Availability Payments). (This is consistent with the ISO's original proposal. The Commission rejected the netting proposal without prejudice when a resource adequacy program is implemented.)

7. Intrastate gas transportation and municipal use fees shall be included in minimum load energy costs. (These costs were not included under the ISO's original proposal or under the October 28 order.)

8. Use RMR Contract gas costs for RUC. This would involve using a two-day average of three daily indices (NGI So Cal Border, BTU So Cal Border and Gas Daily So Cal Gas large package) for SCE or SDG & E units, and a two-day average of two daily indices (NGI PG & E Citygate and Gas Daily PG & E citygate) for former PG & E units, plus any applicable intrastate transportation and municipal use fees. (This is a new provision.)

9. RUC capacity procured in the DA would be prevented from being used to serve export schedules in the HA. This is different from the ISO's previous proposal because DA RUC capacity would now be paid to serve ISO load (*i.e.*, there is no rescission of the Availability Payment). The ISO is considering two possible ways to implement this provision. Method 1 would involve enforcing a new constraint in the HA IFM: incremental exports are constrained to be less than or equal to incremental imports plus incremental generation from non-DA RUC capacity. Under this formula, DA RUC capacity would be available to be scheduled against control area load in the HA. Moreover, HA incremental exports could not cut into the DA RUC

capacity even if some of that capacity is not scheduled against control area load in HA. The ISO has not yet worked through the implementation details for this method and, at this time, is not certain how easy or difficult it may be to incorporate this constraint in the optimization. Method 2 is much simpler – the ISO would simply prohibit export purchases in the HA IFM. (This is a new provision.)

10. RMR dispatches that occur in RUC would not be eligible for setting or receiving the availability MCP. Similarly, any unit pre-designated as a capacity resource under a load serving entity's ("LSEs ") resource adequacy plan would not be eligible to receive or set the RUC availability MCP, provided both the resource owner and the LSE agree to this treatment.[1]

II. TREATMENT OF CONSTRAINED OUTPUT GENERATORS

1. COGs eligible to set prices, both in the integrated forward market ("IFM") and in Real-Time would be CTs that can only run at full output. This definition is consistent with the definition of Constrained Output Generators adopted by the Commission in its order on the ISO's Tariff Amendment No. 54.[2] *See California Independent System Operator Corporation*, 105 FERC ¶ 61,091 at P70 (2003).

2. The specification of the circumstances in which COG may set prices is as follows:

   a. Eligibility to set price in any settlement interval would depend on some portion of the unit's output being needed in merit order to serve load. In other words, if the unit is modeled as fully flexible to operate over its entire capacity range, it would receive a non-zero merit-order dispatch to clear the market.

   b. If the unit was needed in accordance with criterion 2.a in a previous settlement interval, and is still operating due to a minimum-run-time constraint, but none of its energy is needed in merit order in the current interval, the unit would not be eligible to set price in the current interval.

---

[1] One approach for implementing this may be through a RUC "self-provision" mechanism. The ISO has not yet developed a proposal for how such a mechanism would work.

[2] The Commission stated that COGs "are generating resources that cannot easily or economically change load levels and are typically restricted to generating at their full capacity for their unit-specific minimum run time. 105 FERC ¶ 61,091 at P 70.

3. The ISO is still evaluating some alternative ways to implement this proposal in the IFM design. One approach under consideration is the following:

   a. In the IFM dispatch run, all operating constraints of COG units would be observed. As a result of this run, a COG unit that it is needed per criterion 2.a would be dispatched at its P-max. At the same time, some cheaper energy may not be fully dispatched in this run due to the operating constraint on the COG unit.

   b. In the IFM pricing run following the dispatch run, all units would be set initially at their dispatch levels from the previous run. Those units that are eligible to set prices, including the COG units dispatched in the previous run, would be treated as flexible within a specified, constant-price operating interval of their dispatch levels. Thus, this run produces prices that are based only on the resources eligible to set prices.

III. ANCILLARY SERVICES PROCUREMENT

1. Under MD02, the ISO would not continue the currently approved practice of economic or price-based deferment of A/S procurement from DA to HA. The ISO has some concerns about this concession, however, due to the fact that its demand for A/S is determined by Western Electricity Coordinating Council ("WECC") reliability criteria and is therefore inelastic.

2. The ISO would set its DA procurement target at 100% of its estimated A/S requirements, based on its DA load forecast and allowing for A/S self provision. Because this approach is based on an estimation process, the ISO still may be required to procure some additional A/S in HA.

3. SCs who wish to defer some self-provision of A/S from DA to HA and avoid having the ISO procure A/S for their deferred quantities, would have to commit to a specific quantity of HA self provision in the DA scheduling time frame.[3] Such commitment would be

---

[3] Even with such commitments, the ISO would still face some risk of under-procurement of A/S. Therefore, it may be appropriate to set a limit on the amount of deferred self-provision a SC would be able to declare in DA. Moreover, ongoing discussions at NERC regarding A/S adequacy may lead to a new requirement to procure A/S fully in the DA time frame, which would make the issue of deferred self-provision moot.

binding, in the sense that failure to deliver the committed capacity would result in a penalty, such as a per-MW charge on the shortfall.

4. The ISO would procure additional A/S in the HA only when needed to supplement DA procurement due to unscheduled outages, changes in estimated A/S requirements (for example, due to revised load forecast or changes in the expected hydro-thermal supply mix), or possibly failure of the SCs to meet their DA commitments to self provide HA A/S capacity.

5. Sale of A/S in DA would be viewed as a binding commitment. HA buy-back by suppliers of DA A/S capacity would be allowed only in the event of unplanned outages that render the originally sold capacity unavailable. In this instance, the seller would buy back its DA A/S capacity at the higher of the DA or HA price.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in the above-captioned dockets.

Dated at Folsom, California, on this 24th day of February, 2004.

Anthony J. Ivancovich