Attachment A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**Docket Nos. EC96-19-___ and ER96-1663-___**

AMENDMENT NO. 6

SUBMITTED ON
March 23, 1998

ISO TARIFF AMENDMENT NO. 6

A. Temporary Changes to the Real-Time Market for Imbalance Energy

The ISO's recent coupled testing procedure included a test of the ISO's scheduling, Dispatch and Settlement systems. The testing required the PX, acting as Scheduling Coordinator for the Companies, and a limited number of other Scheduling Coordinators, to submit actual Schedules and bids to prove the ISO's ability to manage the various markets under its control efficiently and effectively. The results of coupled testing to date have revealed that the ISO may routinely receive an insufficient number of Supplemental Energy bids and Ancillary Service Energy bids, resulting in a "thin" market.

The implications of this, in relation to the ISO's responsibility as a Control Area operator beginning on the ISO Operations Date, are significant. If, upon start-up, there continues to be a "thin" market for Supplemental Energy and Ancillary Services, the ISO's ability to balance Generation and Demand on a real time basis, in compliance with NERC and WSCC minimum operating criteria, could be threatened. In fact, the ISO's difficulty in following ramps during the coupled test was, in large part, attributable to not having adequate Regulation.

During the coupled test, the ISO determined that some of the causes of "thin" markets were associated with pricing arrangements and, specifically, the way in which the ISO's software – for balancing Energy and *ex post* pricing ("BEEP") – operated. Moreover, the Companies informed the ISO that reliability could deteriorate further in the real markets when strategies would focus, even more, on prices – and not operations – for most Scheduling Coordinators.

Accordingly, the ISO quickly modified the BEEP software, and its later success in the coupled test demonstrated the efficacy of the modifications. Further software changes will be installed prior to start-up. This amendment will make the ISO Tariff consistent with the modified software.

A brief description of BEEP is useful to introduce the issues.

The ISO is responsible for the real-time Dispatch of (1) Generating Units, (2) Curtailable Demands and (3) interchange schedules to meet real time imbalances. The ISO determines the merit order stack for real time sources of balancing Energy by utilizing its BEEP software.

In the original ISO system design, BEEP would determine the Dispatch instructions required for each five minute interval, Dispatch instructions would be given, and parties would be billed based on actual *vs.* Final Schedules for the same five minutes -- the Settlement Period. When the ISO decided to stage implementation of the five minute Settlement Period, it adopted an Hourly Ex Post Price, based on the average of the Five Minute Ex Post Prices. BEEP, however, was not modified. Instead, BEEP was designed and installed pursuant to the original assumptions -- to operate on a five minute interval.

In addition, during the coupled test, the ISO -- for the first time **--** identified irregularities in the effects of BEEP software on economic Dispatch. Coupled testing also identified, and proved the existence of, a number of other problems, both operational and commercial, as follows.

- BEEP, as designed and installed, assumed that all of its previous Dispatch instructions were, in fact, communicated by the ISO operators to, and implemented accordingly by, Scheduling Coordinators. BEEP calculated the Five Minute Ex Post Price on this basis. However, the ISO's dispatchers cannot precisely respond to BEEP's recommended Dispatch instructions on a five minute interval basis; in fact, even with an additional operator on shift, not every call can be made.

- Partly because of the requirement to route Dispatch instructions *via* Scheduling Coordinators, BEEP's recommendations cannot be followed on a five minute interval basis, even when instructions are given in a timely fashion by the ISO.

- The five minute Dispatch interval is inconsistent with actual unit operating capabilities in many cases (*e.g.*, the out-of-state coal units, which are essential to the Ancillary Services and Supplemental Energy market, generally cannot be moved more than once per hour, and some pumped-storage hydro units must pump for at least an hour before being reversed).

- Dispatch based upon the marginal unit in each five minute interval, with payment based upon the hourly average of the five minute prices, leads to inequities. The actual payment to Scheduling Coordinators for incremental Energy requested by the ISO can be less than the price bid by the marginal unit dispatched in the five minute interval; conversely, the payment by Scheduling Coordinators for decremental Energy (*e.g.* Generation reductions) requested by the ISO could be greater than the price bid by the marginal unit chosen in the five minute interval. The owners of these units informed the ISO that they would withhold the units from the Supplemental Energy and Ancillary Services market after start-up, rather than risk economic losses.

- The ISO requirement for Supplemental Energy bids to be received no later than 30 minutes prior to the operating hour, and the five minute scheduling intervals of BEEP, are inconsistent with the scheduling requirements of adjacent Control Areas, thereby discouraging Supplemental Energy bids from outside the ISO Control Area.

- A number of highly-desirable units were being withheld from the Supplemental Energy and Ancillary Services markets because the requirement for unit-specific Dispatch makes operation problematic for physically interdependent units, (*e.g.*, those in a sequential hydro system).

These problems are, if unsolved, sufficient to keep the ISO from commencing operations. In order to address these difficulties, the ISO made adjustments to its BEEP software and various operating procedures. Many of the adjustments have been tested and the results demonstrate their efficacy in addressing the reliability concerns.

A number of these adjustments may be eliminated once the Dispatch period and the Settlement Period are parallel (when the sub-hour Settlement Period is adopted pursuant to the ISO staging plan). Until then, and until the ISO and its stakeholders have revisited these issues in a comprehensive fashion, the adjustments are those which are set out in new ***interim*** Section 23 of the ISO Tariff that will:

- allow the ISO to adjust the BEEP interval, subsequent to issuing a notice to Scheduling Coordinators, to a value ranging from five minutes to thirty minutes;[1]

- allow Scheduling Coordinators, when responding to a Dispatch instruction, to advise the ISO operators of a minimum run time, up to one hour, between Dispatch instructions;[2]

- change the deadline for Scheduling Coordinators' submittals of Supplemental Energy bids, from thirty minutes prior to the Settlement Period, to forty-five minutes prior to the Settlement Period, to accommodate offers of Supplemental Energy imported from sources

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[1] This interval was set at 10 minutes during the last days of the coupled test. The ISO expects the 10 minute interval to be used initially, but needs the flexibility to lengthen it if operational constraints suggest that 10 minutes is not an adequate period.

[2] Initially, this notice cannot be submitted with a bid, but rather may only be given orally when the Scheduling Coordinator is called by the ISO operator.

located in other Control Areas without violating WSCC interchange scheduling practices;

- clarify that physically interlinked resources (*i.e.* those associated with river or aqueduct systems) can be bid as a Physical Scheduling Plant, rather than on a resource-specific basis;

- clarify that actual Dispatch will be based on the ISO operator's prudent response to BEEP instructions, rather than a strict adherence to BEEP instructions, with the requirement that ISO dispatchers log the variations from BEEP instructions; and

- provide that, upon securing permission from a Scheduling Coordinator, the ISO may contact operators of Generators and Loads directly, for purposes of instructing incremental or decremental changes resulting from bids submitted by the Scheduling Coordinator, without having to communicate with them through their appointed Scheduling Coordinator.[3]

In addition, and most importantly, the ISO is changing the basis on which Scheduling Coordinators are compensated for accepted Supplemental Energy and Ancillary Service bids. This change will be effective for as long as the Settlement Period (currently an hour) and the Dispatch interval (currently less than an hour) are not the same. Until then, the ISO will settle with Scheduling Coordinators, for ***instructed deviations*** from their Schedules, as follows:

- for incremental Energy, the ISO will pay the Scheduling Coordinator, for each interval (i.e. 10 minutes, initially), at the higher of the bid price or the marginal incremental price for each interval, for the duration of the instructed deviation; and

- for decremental Energy, the Scheduling Coordinator will pay the ISO for each interval (i.e. 10 minutes, initially), at the lower of the bid price or the marginal price for each interval, for the duration of the instructed deviation.

The ISO will continue to settle with Scheduling Coordinators for ***uninstructed deviations*** in accordance with Section 11.2.4.1 of the ISO Tariff ("Net

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[3] Some Scheduling Coordinators expressed concern that direct communications would leave them without adequate information for their own settlement systems. The ISO assumes that a Scheduling Coordinator would not give its consent without having adopted internal procedures to capture necessary information directly from any Generator or Load called directly by the ISO.

Settlements for Imbalance Energy"). Section 2.5.23 is, however, being amended to reflect the different interval periods (*i.e.*, 10 minutes, initially) used to calculate the Hourly Ex Post Price.

In addition, the amendment reflects the fact that BEEP calculates the price based on BEEP's instructions, whether or not the operator is able to communicate with the Scheduling Coordinator and whether or not the unit in fact responds. Eventually, the ISO intends to modify BEEP to calculate prices based on ***actual*** performance. This is not, however, possible in the short-run. The difference between BEEP's calculation and actual marginal prices is not expected to be significant, but there is the potential for a variance. The ISO has made software changes since the commencement of the coupled test and the ISO plans to modify its software further to continue to narrow the potential for variance until the more comprehensive software redesign can be implemented.

Any special adjustments, required to maintain revenue neutrality under this temporary regime, will be accounted for in accordance with section 3.1.1(c) of the ISO Settlement and Billing Protocol. This is discussed below under section.J, Changes Regarding Neutrality Adjustments.

As noted above, because many of the problems with Supplemental Energy and Ancillary Services Energy relate to the duration of the BEEP Dispatch interval and the hourly Settlement Period not being the same, Section 23 is an interim provision. A number of comments from Scheduling Coordinators reflected a willingness to abide by the above-described changes as an interim measure, but expressed their discomfort with the short period in which they had to review the changes and consider their implications. The ISO agrees.

A comprehensive stakeholder process will be undertaken after start-up to determine how best to implement a sub-hour Settlement Period, pursuant to the ISO staging plan. The process will also look at how BEEP should be further redesigned and the other interim measures. At the conclusion of that process, the ISO will seek termination of this interim Section, identify which measures should be made permanent, and make other changes, all in a comprehensive ISO Tariff amendment.

23 Temporary Changes to the Real-Time Market for Imbalance Energy

23.1 Application

Notwithstanding any other provision of the ISO Tariff, the amendments to the ISO Tariff set forth in Sections 23.2 through 23.5 shall continue in effect until such time as:

(a) the ISO has applied to the FERC for new, long-term, changes to

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the ISO Tariff in regard to the Real-Time Market for Imbalance Energy, in connection with implementing a sub-hour Settlement Period; and

(b) the FERC has approved new, long-term, changes to the ISO Tariff in regard to the Real Time Market for Imbalance Energy.

23.2 ISO Tariff Amendments

23.2.1 Amendments to the Body of the ISO Tariff

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2.5.22.4.1 Timing of Supplemental Energy Bids.

Supplemental Energy bids must be submitted to the ISO no later than forty-five (45) ~~30~~ minutes prior to the operating hour. Bids may ~~also~~ be submitted at any time after the Day-Ahead Market closes. These Supplemental Energy bids cannot be withdrawn after forty-five (45) ~~thirty (30)~~ minutes prior to the Settlement Period. The ISO may dispatch the associated resource at any time during the Settlement Period.

2.5.22.10 Dispatch instructions. Dispatch instructions shall include the following information:

(a) name of the Generating Unit, Load or System Resource being dispatched;

(b) specific MW value to which the Generating Unit, Load or System Resource is being dispatched;

(c) operating level and price point to which the Generating Unit, Load or System Resource is being dispatched;

(d) time the Generating Unit, Load or System Resource is required to achieve the dispatch instruction;

(e) time of the dispatch instruction; and

(f) any other information which the ISO considers relevant.

All Dispatch instructions except those for the Dispatch of Regulation (which will be communicated by direct digital control signals) will be communicated by telephone. Except in the case of deteriorating system conditions or emergency, and except for instructions for the Dispatch of Regulation, the ISO will send all Dispatch instructions to the Scheduling Coordinator for the Generating Unit, Load or System Resource which it wishes to Dispatch. The recipient Scheduling Coordinator shall ensure that the Dispatch instruction is communicated immediately to the operator of the Generating Unit or Load concerned. The ISO may, with the prior permission of the

Scheduling Coordinator concerned, communicate with and give Dispatch instructions to the operators of Generating Units and Loads directly without having to communicate through their appointed Scheduling Coordinator. The recipient ~~Scheduling Coordinator~~ of a Dispatch instruction shall confirm the Dispatch instruction by repeating the Dispatch instruction to the ISO. The ISO shall record on tape all voice conversations which occur on the dispatch instruction communication equipment. These recordings may be used to audit the dispatch instructions, and to verify the response of Generating Units, Loads and System Resources to dispatch instructions.

The ~~dispatch~~ Dispatch instruction and all information associated with it shall be logged and recorded by the ISO as soon as practical after issuing each instruction. The ISO will develop detailed operational protocols governing the content, issue, receipt, confirmation and recording of ~~dispatch~~ Dispatch instructions.

2.5.23.1 **General Principles.** Imbalance Energy shall be priced ~~in two time intervals~~ using the BEEP Interval ~~Five Minute~~ Ex Post Prices for Instructed Imbalance Energy per resource and the Hourly Ex Post Price for Uninstructed Imbalance Energy. The ~~Five Minute~~ Ex Post Prices shall be based on the bid of the marginal Generating Units, Loads and System Resources dispatched by the ISO to reduce Demand or to increase or decrease Energy output in each BEEP Interval ~~five minute period~~ (including resources that provide Imbalance Energy and Ancillary Services resources that increase or decrease Energy output or reduce Demand).

The marginal Generating Unit, Load or System Resource dispatched in each BEEP Interval ~~the five minute period~~ is

(a) if ~~generation~~ Generation output is increased, or Demand reduced, the Generating Unit, Load or System Resource with the highest bid that is accepted by the ISO's BEEP Software for incremental Generation, or Demand reduction; or

(b) if ~~generation~~ Generation output is decreased, the Generating Unit or System Resource with the lowest bid that is accepted by the ISO's BEEP Software for decremental Generation.

~~Where a Scheduling Coordinator has identified specific Generating Units, Loads or System Resources as the providers of the additional Operating Reserve required to cover any Interruptible Imports and on-demand obligations which it has scheduled, the Proxy Energy Bid prices of those resources for the incremental Energy, or decremental~~

~~Demand, dispatched by the ISO from the Operating Reserve provided by those resources, shall not be taken into account in the determination of the Hourly Ex Post Price.~~

When an Inter-Zonal Interface is operated at the capacity of the interface (whether due to scheduled uses of the interface, or decreases in the capacity of the interface), the marginal incremental or decremental bid prices in some Zones may differ from one another. In such cases, the ISO will determine separate ~~Hourly~~ Ex Post Prices for the Zones.

The ISO will respond to the Dispatch instructions issued by the BEEP Software to the extent practical in the time available and acting in accordance with Good Utility Practice. The ISO will record the reasons for any variation from the Dispatch instructions issued by the BEEP Software.

2.5.23.2 Determining ~~Five Minute Ex Post Price and Hourly~~ Ex Post Prices

2.5.23.2.1 BEEP Interval Ex Post Prices. For each ~~five minute period~~BEEP Interval, the ISO will compute an updated dispatch price curve, using the Generating Units, Loads and System Resources dispatched according to the ISO's BEEP Software during that time period to meet Imbalance Energy requirements. For each BEEP Interval of the Settlement Period, BEEP will compute an incremental Ex Post Price and a decremental Ex Post Price. The incremental Ex Post Price will equal the highest price bid selected in the BEEP Interval. The decremental Ex Post Price will equal the lowest price bid selected in the BEEP Interval. The ~~Five Minute~~ Ex Post Prices for each ~~five minute period~~BEEP Interval will equal the marginal bid of the marginal Generating Unit, Load, or System Resource as described in Section 2.5.23.1.

~~If the net quantity of Imbalance Energy in the five minute period t is positive then~~The BEEP Interval incremental Ex Post Price will be computed for each BEEP Interval i as

~~$P5Min_t = Max(EnBid_t)_t$~~

$PI_i = Max(EnBid_r)_i$

The BEEP Interval decremental Ex Post Price will be computed for each BEEP Interval i as

$PD_i = Min(EnBid_r)_i$

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~~Where~~where

$EnBid_{r\,\cancel{i}}$ = Energy bid price~~s~~ of the ~~Generating Units, Loads and System~~ ~~Resources~~ resources providing Ancillary ~~Services~~Service Energy~~, and the~~ or Supplemental Energy. ~~bids of other Generating Units, Loads and System Resources dispatched by the ISO during the five minute period.~~

~~If the net quantity of Imbalance Energy in the five minute period t is negative then~~

~~$P5Min_t = Min(EnBid_t)_t$~~

In the event of Inter-Zonal Congestion, the ISO will develop a dispatch price curve, and BEEP Interval Ex Post Prices ~~an Ex Post Five Minute Price $P5Min_{xt}$,~~ for each Zone where congestion exists.

2.5.23.2.2 Hourly Ex Post Price Applicable to Uninstructed Deviations. The Hourly Ex Post Price applicable to uninstructed deviations in Settlement Period t in each zone will equal the Energy weighted average of the BEEP Interval ~~12 Five Minute Ex Post Prices~~Charges in each Zone, calculated as follows:

$$\cancel{PHourExPost_x = \frac{\sum_{t=1}^{12}(P5Min_{xt} * SysDev)_t}{\sum_{t=1}^{12} SysDev_t}}$$

$$PHourExPost_x = \frac{\sum_{ji}\left|IIEC_{jix}\right|}{\sum_{ji}\left|IMWH_{jix}\right|}$$

where:

$PHourExPost_x$ = Hourly Ex Post Price in Zone x

HBI = the number of BEEP intervals in the Settlement Period

j = the number of Scheduling Coordinators with instructed deviations

$IIEC_{jix}$ = the Instructed Imbalance Energy Charges for Scheduling Coordinator j for the BEEP interval i in Zone x.

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$IMWH_{jix}$ = the Instructed Imbalance Energy for Scheduling Coordinator j for the BEEP interval i in Zone x

~~$P5Min_{xt}$ = Five minute Ex Post Price in Zone x in period t~~

~~$SysDev_t$ = the absolute difference (whether positive or negative) between (the deviation between scheduled and metered Demand) and (the deviation between scheduled and metered Generation) in five minute period t in Zone x.~~

If the ISO declares a System Emergency, e.g. during times of supply scarcity, and involuntary load shedding occurs during the real time ~~dispatch~~Dispatch, the ISO shall set the Hourly Ex Post Price at the Administrative Price.

11.2.4.1 Net Settlements for Uninstructed Imbalance Energy.

Uninstructed Imbalance Energy attributable to each Scheduling Coordinator in each Settlement Period in the relevant Zone shall be deemed to be sold or purchased, as the case may be, by the ISO and payments for Uninstructed Imbalance Energy shall be settled by debiting or crediting, as the case may be, the Scheduling Coordinator with an amount for each Settlement Period equal to:

$IE\ Charge =$

$$\left(\sum_i GenDev_i - \sum_i LoadDev_i\right) * P + \left(\sum_q ImpDev_q\right) * P - \left(\sum_q ExpDev_q\right) * P\ +\ UFEC$$

where:

The deviation between scheduled and actual Energy Generation for Generator i represented by the Scheduling Coordinator for the Settlement Period is calculated as follows:

$$GenDev_i = G_s * GMM_f - \left[\left(G_a - G_{adj}\right) * GMM_{ah} - G_{a/s}\right]$$

The deviation between scheduled and actual Load consumption for Load i represented by the Scheduling Coordinator for the Settlement Period is calculated as follows:

$$LoadDev_i = L_s - \left[\left(L_a - L_{adj}\right) + L_{a/s}\right]$$

The deviation between forward, scheduled and Real Time adjustments to Energy imports, adjusted for losses, for Scheduling Point q represented by the Scheduling Coordinator for the Settlement Period is calculated as follows:

$$ImpDev_q = I_s * GMM_{fq} - \left[\left(I_a - I_{adj}\right) * GMM_{ahq}\right] + I_{a/s}$$

The deviation between forward, scheduled and Real Time adjustments to Energy exports for Scheduling Point q represented by the Scheduling Coordinator for the Settlement Period is calculated as follows:

$$ExpDev_q = E_s - E_a - E_{adj}$$

and where:

$\boldsymbol{G_s}$ = sum of effective schedules for Day-Ahead and Hour-Ahead

$\boldsymbol{GMM_f}$= estimated GMM for Day-Ahead

$\boldsymbol{G_a}$ = actual metered Generation

$\boldsymbol{G_{adj}}$ = deviations in real time ordered by the ISO for purposes such as Congestion Management

$\boldsymbol{GMM_{ah}}$= hour-ahead GMM (proxy for ex-post GMM)

$\boldsymbol{G_{a/s}}$ = Energy generated from Ancillary Service resource or Supplemental Energy resource due to ISO dispatch instruction

$\boldsymbol{L_s}$ = sum of Demand scheduled for Day-Ahead and Hour-Ahead

$\boldsymbol{L_a}$ = actual metered Demand

$\boldsymbol{L_{adj}}$ = Demand deviation in real time ordered by ISO for purposes such as Congestion Management

$\boldsymbol{L_{a/s}}$ = Demand reduction from Ancillary Service resource due to ISO dispatch instruction

$\boldsymbol{GMM_{fq}}$= estimated GMM for an Energy import at Scheduling Point q for Day-Ahead

GMM_{ahq} = estimated GMM for an Energy import at Scheduling Point q for Hour-Ahead (proxy for ex-post GMM)

I_s = sum of Scheduled Energy import scheduled through Scheduling Point q for Day-Ahead and Hour-Ahead

I_a = sum of actual Energy import scheduled through Scheduling Point q.

I_{adj} = deviation in real time import ordered by ISO for purposes such as Congestion Management, and import curtailment.

$I_{a/s}$ = Energy generated from Ancillary Service System Resources pursuant to Existing Contracts or Supplemental Energy from interties due to dispatch instruction

E_s = sum of scheduled Energy export scheduled through Scheduled Point q for Day-Ahead and Hour-Ahead

E_a = sum of actual Energy export scheduled through Scheduling Point q for Day-Ahead and Hour-Ahead

E_{adj} = deviation in real time export ordered by ISO for purposes such as Congestion Management, and export curtailment

P = Hourly Ex Post Price for Uninstructed Imbalance Energy for the relevant hour, as defined in Section 2.5.23.2.2

UFEC = the Unaccounted for Energy Charge for the Scheduling Coordinator calculated as follows:

Unaccounted for Energy Charge

The hourly Unaccounted for Energy Charge on Scheduling Coordinator j for Settlement Period t for each relevant Zone is calculated in the following manner:

The UFE for each utility service territory *k* is calculated as follows,

$$E_{UFE\_UDC\_k} = \left(I_k - E_k + G_k - \left(RTM_k + LPM_k\right) - TL_k\right)$$

The Transmission Loss calculation per Settlement Period t per relevant Zone for each utility service territory k is calculated as follows,

$$TL_k = \sum [G_a * (1 - GMM_{ah})] + \sum [I_a (1 - GMM_{ahq})]$$

Each metered demand point, either ISO grid connected or connected through a UDC, is allocated a portion of the UFE as follows:

$$E_{UFE\_z} = \frac{D_z}{\sum_Z D_z} E_{UFE\_UDC\_k}$$

The UFE charge for Scheduling Coordinator j per Settlement Period per relevant Zone is then,

$$UFEC_j = \left(\sum_z E_{UFE\_z} \right) * P_{xt}$$

Where the terms used in the equations have the following meaning:

$E_{UFE\_UDC\_k}$ -- MWh

The Unaccounted for Energy (UFE) for utility service territory k.

E_{UFE_z} -- MWh

The portion of Unaccounted for Energy (UFE) allocated to metering point z.

I_k -- MWh

The total metered imports into utility service territory k in Settlement Period t.

E_k -- MWh

The total metered exports from utility service territory k in Settlement Period t.

G_k -- MWh

The total metered Generation in Settlement Period t in utility service territory k.

RTM_k -- MWh

The Settlement Period t total of the real-time metering in utility service territory k in Settlement Period t.

LPM_k -- MWh

The calculated total of the Load Profile metering in utility service territory k per Settlement Period t.

TL_k -- MWh

The Transmission Losses per Settlement Period t in utility service territory k.

D_z -- MWh

The Demand including Exports in Settlement Period t at metered point z.

Replacement Reserve Dispatch Charge

For each Scheduling Coordinator whose Generators falls below its Schedule, or whose Demand exceeds its Schedule, such that the net Schedule is unbalanced, the following additional charge will apply:

$$RepResDispChrg_{jt} = D_{jt} * RRDispCost_i$$

where:

$$\cancel{D_{jt} =} \frac{Max\left(0,\left\{\sum_i GenDev_i - \sum_i LoadDev_i + \sum_q ImpDev_q + \sum_q ExpDev_q + E_{UFE\_jk}\right\}\right)}{\sum Max\left(0,\left\{\sum_i GenDev_i - \sum_i LoadDev_i + \sum_q ImpDev_q + \sum_q ExpDev_q + E_{UFE\_jk}\right\}\right)}$$

$$D_{jt} = \frac{Max\left(0,\left\{\sum_i GenDev_i - \sum_i LoadDev_i + \sum_q ImpDev_q + \sum_q ExpDev_q + E_{UFE\_jk}\right\}\right) * ReplObligRatio_{jxt}}{\sum\left(Max\left(0,\left\{\sum_i GenDev_i - \sum_i LoadDev_i + \sum_q ImpDev_q + \sum_q ExpDev_q + E_{UFE\_jk}\right\}\right) * ReplObligRatio_{jxt}\right)}$$

where:

$$ReplObligRatio_{jxt} = \frac{ReplOblig_{jxt}}{\sum_j ReplOblig_{jxt}}$$

$ReplOblig_{jxt}$ is the replacement reserve capacity obligation as defined in Section 2.5.28.4; and

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~~where:~~

RRDispCost is defined in Section 2.5.28.4 of this ISO Tariff.

If there is Congestion in the Day-Ahead Market the ISO will allocate the Replacement Reserve Dispatch Charges on a Zonal basis. If there is no Congestion in the Day-Ahead Market the ISO will allocate the Replacement Reserve Dispatch Charges on a ISO Control Area-wide basis (irrespective of whether there is Congestion in the Hour-Ahead Markets or not).

This additional charge *(RepResDispChrg)* allocates the cost of dispatched Replacement Reserve to Scheduling Coordinators in proportion to their contribution to the need for the dispatch of that Replacement Reserve, as measured by the magnitude of the Energy insufficiency served through the Imbalance Energy market. The ISO shall develop protocols and procedures for the monitoring of persistent intentional excessive imbalances by Scheduling Coordinators and for the imposition of appropriate sanctions and/or penalties to deter such behavior. The net balance of the charges attributable to all Scheduling Coordinators represents the Transmission Losses imbalance total for each hourly Settlement Period.

11.2.4.1.1 Settlement for Instructed Imbalance Energy

Instructed Imbalance Energy attributable to each Scheduling Coordinator J in each Settlement Period t in the relevant Zone shall be deemed to be sold or purchased, as the case may be, by the ISO and payments for Instructed Imbalance Energy shall be settled by debiting or crediting, as the case may be, the Scheduling Coordinator with an amount for each Settlement Period t equal to:

$IIEC_j = IGDC_j + ILDC_j + IIDC_j$

where:

Instructed Generation Deviation Payment/Charge is calculated as follows:

$$IGDC = \sum_{gi} \frac{G_{gi} * P_i}{HBI}$$

Instructed Load Deviation Payment/Charge is calculated as follows:

$$ILDC = \sum_{Li} \frac{L_{Li} * P_i}{HBI}$$

Instructed Import Deviation Payment/Charge is calculated as follows:

$$IIDC = \sum_{Ii} \frac{I_{Ii} * P_i}{HBI}$$

and where:

$IGDC_j$ =total of instructed Generation deviation payments/charges for the Settlement Period t

$ILDC_j$ =total of instructed Demand deviation payments/charges for the Settlement Period t

$IIDC_j$ =total of instructed import deviation payments/charges for the Settlement Period t

G_{gi} ~~g-i~~ =instructed Energy (in MW) for Generating Unit g during BEEP Interval i

L_{Li} ~~L-i~~ =instructed Energy (in MW) for Load L during BEEP Interval i

I_{Ii} ~~I-i~~ =instructed Energy (in MW) for import I during BEEP Interval i

P_i ~~ti~~ = the BEEP incremental Ex Post Price for BEEP Interval i if the net instructed Energy for resources is positive. Or,or the BEEP decremental Ex Post Price for BEEP Interval i if the net instructed Energy for resources is negative

HBI=the Number (2-12) of BEEP Intervals in the Settlement Period: the maximum number of intervals in the Settlement Period that BEEP can instruct a resource for incremental/decremental Energy.

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23.2.2 Amendments to the Master Definitions in the ISO Tariff

BEEP Interval	The time period, which may range between five (5) and thirty (30) minutes, over which the ISO's BEEP Software measures deviations in Generation and Demand, and selects Ancillary Service and Supplemental Energy resources to provide balancing Energy in response to such deviations. As of the ISO Operations Date, the BEEP Interval shall be ten (10) minutes. The ISO may, by seven (7) days' notice published on the ISO's Home Page, at http://www.caiso.com (or such other internet address as the ISO may publish from time to time), increase or decrease the BEEP Interval within the range of five (5) to thirty (30) minutes.
BEEP Interval Ex Post Prices	The prices charged to or paid by Scheduling Coordinators for Instructed Imbalance Energy in each Zone in each BEEP Interval. The prices will vary between Zones if Congestion is present. The BEEP Interval Ex Post Price is equal to the bid price of the marginal resource accepted by the ISO for Dispatch and deemed eligible by the ISO to set the price during the BEEP Interval. for each BEEP

	Interval: the BEEP Interval Ex Post Price for incremental Energy will equal the highest price bid selected by the BEEP software; and the BEEP Interval Ex Post Price for decremental Energy will equal the lowest price bid selected by the BEEP software.
BEEP Software	The balancing energy and ex post pricing software which is used by the ISO to determine which Ancillary Service and Supplemental Energy resources to Dispatch and to calculate the Ex Post Prices.
Ex Post Price	The Hourly Ex Post Price or the BEEP Interval Ex Post Prices.
Uninstructed Imbalance Energy	The real time change in Generation or Demand other than that instructed by the ISO or which the ISO Tariff provides will be paid at such price.
~~**Five Minute Ex Post Price**~~	~~The price charged or paid to Scheduling Coordinators responsible for Participating Generators, System Resources or Participating Buyers for Imbalance Energy in each Zone. The price will vary between Zones if Congestion is present. This five minute price is equal to the bid price of the~~

~~marginal resource accepted by the ISO for dispatch and deemed eligible under the ISO Tariff to set the price during a five minute period.~~

Hourly Ex Post Price	The price charged or paid to Scheduling Coordinators responsible for Participating Generators and Participating Buyers for Imbalance Energy in each Zone. The price will vary between Zones if Congestion is present. The Hourly Ex Post Price is the Energy weighted average of the BEEP Interval ~~12 Five Minute~~ Ex Post Prices in each Zone during each Settlement Period.
Instructed Imbalance Energy	The real time change in Generation output or Demand (from dispatchable Generating Units or Loads) which is instructed by the ISO to ensure that reliability of the ISO Control Area is maintained in accordance with Applicable Reliability Criteria. Sources of Imbalance Energy include Regulation, Spinning and Non-spinning Reserves, Replacement Reserve, and Energy from other Generating Units that are able to respond to the ISO's request for more or less Energy.

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23.3 Amendments to the Dispatch Protocol

DP 3.2 Supplemental Energy

In addition to the Final Schedules, Supplemental Energy bids will be available to the ISO real time dispatchers, as described in the SBP, by forty-five (45) ~~30~~ minutes prior to the start of the Settlement Period to which such Supplemental Energy bids apply.

DP 3.4.3 Verbal Communication with Generators

Normal verbal communication of Dispatch Instructions between the ISO and Generators will be via the relevant SC. Each SC must immediately pass on to the Generator concerned any verbal communication for the Generator which it receives from the ISO. If the ISO considers that there has been a failure at a particular point in time or inadequate response over a particular period of time by the Generating Units to the Dispatch Instruction, the ISO will notify the relevant SC. The ISO may, with the prior permission of the Scheduling Coordinator concerned, communicate with and give Dispatch instructions to the operators of Generating Units and Loads directly without having to communicate through their appointed Scheduling Coordinator. In situations of deteriorating system conditions or emergency, the ISO reserves the right to communicate directly with the Generator(s) as required to ensure System Reliability.

23.4 Amendments to the Schedules and Bids Protocol

SBP 4.1 Content of Adjustment Bids

Adjustment Bids are contained in Preferred Schedules and Revised Schedules submitted by SCs for particular Generating Units (including Physical Scheduling Plants), Dispatchable Loads and external imports/exports. Adjustment Bids cannot be submitted with respect to Inter-Scheduling Coordinator Trades.

Each SC is required to submit a preferred operating point for each Generating Unit, Dispatchable Load and external import/export (these quantities are presented in the SC’s submitted Schedule as “Hourly MWh”). The SC's preferred operating point for each Generating Unit, Dispatchable Load and external import/export must be within the range of any

Adjustment Bids to be used by the ISO. The minimum MW output level, which may be zero MW (or negative for pumped storage resources), and the maximum MW output level must be physically achievable.

SBP 5.1 Content of Ancillary Services Schedules and Bids

Ancillary Services in the Day-Ahead Market and the Hour-Ahead Market are comprised of the following: Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve. Each Generating Unit (including Physical Scheduling Plants), System Unit, Curtailable Demand or external import/export for which a SC wishes to submit Ancillary Services schedules and bids must meet the requirements set forth in the Ancillary Services Requirements Protocol (ASRP). For each Ancillary Service offered to the ISO auction or self-provided, SCs must include a bid price for Energy in the form of a staircase function composed of up to eleven (11) ordered pairs (i.e., ten (10) steps or price bands) of quantity/price information. These staircase functions must be either monotonically non-decreasing (Generating Units, System Units, and external imports) or monotonically non-increasing (Curtailable Demands and external exports). The same resource capacity may be offered into more than one ISO Ancillary Service auction at the same time (the sequential evaluation of such multiple offers between Ancillary Services markets to eliminate double counting of capacity is described in the SP). In each category of Ancillary Service, the reference to "Revised" types of Schedules indicates a submittal which is part of a Revised Day-Ahead Schedule as described in the SP. Each of the following data sections can be submitted up to seven (7) days in advance. There is no provision for external imports/exports with regard to Ancillary Services bids, only self-provided Ancillary Service schedules under Existing Contracts. The functionality necessary to accept such bids does not exist in the ISO scheduling software.

SBP 6.1.1 Generation Section of Supplemental Energy Bid Data

Each SC offering Supplemental Energy to the ISO will submit the following information for each Generating Unit for each Settlement Period:

(a) SC's ID code;

(b) name of Generating Unit;

(c) Generating Unit operating limits (high and low MW);

(d) Generating Unit ramp rate in MW/minute; and

(e) the MW and $/MWh values for each Generating Unit for which a Supplemental Energy bid is being submitted consistent with this SBP 6.

A Physical Scheduling Plant shall be treated as a single Generating Unit for Supplemental Energy bid purposes.

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23.5 Amendments to the Settlement and Billing Protocol

~~C 2.1.3 Real-Time Market~~

~~Each Scheduling Coordinator will be paid for the real time instructed Energy output from Dispatched Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve[1] resources which it represents at the real time Hourly Ex Post Price, in accordance Appendix D, section D 2.1.2. Each Scheduling Coordinator will also be paid for Supplemental Energy Dispatched from resources which it represents at the same Hourly Ex Post Price. This payment for Scheduling Coordinator j for providing Energy output from a resource i in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{EnQPay_{ijxt} = EnQ_{ijxt} * P_{xt}}$$

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~~The total payment to each Scheduling Coordinator for real time Energy output from all resources which it represents for a given Trading Interval in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{EnQPayTotal_{ijxt} = \sum_i EnQPay_{ijxt}}$$

[1] For Regulation, differences between instructed and metered Energy shall be settled as Uninstructed Imbalance Energy in accordance with Appendix G2.1.

C 3.18 EnQ_{ijx} – MWh
The Dispatched and supplemental Energy output in the Real Time Market from resource i by Scheduling Coordinator j in Zone x for.

C 3.20 P_{xt} - $/MWh
The Hourly Ex Post Price of Imbalance Energy in the Real Time Market in Zone x for Trading Interval t.

~~D 2.1~~D 2.1.1 Uninstructed Imbalance Energy Charges on Scheduling Coordinators

The Imbalance Energy charge for ~~Trading Interval t~~ Settlement Period t for Scheduling Coordinator j for Zone x is calculated using the following formula:

$$IEC_j = \left(\sum_i GenDev_i - \sum_i LoadDev_i\right) * P_{xt} + \left(\sum_q ImpDev_q\right) * P_{xt} - \left(\sum_q ExpDev_q\right) * P_{xt} + UFEC_j$$

The deviation between scheduled and actual Energy Generation for Generator i represented by Scheduling Coordinator j in Zone x during ~~Trading Interval t~~ Settlement Period t is calculated as follows:

$$GenDev_i = G_s * GMM_f - [(G_a - G_{adj}) * GMM_{ah} - G_{a/s}]$$

The deviation between scheduled and actual Load consumption for Load i represented by Scheduling Coordinator j in Zone x during Trading Interval t is calculated as follows:

$$LoadDev_i = L_s - \left[\left(L_a - L_{adj}\right) + L_{a/s}\right]$$

The deviation between forward scheduled and Real Time adjustments to Energy imports[1], adjusted for losses, for Scheduling Point q represented by Scheduling Coordinator j into zone x during ~~Trading Interval t~~ Settlement Period t is calculated as follows:

[1] Note that this deviation is a difference between a forward Market value and a Real Time value. It is not inadvertent energy.

[2] Note that this deviation is a difference between a forward Market value and a Real Time value. It is not inadvertent energy.

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$ImpDev_q = I_s * GMM_{fq} - [(I_a - I_{adj}) * GMM_{ahq}] + I_{a/s}$

The deviation between forward scheduled and Real Time adjustments to Energy exports[2] for Scheduling Point q represented by Scheduling Coordinator j from Zone x during ~~Trading Interval t~~ Settlement Period t is calculated as follows:

$ExpDev_q = E_s - Ea - E_{adj}$

The Hourly Ex Post Price applicable to uninstructed deviations in Settlement Period t in each zone will equal the Energy weighted average of the BEEP Interval charges in each zone, calculated as follows:

$$P_{xt} = \frac{\sum_{ji} \left| IIEC_{jix} \right|}{\sum_{ji} \left| IMWH_{jix} \right|}$$

Where:

P_{xt} = the Hourly Ex Post Price in Zone x

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$IIEC_{jix}$ = the Instructed Imbalance Energy Charges for Scheduling Coordinator j for BEEP Interval i in Zone x

$IMWH_{jix}$ = the Instructed Imbalance Energy for Scheduling Coordinator j for the BEEP Interval i in Zone x

D 2.1.2 Instructed Imbalance Energy Charges on Scheduling Coordinators

The Instructed Imbalance Energy charge for ~~Trading Interval t~~ Settlement Period t for Scheduling Coordinator j for Zone x is calculated using the following formula:

$IIEC_j = IGDC_j + ILDC_j + IIDC_j$

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The instructed Generation deviation payment/charge is calculated as follows:

$$IGDCj = \sum_{gi} \frac{G_{gi} * P_i}{HBI}$$

The instructed Load deviation payment/charge is calculated as follows:

$$ILDCj = \sum_{Li} \frac{L_{Li} * P_i}{HBI}$$

The instructed import deviation payment/charge is calculated as follows:

$$IIDCj = \sum_{Ii} \frac{I_{Ii} {*} P_i}{HBI}$$

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D2.3 Replacement Reserve Capacity Dispatch Charge

The Replacement Reserve Capacity Dispatch Charge (RRDC) for Scheduling Coordinator j in Trading Interval t is calculated using the following formula:

$$\cancel{RRDC_j = \left[\frac{Max\left(0, \left\{ \sum_i GenDev_i - \sum_i LoadDev_i + \sum_q ImpDev_q + \sum_q ExpDev_q + E_{UFE\_jk} \right\}\right)}{\sum_j Max\left(0, \left\{ \sum_i GenDev_i - \sum_i LoadDev_i + \sum_q ImpDev_q + \sum_q ExpDev_q + E_{UFE\_jk} \right\}\right)} \right] * RRC}$$

$$RRDC_j = \left[\frac{Max\left(0, \left\{ \sum_i GenDev_i - \sum_i LoadDev_i + \sum_q ImpDev_q + \sum_q ExpDev_q + E_{UFE\_jk} \right\}\right) * ReplObligRatio_{jxt}}{\sum \left(Max\left(0, \left\{ \sum_i GenDev_i - \sum_i LoadDev_i + \sum_q ImpDev_q + \sum_q ExpDev_q + E_{UFE\_jk} \right\}\right) * ReplObligRatio_{jxt} \right)} \right] * RRC$$

If there is Congestion in the ~~Day~~ Day-Ahead Market the ISO will allocate the Replacement Reserve Capacity Dispatch Charges on a Zonal basis. If there is no Congestion in the ~~Day~~ Day-Ahead Market the ISO will allocate the Replacement Reserve Capacity Dispatch Charges on a ISO Control Area-wide basis (irrespective of whether there is Congestion in the ~~Hour~~ Hour-Ahead Markets or not).

D 3.38 $IGDC_j$ - $

The total of instructed Generation deviation payments/charges for Scheduling Coordinator j in Settlement Period t.

D 3.39 $ILDC_j$ - $

The total of instructed Load deviation payments/charges for Scheduling Coordinator j in Settlement Period t.

D 3.40 $IIDC_j$ - $

The total of instructed import deviation payments/charges for Scheduling Coordinator j in Settlement Period t.

D 3.41 G_{gi} - MW

Instructed Energy for Generating Unit g during BEEP Interval i.

D 3.42 L_{Li} - MW

Instructed Energy for Load L during BEEP Interval i.

D 3.43 I_i – MW

Instructed Energy for import I during BEEP Interval i

D 3.44 P_i -- $/MWh

The BEEP Incremental Ex Post Price for BEEP Interval i if the net instructed Energy for resources is positive, or the BEEP decremental EX Post Price for BEEP Interval i if the net instructed Energy for resources is negative.

D 3.45 HBI – Number

The number (2-12) of BEEP Intervals in Settlement Period t.

D 3.46 $ReplObligRatio_{jxt}$ – fraction

$$ReplObligRatio_{jxt} = \frac{ReplOblig_{jxt}}{\sum_j ReplOblig_{jxt}}$$

where:

$ReplOblig_{jxt}$ is the replacement reserve capacity obligation as defined in Appendix C section C3.67.

B. Temporary Changes Respecting Physical Constraints on Schedules

During coupled testing, the ISO did not identify any problems with respect to operations that resulted from Schedules being outside of the physical limits of the units Scheduled. The ISO is, however, concerned about this possibility, especially in combination with "thin" Supplemental Energy and Ancillary Services markets. The ISO is also concerned about the lack of adequate economic incentives against imbalances that may result from staging the sub-hour Settlement Period. At least until there is a direct economic consequence relating to imbalances in each of the sub-hour intervals (*i.e.* sub-hour Settlement Periods), the ISO believes that there is a heightened risk to reliability that must be addressed with a market rule.

Although the Schedules and Bids Protocol (section 4) requires that the minimum and maximum output levels contained in Adjustment Bids must be physically achievable, the ISO Tariff, including the Protocols, does not, in its current version, explicitly require that each Generating Unit's schedule, nor any associated Adjustment Bids, be within the Generating Unit's physically achievable capability. For example, a Unit may schedule to operate at 100 MW in one hour and 1000 MW in the next hour, but be physically incapable of a 900 MW ramp within a single hour, leaving the ISO to manage the deficiency in real time. Importantly, without sub-hour Settlement Periods, the economic signal to schedule realistically is muted by the averaging used for the Hourly Ex Post Price for Imbalance Energy.

Thus, in new Section 24 of the ISO Tariff, the ISO amends the Schedules and Bids Protocol to require Scheduling Coordinators for Generators to schedule and bid within the physical capability of their Generating Units. The change also specifies that Generating Units must be capable of the degree of ramping reflected in any Schedule submitted by a Scheduling Coordinator.

As noted above in regard to the problems with Supplemental Energy, this issue also relates to the duration of the BEEP Dispatch interval and the Hourly Settlement Period not being the same. Thus, Section 24 is also an interim provision. The ISO will seek termination of this interim Section and propose any measures that should be made permanent when a comprehensive ISO Tariff amendment is filed to implement a sub-hour Settlement Period pursuant to the ISO staging plan.

24 TEMPORARY CHANGES RESPECTING PHYSICAL CONSTRAINTS ON SCHEDULES

24.1 Application and Termination

The temporary change, respecting physical constraints on Schedules, set out in Section 24.2 shall continue in effect until such time as the Chief Executive Officer of the ISO issues a Notice of Full-Scale Operations, posted on the ISO Internet "Home Page", at http://www.caiso.com, or such other Internet address as the ISO may publish from time to time, specifying the date on which this Section 24 shall cease to apply, which date shall be not less than seven (7) days after the Notice of Full-Scale Operations is issued.

24.2 Amendment to Schedules and Bids Protocol

SBP 2.3 The Generation section of a Balanced Schedule, and any associated Adjustment Bids, must accurately reflect the physical capability of each Generating Unit identified in the Schedule (including each Generating Unit's ability to ramp from one hour to the next). For example, a 500 MW Generating Unit specified with a ramp rate of 2 MW/min and an operating point of 100 MWh for the current operating hour is not physically capable of generating 300 MWh in the next operating hour. Likewise, Adjustment bids submitted for a Generating Unit, applicable to a particular operating hour, should be physically achievable within the applicable operating hour.

C. Changes to Provisions Respecting System Reliability

As noted above, the ISO has identified the potential risk that the Ancillary Services and Supplemental Energy markets would, at least initially, be "thin" (*i.e.* a market where the ISO has received an insufficient number of Ancillary Services and/or Supplemental Energy bids). Without sufficient Supplemental Energy and Ancillary Services bids, the ISO will not have the ability effectively to balance Generation and Demand on a real time basis.

In the coupled test, the ISO was forced to utilize non-market measures to operate the system reliably. In other words, the ISO had to direct specific Generators to operate, in order to maintain the stability of the system, rather than rely on the market to perform this function.

This issue will be exacerbated in the earliest months after start-up, because of low load and potential Overgeneration, due in large part to the season's large volume of hydro-power, including Regulatory Must-Run Resources as well as the relatively mild temperatures associated with the spring season. Based on the ISO's experience with the coupled testing, and the expectation of even greater periods of Overgeneration as the snow-pack begins to melt, the ISO has determined that additional ISO Tariff changes are necessary to ensure reliable operation.

Some of the changes required to address the problem of a "thin" market for Supplemental Energy are temporary or interim. These temporary measures are described above in part A. There are, in addition, necessary changes to the ISO Tariff, involving Sections 2.3.2.3 and 11.2.4.2, and a corresponding change to the Dispatch Protocol, that are not interim in nature.

First, Section 2.3.2.3 of the ISO Tariff defines, more clearly, the circumstances in which the ISO may set the Administrative Price. The provision as revised clarifies that the Administrative Price will ***not*** be set if the ISO is merely trying to ***prevent*** a System Emergency from occurring, but only if such an emergency actually occurs. A corresponding change is proposed to section 10.2.3, Intervention in Market Operations, of the Dispatch Protocol.

The ISO's ability to instruct a Generating Unit in circumstances in which the ISO considers that a System Emergency is imminent or threatened was already treated in Section 5.6. Section 5.6 will thus be the only applicable section for use when the ISO is acting to prevent a System Emergency.

Second, the ISO is amending Section 11.2.4.2 of the ISO Tariff to clarify that, where the ISO exercises its authority to Dispatch Generating Units, Loads or imports, in circumstances where there is a deficiency of Supplemental Energy bids short of a System Emergency, the concerned Scheduling Coordinators will be paid at the Imbalance Energy Price referenced in Section 11.2.4.1.

This clarification is necessary because, during the coupled testing, Scheduling Coordinators communicated a concern that they would not be paid when responding to an ISO "out of market" instruction short of a System Emergency. In fact, the ISO structure already contemplated that Scheduling Coordinators would be compensated through the Imbalance Energy mechanism for either increasing or decreasing Generation in response to an ISO out-of-market order. This clarification merely eliminates potential confusion.

Notwithstanding that the ISO Tariff already contemplated the Imbalance Price as the appropriate price, the ISO considered whether a different payment would be more appropriate. For example, many utilities charge a high "Emergency" Energy price, sometimes up to 100 mills/kWh. The ISO considered a premium price, but concluded that no change to the ISO Tariff pricing structure is necessary at this time, in particular because a premium price might encourage the Generating Units to withhold bids, awaiting a call "out of market."

The Imbalance Energy Price, in contrast, reflects the value of the Energy to the market and provides no disincentive to Scheduling Coordinators to submit sufficient Supplemental Energy bids and Ancillary Service bids for use by the ISO. Specifically, a Scheduling Coordinator has two choices, as follows.

- It can choose not to submit a Supplemental Energy bid or Ancillary Service bid in any particular hour; however, in doing so it risks being called upon "out of market" at times when the Imbalance Energy Price may be insufficient to cover its incremental or decremental operating costs.

- Alternatively, if the Scheduling Coordinator submits a Supplemental Energy bid or Ancillary Service bid designed to recover its incremental or decremental costs, it can protect itself from uncertainty.

The ISO determined that the Imbalance Energy price currently in the ISO Tariff is, therefore, an acceptable approach that allows the ISO to operate the system reliably, without creating incentives that discourage bidding.

ISO TARIFF AMENDMENTS

2.3.2.3 Intervention in Market Operations. The ISO may intervene in the operation of the Day-Ahead Market, the Hour-Ahead Market or the Real Time Market and set the Administrative Price, if the ISO determines that such intervention is necessary in order to ~~prevent,~~ contain, or correct ~~the~~ a

System Emergency as follows~~:~~.

11.2.4.2 With respect to Regulatory Must-Take and Regulatory Must-Run Generation, and with respect to Generating Units, Loads and imports which have not bid into the Imbalance Energy markets but which have been dispatched by the ISO to avoid an intervention in market operations or to prevent a System Emergency, the ISO shall calculate, account for and settle deviations from the Final Schedule submitted on behalf of each such ~~Generator~~ Generating Unit, Load or import with the relevant Scheduling Coordinator for each Settlement Period for each such Generating Unit, Load or import by way of the Uninstructed Imbalance Energy Charge price as calculated in accordance with Section 11.2.4.1.

DISPATCH PROTOCOL AMENDMENT

DP 10.2.3 Intervention in Market Operations

(a) The ISO may intervene in the operation of the Day-Ahead, Hour-Ahead or Real Time Markets and set the Administrative Price if the ISO determines that such intervention is necessary in order to ~~prevent,~~ contain or correct the System Emergency.

D. Changes in Regard to Overgeneration Management

In its October 30, 1997 Order, the Commission rejected the ISO's Overgeneration Protocol, instructing Scheduling Coordinators to handle Overgeneration. [1] The ISO, however, retains the responsibility to manage Overgeneration in real time.

To date, the Commission has not ruled on the ISO request for rehearing seeking reinstatement of the Overgeneration Protocol. As a result, since the ISO has been awaiting the rehearing, no comprehensive stakeholder process has been undertaken to develop a new Overgeneration Protocol limited to real time operations.

Experience during the coupled test has demonstrated that, at a minimum, the ISO must change certain provisions in the body of the ISO Tariff, and in the Dispatch Protocol, to provide adequate systems and procedures for managing Overgeneration in real time, until the Commission finally rules on the rehearing and pending further changes that may come out of a comprehensive stakeholder process once the rehearing is decided.

Currently, the only systems or procedures available to the ISO to handle Overgeneration are those specified in Section 2.3.4 of the ISO Tariff:

> **2.3.4 Management of Overgeneration Conditions.**
>
> The ISO's management of Overgeneration relates only to real time. Overgeneration in real time will be mitigated by the ISO through the Imbalance Energy market and, to the extent that this is insufficient to resolve the problem, by directing each Scheduling Coordinator to reduce its Generation pro rata based on the product of the total required reduction in Generation and the ratio of its Demand to the total Demand in the ISO Control Area.

This ISO Tariff provision is, in turn, cross-referenced in section DP 8.8 of the Dispatch Protocol.

The problems identified by the ISO are several:

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[2] Note that this deviation is a difference between a forward Market value and a Real Time value. It is not inadvertent energy.

[1] See *Pacific Gas and Electric Company* 81 FERC ¶ 61,122 at 61,525-26 (1997) ("October 30 Order").

- there have been inadequate decremental bids ("decs") in the Supplemental Energy market required for ramps, and for what might otherwise be required in certain instances to remedy Overgeneration;
- the current ISO Tariff procedure provides no mechanism for the market to respond before *pro rata* curtailments are ordered; and
- the current ISO Tariff procedure penalizes all Scheduling Coordinators, rather than those causing the Overgeneration,[2] thereby providing the wrong incentives to Market Participants.[3]

After start-up, the ISO will commence a stakeholder process to consider a comprehensive approach to manage Overgeneration in real time. To meet immediate reliability concerns, however, the ISO is amending its real-time Overgeneration procedures, as follows.

(1) The ISO will first rely on decremental Adjustment Bids and Supplemental Energy bids.

(2) If these bids are insufficient, the ISO will notify Scheduling Coordinators of the amount of Overgeneration and advise the Scheduling Coordinators that the *ex post* price for Imbalance Energy is set to $0/MWh, with periodic updates.

(3) In addition, the ISO will, if necessary, do the following:

(a) attempt to eliminate the Overgeneration by exports of Energy to one or more adjoining Control Areas at no cost or at a negative price;

(b) direct Scheduling Coordinators to reduce Generation or external imports (or increase exports) on the basis of each Scheduling Coordinator's scheduled Demand *pro rata* to total Scheduled Demand; and, finally,

(c) order mandatory reductions in the output of specific Generating Units and monitor the response of such units.[4]

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[2] The ISO does not have the ability, in real time, to determine which Scheduling Coordinator is deviating from its Schedule. This information is only known when all meter data is collected – monthly.

[3] This problem is exacerbated when Dispatch periods are not the same as Settlement Periods. Scheduling Coordinators wishing to avoid Imbalance Energy payments will begin ramps ahead of the hour, increasing Overgeneration.

[4] Some Scheduling Coordinators raised concerns about the equity of ordering mandatory reductions of specific units. This is a measure of last resort, necessary when the directive for *pro rata* reductions has not relieved the Overgeneration and immediate, verifiable action is

The operator will have the discretion, if necessary to avoid a System Emergency, to skip one or more of these steps. Any costs incurred in eliminating Overgeneration will be borne by Scheduling Coordinators through the Imbalance Energy charge – thus assigning the costs only to Scheduling Coordinators whose Generating Units were over-producing or whose Loads were under-consuming, relative to their respective Final Schedules.

These changes are contained in the amended Section 2.3.4 of the ISO Tariff and section 8.8 of the Dispatch Protocol.

As noted above, these changes are to continue in effect only until the Commission acts upon the application for rehearing of the ISO's rejected Overgeneration Protocol and until a comprehensive stakeholder process can be completed that looks at long-term solutions for managing Overgeneration in real time. For example, a number of Scheduling Coordinators favor allowing negative prices. That proposal will need to be explored in the comprehensive review. Also, stakeholders have expressed a concern that any discretionary actions by the ISO be subject to review. The ISO will work with stakeholders to develop a proper reporting and monitoring system that gives Market Participants confidence that Overgeneration is being prudently managed.

ISO TARIFF AMENDMENTS

2.3.4 Management of Overgeneration Conditions

The ISO's management of Overgeneration relates only to real time. Overgeneration in real time will be mitigated by the ISO as follows; provided that the ISO operator will have the discretion, if necessary to avoid a system emergency, to eliminate one or more of the following steps.~~through the Imbalance Energy market and, to the extent that this is insuffucient to resolve the problem, by directing each Scheduling Coordinator to reduce its Generation pro rata based on the product of the total required reduction in Generation and the ratio of its Demand to the total Demand in the ISO Controlled Area.~~

2.3.4.1 Commencing one hour prior to the start of the Settlement Period, the ISO will, based on available Adjustment Bids, Supplemental Energy bids and Ancillary Service Energy bids, issue Dispatch instructions to Scheduling Coordinators to reduce Generation and imports for the next operating hour.

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required. The ISO would have this authority in any event under Section 5.6, since the intent is to use it to prevent a System Emergency.

2.3.4.2 To the extent that there are insufficient decremental Energy bids available for the operating hour to fully mitigate the Overgeneration condition, the ISO will set the Ex Post Price for that operating hour at $0/MWh and notify Scheduling Coordinators of the projected amount of Overgeneration to be mitigated in that hour.

2.3.4.3 In addition to the action taken under 2.3.4.2, the ISO may, if it considers it necessary to maintain the reliable operation of the ISO Control Area, offer Energy for sale on behalf of Scheduling Coordinators to adjacent Control Area operators at $0/MWh or, if the ISO considers it necessary, at a price established by the ISO on behalf of Scheduling Coordinators, to be paid to adjacent Control Area operators.

2.3.4.4 To the extent that the steps described in Sections 2.3.4.1 through 2.3.4.3 fail to mitigate Overgeneration, the ISO will instruct Scheduling Coordinators to reduce either Generation, or imports, or both. The amount of the reduction for each Scheduling Coordinator will be calculated pro rata based on the product of the total required reduction in Generation and imports (or increase in exports) and the ratio of its Demand to the total Demand in the ISO Control Area.

2.3.4.5 To the extent that the above steps fail to fully mitigate the Overgeneration, the ISO will issue mandatory Dispatch instructions for specific reductions in Generating Unit output and external imports and all relevant Scheduling Coordinators shall be obligated to comply with such Dispatch instructions.

2.3.4.6 Any costs incurred by the ISO in implementing Section 2.3.4.3 shall be reimbursed to the ISO by Scheduling Coordinators based upon the extent to which they supplied Energy, in metered amounts, greater than the Generation and imports scheduled in their Final Schedules and consumed Energy, in metered amounts, less than the Demand scheduled in their Final Schedules, as a proportion of the total amount of such excess or shortfall among all Scheduling Coordinators.

DISPATCH PROTOCOL AMENDMENT

DP 8.8 Real Time Management of Overgeneration Conditions

In the event that Overgeneration conditions occur during real time, the ISO will direct the SCs to ~~curtail Generation in accordance with~~

take the steps described in Section 2.3.4 of the ISO Tariff and SCs shall implement ~~such~~ ISO directions without delay.

E. Changes to Give Load an Implicit Priority in Congestion Management

During the coupled test, there were some hours in which Congestion occurred. During these hours, the ISO Congestion Management software ("CONG") curtailed Load and Generation due to inadequate Adjustment Bids. In examining the test results, the ISO determined that CONG curtailed Load at the same relative priority as Generation and external exports.

Load is relatively less flexible than Generation. Thus, even though CONG ***assumes*** Load will be curtailed as per the Final Adjusted Schedule, in fact, it is more likely that Load will not be curtailed and add to real time imbalances. The ISO operators need accurate information to operate the system reliably. When curtailments are necessary, the ISO believes Generation is likely to be increased rather than Loaded curtailed and that CONG should recognize that assumption.

The ISO is, therefore, revising the description and use provisions for Adjustment Bids, in both the Schedules and Bids Protocol and in the Scheduling Protocol, to alter the relative priority of the curtailments to reflect what, in all likelihood, will actually occur.

The CONG software assigns implicit Adjustment Bids to all Load and Generation in order to perform the congestion management. To give Load a relatively higher priority than Generation, the CONG software assigns an implicit higher Adjustment Bid to Loads that are submitted without Adjustment Bids (*i.e.* "price-takers") than is assigned to Generation submitted without Adjustment Bids. Using this approach will, however, require modification of several other values and ranges of Adjustment Bids.

The software change to give Load a higher relative priority is expected to be in place by the ISO Operations Date and the Schedules and Bids Protocol and the Scheduling Protocol must be revised to conform to the new software. The amendment does, however, provide for the current Adjustment Bid values to remain in place if the software is not operational at start-up and for seven days' notice before the amendments come into effect. Scheduling Coordinators need to be aware of these changes, since the internal changes affect several of the values and ranges that Scheduling Coordinators must rely upon to protect, and properly prioritize, their scheduled uses. Market Participants will be informed of these changes prior to the start of the market.

Finally, it should be noted that the changes in this part E are not limited to the changes necessary to implement the prioritization of Load. Certain other blacklined changes are also included. These are non-substantive changes to clarify previous filings regarding the treatment of Regulatory Must-Take and Regulatory Must-Run Resources and Existing Contracts and the changes made *infra* regarding the Default Usage Charge.

SCHEDULES AND BIDS PROTOCOL AMENDMENTS

SBP 3.4 Validation of Existing Contract Schedules

Each Schedule submitted to the ISO by a SC representing a rights holder to an Existing Contract must include a valid contract reference number in accordance with SBP 3.3. If the Schedule includes an Inter-Scheduling Coordinator Trade, only one of the SCs should submit a contract reference number. If a match of the Schedule's contract reference number is found in the ISO's database and the Schedule is consistent with the instructions submitted previously by the Responsible PTO, the Schedule will be implemented in accordance with the instructions. If a match of the Schedule's contract reference number cannot be found in the ISO's database, or if both SCs, or neither SC, which is a party to an Inter-Scheduling Coordinator Trade submits a contract reference number, the ISO will contact the SC and indicate the nature of the problem. The ISO will assist the SC, within reason, in resolving the problem so that the SC is able to submit the Schedule successfully as soon as possible within the timing requirements of the SP. If the SC uses a contract reference number for which the Responsible PTO has not reserved transmission capacity on a particular path (i.e., the contract reference number cannot be found in the ISO's scheduling applications table of contract reference numbers), the scheduled use will be treated as a new firm use~~s~~ with a $0/MWh Adjustment Bid.

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SBP 4.6 Use of Adjustment Bids to Establish Priorities

In addition to being used to establish the value each Scheduling Coordinator places on the use of Congested Inter-Zonal Interfaces, Adjustment Bids are also used by the ISO to establish priorities associated with transmission service under Existing Contracts and priorities associated with certain Reliability Must-Run Generation, Eligible Regulatory Must-Take Generation and Eligible Regulatory Must-Run Generation that enjoyed such priorities prior to the ISO Operations Date. To accomplish this, certain Adjustment Bids and ranges of Adjustment Bids have been reserved for use in establishing relative priorities. If the Congestion Management software is not capable of supporting the particular Adjustment Bid values and ranges upon the ISO Operations Date, the ISO will establish alternate values and ranges, which may be changed by the ISO with seven (7) days' prior notice to Scheduling Coordinators, by way of a notice posted on the ISO Internet "Home Page", at http://www.caiso.com, or such other Internet address as the ISO may publish from time to time. ~~Any Adjustment Bid (other than an Adjustment Bid related to Existing Contracts, Reliability Must-Run Generation, Eligible Regulatory Must-Take Generation or Eligible Regulatory Must-Run Generation) which exceeds the default Usage Charge, will be treated as if the Adjustment Bid was equal to the default Usage Charge (see description below regarding the Congestion Management software treatment of an implicitly assigned negative value for default Usage Charge).~~ Otherwise, t~~T~~he values and ranges for Adjustment Bids to be submitted by Scheduling Coordinators or Adjustment Bids implicitly assigned by the Congestion Management software for these various purposes are as follows:

Adjustment Bid Value/Range <u>$/MWh</u>	**<u>Use</u>**
~~2,000~~10,000	Adjustment Bid value implicitly assigned by the Congestion Management software to Inter-Scheduling Coordinator Trade exports with a valid contract reference number for the amount of the Inter-Scheduling Coordinator Trade equal to or less than the MW amount specified in the Existing Contract (i.e., specified in the "Contract MW" field of the schedule template). Usage Charges are not calculated for these scheduled uses, except for any quantity of Energy scheduled in excess of the MW amount specified in the Existing Contract (i.e., specified in the "Contract MW" field of the schedule template) which is treated as a new firm use of ISO transmission service which the Congestion Management software implicitly values at the Adjustment Bid price ~~of 1.4 x default Usage Charge~~and for which Usage Charges may be accounted to the Scheduling Coordinator as a price-taker of ISO transmission service.

~~1,900~~9,000 to ~~2,000~~10,000	Adjustment Bid range available for Demand and external export schedules using Existing Contract rights with a valid contract reference number. Usage Charges are not calculated for these scheduled uses except for quantities of Energy scheduled in excess of the MW amount specified in the Existing Contract (which is treated as a new firm use of ISO transmission service ~~and~~ which the Congestion Management software implicitly values ~~the additional transmission service~~ at the Adjustment Bid price within this range) and for which Usage Charges may be accounted to the Scheduling Coordinator as a price-taker of ISO transmission service.
4,000	Adjustment Bid value implicitly assigned by the Congestion Management software to protect Day-Ahead commitments of new firm uses in the Hour-Ahead Market (specifically with respect to schedules of Demand and external exports).
~~1.4 x default Usage Charge~~1,500	Adjustment Bid value implicitly assigned by the Congestion Management software to Inter-Scheduling Coordinator Trade exports using new firm uses of ISO transmission service. Usage Charges are calculated for these scheduled uses.
700	Adjustment Bid value implicitly assigned by the Congestion Management software for Demand schedules of new firm uses when no Adjustment Bid is provided (i.e., a "price-taker"). Usage Charges are calculated for these scheduled uses. The Congestion Management software also uses this value to extend the lower megawatt end of submitted Adjustment Bids for Demand schedules to zero megawatts.

~~default Usage Charge~~600	Adjustment Bid value implicitly assigned by the Congestion Management software for ~~Demand and~~ external export schedules of new firm uses when no Adjustment Bid is provided (i.e., a "price-taker") or to extend the lower megawatt end of the Adjustment Bid to zero megawatts. This is also the Adjustment Bid value implicitly used by the Congestion Management software to extend the upper megawatt end of a Generator's Adjustment Bid to the Generator's physical maximum limit (for external import schedules, and for external export schedules, the upper megawatt end of the Adjustment Bid is treated as the "physical" maximum limit and, as such, is not extended). Usage Charges are calculated for these scheduled uses.
0.01 to ~~< default Usage Charge~~250	Adjustment Bid range available for scheduling new firm uses of ISO transmission service bid as potential "price-makers." The high-end value of this range is initially set at $250/MWh, but can be increased by the ISO to $500/MWh, upon seven days notice. Usage Charges are calculated for these scheduled uses. This is the "normal" economic range for Adjustment Bids. The default Usage Charge is calculated by the Congestion Management software to fall within this range in accordance with Section 7.3.1.3 of the ISO Tariff.
0.001 to < 0.01	Adjustment Bid range available for scheduling the use of conditional firm Existing Contract rights. Although available for Existing Contract use, this range is not protected from Usage Charges since the charges would be calculated in fractions of dollars (e.g., 100 MW at $0.01/MWh produces a $1.00 charge). A contract reference number is not used for

	scheduling use of conditional firm Existing Contract rights.
0	Adjustment Bid value available for scheduling either new firm uses of ISO transmission service or uses of Existing Contract rights and expressing a zero dollar value for adjustments. This is the Adjustment Bid value implicitly assigned by the Congestion Management software for a Generator or external import that is specified with a priority type or contract reference number that cannot be verified in the ISO's scheduling system and submitted with a negative Adjustment Bid outside of the range reserved for Existing Contracts (i.e., -$~~1,900~~ 9,000 to -$~~2,000~~10,000), Eligible Regulatory Must-Run, Eligible Regulatory Must-Take, and Reliability Must-Run (i.e., -$~~10,000~~30,000).
~~-default Usage Charge~~600	Adjustment Bid value implicitly assigned by the Congestion Management software for Generation and external import schedules of new firm uses when no Adjustment Bid is provided (i.e., a "price-taker") or to extend the lower megawatt end of a Generator's Adjustment Bid to the Generator's physical minimum limit. This is also the Adjustment Bid value used by the Congestion Management software to extend the lower megawatt end of an external import's Adjustment Bid to zero megawatts. If a Scheduling Coordinator is relying partially on Existing Contract rights for an external import or Generator schedule bid and wishes to be a "price-taker" for the balance not covered by those rights, it ~~should~~ must explicitly submit this value as its Adjustment Bid for the balance.

~~-1.4 x default Usage Charge~~1,500	Adjustment Bid value implicitly assigned by the Congestion Management software to Inter-Scheduling Coordinator Trade imports using new firm uses of ISO transmission service. Usage Charges are calculated for these scheduled uses.
-4,000	Adjustment Bid value implicitly assigned by the Congestion Management software to protect Day-Ahead commitments of new firm uses in the Hour-Ahead Market (specifically with respect to schedules of Generation and external imports).
-~~1,900~~9,000 to -~~2,000~~10,000	Adjustment Bid range available for scheduling Generation and external imports using Existing Contract rights with a valid contract reference number. Usage Charges are not calculated for these scheduled uses except for quantities of Energy scheduled in excess of the MW amount specified in the Existing Contract (which is treated as a new firm use of ISO transmission service and values the additional transmission service at the Adjustment Bid price within this range) and for which Usage Charges may be accounted to the Scheduling Coordinator as a price-taker of ISO transmission service. An Adjustment Bid, for an Existing Contract use, submitted with a price for the first (or single) segment outside of this range will be treated by the Congestion Management software as a zero ~~value~~ price bid.
-~~2,000~~10,000	Adjustment Bid value implicitly assigned by the Congestion Management software to Inter-Scheduling Coordinator Trade imports with a valid contract reference number for the amount of the Inter-Scheduling Coordinator Trade equal to or less than the MW amount specified in the Existing Contract. Usage Charges are not calculated

	for these scheduled uses except for ~~any quantity of Energy scheduled in excess of the MW amount specified in the Existing Contract which is treated as a new firm use of ISO transmission service which the Congestion Management software values at the Adjustment Bid price of -1.4 x default Usage Charge~~quantities of Energy scheduled in excess of the amount specified in the "Contract MW" field of the scheduling template (for which the amount is treated as a new firm use of ISO transmission service and values the additional transmission service at the Adjustment Bid price within this range) and for which Usage Charges are accounted to the Scheduling Coordinator as a price-taker for ISO transmission service.
-~~10,000~~30,000	Adjustment Bid value available for scheduling priority types of Reliability Must-Run Generation, Eligible Regulatory Must-Take Generation and Eligible Regulatory Must-Run Generation only. Usage Charges are calculated for these scheduled uses. An Adjustment Bid, for ~~a~~ such priority type use, submitted with a price for the first (or single) segment less than this value, will be treated by the Congestion Management software as a zero value bid~~(e.g., an Adjustment Bid of -$9,998/MWh will be treated as a zero value bid)~~.

SCHEDULING PROTOCOL AMENDMENT

SP 7.2.2 Prioritization of Transmission Uses

The following rules are designed to enable the ISO to honor Existing Contracts in accordance with Sections 2.4.3 and 2.4.4 of the ISO Tariff, except as may be limited by the operation of SP 7.4. Regardless of the success of the application of such rules, it is intended that the rights under Existing Contracts will be honored as contemplated by the ISO Tariff except as may be limited by the operation of SP 7.4. In each of the categories described in SP 7.2.1, the terms and conditions of service may differ among transmission contracts. These differences will be described by each Responsible PTO in the instructions submitted to the ISO in advance of the scheduling process in accordance with the SBP. In addition, Generation, Inter-Scheduling Coordinator Trade imports or external imports in one Zone must be matched by an equal magnitude of Demand, Inter-Scheduling Coordinator Trade exports or external exports in an adjacent Zone (see SP 7.2.3 for a summary of allowable linkages). Scheduling and curtailment priorities associated with each category will be defined by SCs through the use of Adjustment Bids submitted as part of their Schedules as described in the following (see the SBP for a more general description of the use of Adjustment Bids to not only establish priorities within Existing Contracts, but also to establish priorities for Reliability Must-Run Generation , Eligible Regulatory Must-Take Generation and Eligible Regulatory Must-Run Generation):

(a) Transmission capacity for Schedules will be made available to holders of firm Existing Rights and firm Non-Converted Rights in accordance with this SP and the terms and conditions of their Existing Contracts. In the event that the firm uses of these rights must be curtailed, they will be curtailed on the basis of "high priced Adjustment Bids". So as not to be curtailed before any other scheduled use of Congested Inter-Zonal Interface capacity, these high priced Adjustment Bids must fall within a range to be specified by the ISO (for example, a difference of +$~~1,900~~9,000/ MWh to +$~~2,000~~10,000/ MWh for Demand or external exports and a difference of -$ ~~1,900~~9,000/ MWh to -$ ~~2,000~~10,000/ MWh for Generation or external imports). This range will be reserved strictly for use in association with the prioritization of firm Existing Rights and firm Non-Converted Rights to use available Inter-Zonal Interface transmission capacity. These high priced Adjustment Bids are only for the ISO's use, in the context of Congestion Management, in recognizing the various levels of priority that may exist among the scheduled uses of firm transmission service. These high priced Adjustment Bids will not affect any other rights under Existing Contracts. To the extent that the MW amount exceeds the MW amount specified in the Existing Contract, the excess scheduled amount will be treated as a new firm use of ISO transmission services as described in (b) below. Note that, in some instances, for a particular Inter-Zonal Interface, there may be multiple SCs submitting Schedules under several different Existing Contracts on behalf of several Existing Contract rights holders. In these circumstances, and to the extent the rights holders desire to coordinate the prioritization of their firm uses of the Inter-Zonal Interface (i.e., attribute high priced Adjustment Bids, within the specified range, to each Schedule), their SCs will make the arrangements among themselves ahead of the ISO's scheduling process. In the absence of an Adjustment Bid, the ISO will treat the scheduled use of transmission service as a "price-taker" of ISO transmission service subject to Usage Charges.

F. Changes to the Default Usage Charge

Amendment No. 4 noted that the ISO had identified a potential gaming scenario and identified a solution whereby a default Usage Charge ("DUC") would be set at the top of the range of economic Adjustment Bids. Amendment No. 4 also provided for the DUC to be set by the ISO from time to time in a range between $200/MWh and $500/MWh. The ISO noted that the charge was being fixed initially at $250/MWh.

As also noted in the Amendment No. 4 filing, Scheduling Coordinators have expressed a strong preference that the DUC be set as low as possible, to avoid imposing unnecessary penalties on Scheduling Coordinators who must be "price takers" in Congestion Management because their Schedules are primarily composed of Inter-Scheduling Coordinator Trades. As the ISO considered the changes included in this filing, it became clear that the Scheduling Coordinators remain opposed to high DUCs.

That opposition must be balanced, however, with the need to avoid discouraging Adjustment Bids. Because the DUC must be equal to the top of the economic Adjustment Bid range to avoid the earlier-identified gaming opportunity, it is important not to set the DUC so low that it discourages Adjustment Bids.

In response to further discussions on this issue between the ISO and Market Participants concerned about the possibly punitive effect of a high DUC, the ISO has developed a further change to Section 7.3.1.3 of the ISO Tariff and to the Scheduling Protocol. The change would lower the floor of the DUC, and afford the ISO the necessary flexibility to balance, on a day-to-day basis, the concerns of Scheduling Coordinators with the need to avoid disincentives to Scheduling Coordinators to submit Adjustment Bids.

The ISO Board, after long discussion, concluded that ISO management should have the flexibility to set the applicable floor and ceiling within certain "absolute" amounts, namely an absolute floor of $0 and an absolute ceiling of $500. Initially, ISO management intends to set the floor at the very low level of $30 and the ceiling at $250.

The ISO Board also directed management to include, in this ISO Tariff amendment, a further provision, giving the ISO management the ability, when the required software is installed, to have a "floating" DUC, calculated in most instances by adding a pre-set "adder" (an amount between $0 and $99) to the highest incremental bid ("inc") used less the applicable decremental bid ("dec") used. In all cases where there are insufficient decremental bids or no decremental bids, the applicable dec will be zero. The values for the floor, ceiling and adder will be adjusted as required, within the absolute limits, with one day's notice to vary the floor and the adder, and seven days' notice to vary the ceiling.

The one day notice allows management to set a low floor initially, to soften the impact of early Scheduling Coordinator mistakes, knowing that it can raise the floor quickly if it concludes that Adjustment Bids are being discouraged. The floor and adder, as provided in the amended ISO Tariff provision, could be changed with notice to the Scheduling Coordinators along with Final Revised Schedules at the close of the Day-Ahead Market, for applicability to the following Day-Ahead Market. As indicated, a seven-day advance notice would still be required to change the floating ceiling, again within the absolute limit of $500. Such a change would be made if the ISO concluded that the level of the default Usage Charge may be discouraging Adjustment Bids.

The amendment also provides that, if the new software necessary to implement the "floating" DUC arrangement is not operational by start-up, the ISO management will establish a "fixed" DUC, changeable on one day's notice. Once available, the ISO will implement the software for the "floating" DUC arrangement, after giving Scheduling Coordinators seven days' notice.

Because the concept of the default Usage Charge is complex, the ISO Board asked management to provide a simple description of how the DUC will be calculated. Although it is somewhat difficult to describe the linear optimization algorithm that is used in the Congestion Management process in a simple manner, the following description will serve as a good approximation of the process.

The ISO's Congestion Management program (CONG) calculates a Usage Charge for a transmission path based on evaluating pairs of Adjustment Bids in each Scheduling Coordinator's portfolio. Adjustment Bids are voluntary adjustments that a Scheduling Coordinator can make to the resources in its portfolio. ***There is no matching of bids between Scheduling Coordinator portfolios in this process. There is also no requirement that a Scheduling Coordinator submit bids only in pairs.*** For example, a Scheduling Coordinator could submit a decremental bid on a fully loaded Generator, to indicate its willingness to decrement, and not have a matching incremental bid.

If there are insufficient pairs of Adjustment Bids to resolve Congestion, then all that will be left is Scheduling Coordinators that have unused incremental or decremental Adjustment Bids. At that point, CONG will deem that it has "run out of Adjustment Bids" even though there may be unused and unmatched bids remaining. The market design does ***not*** allow the ISO to match the decs of one

Scheduling Coordinator with the incs of another Scheduling Coordinator.

At this point, the default Usage Charge applies. CONG will still calculate the most economical way to continue to reduce transmission path usage. For example, if there is an unused incremental Adjustment Bid that is the most economical, after all the pairs are exhausted, CONG will exercise the unused incremental Adjustment Bid and decrement resources *pro rata* ***in that Scheduling Coordinator portfolio*** in order to keep it in balance. A similar action takes place with the unused decremental Adjustment Bids.

After all this takes place, CONG will take the highest incremental Adjustment Bid that was actually ***used*** as the basis for the DUC calculation. The lack of adequate Adjustment Bids signals, however, a market failure. Theoretically, setting a default Usage Charge equal to the last of a set of inadequate bids fails to send the proper signal to the market that additional Adjustment Bids are required (since clearly that price was inadequate to attract a sufficient amount of Adjustment Bids). For that reason, the Board has directed management to provide for an “adder”, as described above, that may be applied to the highest incremental Adjustment Bid to provide additional incentive for Scheduling Coordinators to supply Adjustment Bids. As indicated, the adder will initially be set at $0/MWh, but this number may be changed by the ISO, on one day's notice, as experience dictates.

Under these initial arrangements, calculation of the DUC will generally be as illustrated in the chart below.

		Decremental Adjustment Bids		
		Sufficient Decs	**Insufficient Decs**	**No Decs**
Incremental adjustment Bids	**Sufficient Incs**	No DUC – actual Usage Charge is incs minus decs, but always ≤ $250	highest inc minus $0 plus $ adder (initially $0), but always ≤ $250 and ≥ $30	highest inc minus $0 plus $ adder, but always ≤ $250 and ≥ $30
	Insufficient Incs	highest inc minus lowest dec plus $ adder, but always ≤ $250 and ≥ $30	highest inc minus $0 plus $ adder, but always ≤ $250 and ≥ $30	highest inc minus $0 plus $ adder, but always ≤ $250 and ≥ $30
	No Incs	$250 minus lowest dec plus $ adder, but always ≤ $250 and ≥ $30	$250 minus $0 plus $ adder, but always ≤ $250 and ≥ $30	$250 minus $0 plus $ adder, but always ≤ $250 and ≥ $30

ISO TARIFF AMENDMENTS

7.3.1.3 **Default Usage Charge.** If inadequate or unusable Adjustment Bids have been submitted to the ISO to enable the ISO's Congestion Management to schedule Inter-Zonal Interface capacity on an economic basis, then the ISO will calculate and impose a default Usage Charge, in accordance with Sections 7.3.1.3.1 through 7.3.1.3.4. ~~assume a decremental bid of zero and an incremental bid equal to $250/MWh for the relevant Settlement Period. The ISO may change the default Usage Charge either incrementally or decrementally at any time by giving seven days' notice published on WEnet and the ISO's "Home Page", but will not set a default Usage Charge lower than $200/MWh or higher than $500/MWh.~~

7.3.1.3.1 The default Usage Charge will be calculated within a range having an absolute floor of \$0/MWh and an absolute ceiling of \$500/MWh; provided that the ISO may vary the floor within the absolute limits, with day-prior notice (e.g., applicable to next day's Day-Ahead Market) to Scheduling Coordinators, and vary the ceiling within the absolute limits, with at least seven (7) days notice to Scheduling Coordinators.

7.3.1.3.2 The default Usage Charge will be calculated, in accordance with this Section 7.3.1.3, by applying a pre-set adder, ranging from \$0/MWh to \$99/MWh, to the highest incremental Adjustment Bid used, less the applicable decremental Adjustment Bid used; provided that in all cases where there are insufficient decremental Adjustment Bids or no decremental Adjustment Bids available, in the exercise of mitigating Congestion, the applicable decremental price will be set equal to \$0/MWh; provided, further, that the ISO may vary the pre-set adder with day-prior notice to Scheduling Coordinators (*e.g.*, applicable to next day's Day-Ahead Market).

7.3.1.3.3 Upon the ISO Operations Date, and until such time as the ISO determines otherwise, the ceiling price for the default Usage Charge will be set at \$250/MWh; the floor price for the default Usage Charge will be set at \$30/MWh; and the pre-set adder that is to be applied in accordance with section 7.3.1.3.2 will be set at \$0/MWh.

7.3.1.3.4 The ISO will develop and implement a procedure for posting default Usage Charges on the WEnet or ISO Home Page.

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7.3.1.3.5 If the Congestion Management software is not capable of calculating the default Usage Charge upon the ISO Operations Date in accordance with Sections 7.3.1.3.1 through 7.3.1.3.4, the ISO will establish a fixed default Usage Charge within the absolute limits of \$0/MWh and \$500/MWh, which may be changed by the ISO with day-prior notice. Initially, the default Usage Charge would be capped at \$100/MWh. As soon as tested and available, the ISO will implement the Congestion Management software to calculate the default Usage Charge in accordance with Sections 7.3.1.3.1 through 7.3.1.3.4 after giving at least seven (7) days notice to Scheduling Coordinators, by way of a notice posted on the ISO Internet "Home Page" at http://www.caiso.com or such other Internet address as the ISO may publish from time to time.

SCHEDULING PROTOCOL AMENDMENTS

SP 10.3 Congestion Management Pricing

(b) The ISO will determine the prices for the use of Congested Inter-Zonal Interfaces using the Adjustment Bids. The ISO will collect Usage Charges from SCs for their Scheduled use of Congested Inter-Zonal Interfaces. If Adjustment Bids are exhausted and Schedules are adjusted pro rata, the ISO will apply a default Usage Charge ~~set at $250. The ISO may change the default Usage Charge either incrementally or decrementally at any time by giving seven days' notice published on WEnet and the ISO's "Home Page", but will not set a default Usage Charge lower than $200/MWh or higher than $500/MWh.~~calculated in accordance with Section 7.3.1.3 of the ISO Tariff.

G. Changes to Reliability Must-Run Settlements and Scheduling

The ISO, in conformity with the Commission's October 30 Order, will call upon Reliability Must-Run Generation ("RMR") after receipt of the initial Preferred Schedules in the Day-Ahead Market. Typically, the Scheduling Coordinator for a RMR unit would reflect the ISO's call on the RMR unit by revising its initial Preferred Schedule or changing its Schedule in the Hour-Ahead Market.

Most RMR units will, however, be scheduled through the PX, at least initially. The PX cannot adjust its initial Preferred Schedule in the Day-Ahead Market, nor can it schedule in the Hour-Ahead Market until implementation of its staging plan.

In order to deal with these constraints, the current ISO Tariff and Protocols provide for RMR units to be dispatched, and to provide reliability services, while making provisions to handle the minimum Energy required for these RMR units to be effective. An economic ranking of Day-Ahead and Hour-Ahead decremental bids is used by the ISO to lower existing Generation schedules in other areas to accommodate the minimum RMR Energy. Participating Transmission Owners (PTOs) pay for RMR Dispatch, but they are credited for the market value of the Energy, *i.e.*, the decremental bid Settlements.

However, through the ISO coupled testing, two problems were identified with the existing ISO Settlements and Billing Protocol, as follows.

- **RMR units may not be able to comply with RMR Dispatch instructions, or may not be able to do so in a timely manner.** The Settlements and Billing Protocol currently provides for PTO credits for RMRs based on instructed performance as opposed to actual performance. The ISO is, therefore, changing Appendix B of the Settlements and Billing Protocol to credit PTOs based on actual Generation output.

- **The ISO may not decrement other units to accommodate RMR Energy in real time.:** Due to timing and other operational constraints, ISO operators may request RMR units to provide additional Energy without instructing decremental Energy from another unit (while taking alternative actions to prevent Overgeneration conditions from developing). Where the ISO calls on RMR units in real time and does not decrement other units, the ISO proposes to credit PTOs the Energy provided at the Uninstructed Imbalance Energy Price and is, therefore, amending Appendix H of the Settlements and Billing Protocol to accomplish this.

Finally, an additional change has been made to reflect the fact that the standard arrangement for notifying Scheduling Coordinators for RMR Generation one day in advance of the Trading Day is not appropriate for RMR units with longer lead times. To deal with this, an amendment has been made to SP 3.2.6.1 of the Scheduling Protocol.

SETTLEMENTS AND BILLING PROTOCOL, APPENDIX B AMENDMENTS

B 2.3 Reliability Must-Run Generation

When it becomes necessary for the ISO to request an increase in the output of a Scheduling Coordinator's Reliability Must-Run Generating Unit i in a Zone under a Reliability Must-Run Contract, the ISO will pay the Scheduling Coordinator. The amount that the ISO pays the Scheduling Coordinator j is the Energy weighted average price derived from the Day-Ahead and/or Hour-Ahead Adjustment Bids for all Generating Units whose Scheduled output is decreased under B 2.2 multiplied by the quantity of Energy requested under the Reliability Must-Run Contract and adjusted for any amounts not delivered. The formula for calculating the payment to Scheduling Coordinator j for each Trading Interval$_t$ during which the Reliability Must-Run Unit i is requested to increase its output is:

$$\cancel{PayRMR_{ijt} = \left(\frac{\sum_{ij} ChargeTI_{ijt}}{\sum_{bij} \Delta dec_{bij}} \right) * RMR\Delta inc_{bijt}}$$

$$PayRMR_{ijt} = \left(\frac{\sum_{ij} ChargeTI_{ijt}}{\sum_{bij} \Delta dec_{bij}} \right) * RMR\Delta inc_{ijt} - [\ (RMR\Delta inc_{ijt} - RMRact_{ijt}) * P_{xt}\ ]$$

In this formula, the value of $RMRact_{ijt}$ shall not be greater than the value of $RMR\Delta inc_{ijt}$.

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B 3.10 PayRMR$_{ijt}$ - $

The payment for Scheduling Coordinator j whose Reliability Must-Run Unit i has been increased in Trading Interval t of the Trading Day.

B 3.10.1 RMRact$_{ijt}$ – MW

The actual Energy Delivered by Reliability Must-Run Unit i of Scheduling Coordinator j in Trading Interval t pursuant to the ISO's request.

B 3.10.2 P$_{xt}$ - $/MWh

The zonal Hourly Ex Post Price, for Uninstructed Imbalance Energy, for Trading Interval t in Zone x.

SETTLEMENT AND BILLING PROTOCOL, APPENDIX H AMENDMENTS

H 2 Calculation of Payments and Charges

H 2.1 Reliability Must-Run Payments.

Invoices submitted by Reliability Must-Run Owners to the ISO must be calculated as follows:

(a) *Agreement A*:

The Reliability Must-Run Payment under Agreement A for each month for each Owner shall be the total of the payments for that month for each Reliability Must-Run Unit owned by the Owner to which the Conditions of Must-Run Agreement A apply calculated in accordance with those Conditions. The Agreement A payment for Reliability Must-Run Owner o for Reliability Must-Run Unit u for month m shall be calculated as follows:

$$
\begin{aligned}
RMR\ Pay\ A_{uom} = & \sum_{m} \left[\left(E_{uot} * RPR_{uot} \right) + \left(EM_{uot} * ER_{uot} \right) + \left(E_{uot} * HVO\ \&\ M_{uot} \right) + \left(SCAC_{uot} \right) \right] \\
& + HOF_{uom} + SUFC_{uom} + SUPC_{uom} + OSUC_{uom} \\
& \cancel{+ \sum_{m} \left[AGC_{uot} + SR_{uot} + NSR_{uot} + RR_{uot} + VS_{uot} + ASPDP_{uot} \right]} \\
& - \sum_{m} \left[EA_{uot} * SCP_{uot} \right] - \sum_{m} \left[SCASCP_{uot} \right] - \sum_{m} \left[SCASEP_{uot} \right] - \sum_{m} \left[ER_{uot} * P_{xuot} \right]
\end{aligned}
$$

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$$
\begin{aligned}
RMR\ Pay\ A_{uom} = \sum_{m} & [(E_{uot} * RPR_{uot}) + (EM_{uot} * ER_{uot}) + (E_{uot} * HVO\&M_{uot}) + (SCAC_{uot})] \\
& + HOF_{uom} + SUFC_{uom} + SUPC_{uom} + OSUC_{uom} \\
& + \sum_{m} [AGC_{uot} + SR_{uot} + NSR_{uot} + RR_{uot} + VS_{uot} + ASPDP_{uot}] \\
& - \sum_{m} [EA_{uot} * SCP_{uot}] - \sum_{m} [SCASCP_{uot}] - \sum_{m} [SCASEP_{uot}] - \sum_{m} [ER_{uot} * P_{xuot}] \\
& + \sum_{m} [(ER_{uot} - E_{uot}) * P_{xuot}]
\end{aligned}
$$

The total payment to each Owner for Reliability Must-Run services under Agreement A for a given month shall be calculated by summing all the payments for the month for the Reliability Must-Run Units owned by the Owner to which Agreement A applies. The payment for Owner o for month m shall be calculated as follows:

$$
RMR\ PayTotal\ A_{om} = \sum_{u} RMRPayA_{uom} + OPA_{om} + IAA_{om} + IDA_{om}
$$

(b) *Agreement B*

The Reliability Must-Run Payment under Agreement B for each month for each Owner shall be the total of the payments for that month for each Reliability Must-Run Unit owned by the Owner to which the Conditions of Must-Run Agreement B apply calculated in accordance with those Conditions. The Agreement B payment for Reliability Must-Run Owner o for Reliability Must-Run Unit u for month m shall be calculated as follows:

$$
\begin{aligned}
RMR\ Pay\ B_{uom} = \sum_{m} & [AP_{uot} + (EM_{uot} * ER_{uot}) + (E_{uot} * HVO\&M_{uot}) + (SCAC_{uot})] \\
& + HOF_{uom} + SUFC_{uom} + SUPC_{uom} + OSUC_{uom} + \\
& \sum_{m} [ASPDP_{uot} + VS_{uot}] \\
& - 0.9 * \sum_{m} [EMT_{uot} * PXM_t] - \sum_{m} [EA_{uot} * SCP_{uot}] \\
& - \sum_{m} [SCASCP_{uot}] - \sum_{m} [SCASEP_{uot}] - \sum_{m} [ER_{uot} * P_{xuot}]
\end{aligned}
$$

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$$RMR\ Pay\ B_{uom} = \sum_{m} \left[AP_{uot} + (EM_{uot} * ER_{uot}) + (E_{uot} * HVO\&M_{uot}) + (SCAC_{uot})\right]$$

$$+ HOF_{uom} + SUFC_{uom} + SUPC_{uom} + OSUC_{uom} +$$

$$\sum_{m} \left[ASPDP_{uot} + VS_{uot}\right]$$

$$- 0.9 * \sum_{m} \left[EMT_{uot} * PXM_{t}\right] - \sum_{m} \left[EA_{uot} * SCP_{uot}\right]$$

$$- \sum_{m} [SCASCP_{uot}] - \sum_{m} [SCASEP_{uot}] - \sum_{m} [ER_{uot} * P_{xuot}]$$

$$+ \sum_{m} [(ER_{uot} - E_{uot}) * P_{xuot}]$$

The total payment to each Owner for Reliability Must-Run services under Agreement B for a given month shall be calculated by summing all the payments for the month for the Reliability Must-Run Units owned by the Owner to which Agreement B applies. The payment for Owner o for month m shall be calculated as follows:

$$RMR\ PayTotal\ B_{om} = \sum_{u} RMRPayB_{uom} + OPB_{om} + IAB_{om} + IDB_{om}$$

(c) *Agreement C*

The Reliability Must-Run Payment under Agreement C for each month for each Owner shall be the total of the payments for that month for each Reliability Must-Run Unit owned by the Owner to which the Conditions of Must-Run Agreement C apply calculated in accordance with those Conditions. The Agreement C payment for Reliability Must-Run Owner o for Reliability Must-Run Unit u for month m shall be calculated as follows:

$$RMR\ PayC_{uom} = \sum_{m} \left[AP_{uot} + (EM_{uot} * ER_{uot}) + (E_{uot} * HVO\&M_{uot}) + (SCAC_{uot})\right]$$

$$+ HOF_{uom} + SUFC_{uom} + SUPC_{uom} + OSUC_{uom}$$

$$+ \sum_{m} [VS_{uot}] - \sum_{m} [EA_{uot} * SCP_{uot}]$$

$$- \sum_{m} [SCASCP_{uot}] - \sum_{m} [SCASEP_{uot}] - \sum_{m} [ER_{uot} * P_{xuot}]$$

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$$
\begin{aligned}
RMR\ Pay\,C_{uom} = & \sum_{m} \left[AP_{uot} + (EM_{uot} * ER_{uot}) + (E_{uot} * HVO\&M_{uot}) + (SCAC_{uot})\right] \\
& + HOF_{uom} + SUFC_{uom} + SUPC_{uom} + OSUC_{uom} \\
& + \sum_{m} \left[\, VS_{uot} \right] - \sum_{m} \left[EA_{uot} * SCP_{uot}\right] \\
& - \sum_{m} \left[SCASCP_{uot}\right] - \sum_{m} \left[SCASEP_{uot}\right] - \sum_{m} \left[ER_{uot} * P_{xuot}\right] \\
& + \sum_{m} \left[(ER_{uot} - E_{uot}) * P_{xuot}\right]
\end{aligned}
$$

The total payment to each Owner for Reliability Must-Run services under Agreement C for a given month shall be calculated by summing all the payments for the month for the Reliability Must-Run Units owned by the Owner to which Agreement C applies. The payment for Owner o for month m shall be calculated as follows:

$$
RMR\ Pay\ Total\ C_{om} = \sum_{u} RMRPayC_{uom} + OPC_{om} + IAC_{om} + IDC_{om}
$$

H 3 Meaning of terms of formulae

H 3.3 E_{uot} (MWh)

The Energy Delivered by Reliability Must-Run Unit u owned by Reliability Must-Run Owner o in Settlement Period t pursuant to a Dispatch Notice or an ISO's Request under the Conditions of Must-Run Agreement applicable to Reliability Must-Run Unit u. Energy Delivered can never exceed Energy requested by the ISO in Dispatch Notices or ISO’s Requests.

H 3.16.1 EA_{uot} (MWh)

The Energy requested to be Delivered by Reliability Must-Run Unit u owned by Reliability Must-Run Owner o in Settlement Period t ~~pursuant to~~ in a Dispatch Notice or an ISO’s Request issued in the Day-Ahead or the Hour-Ahead under the Conditions of Must-Run Agreement applicable to Reliability Must-Run Unit u.

H 3.19.1 ER_{uot} (MWh)

The Energy requested to be Delivered by Reliability Must-Run Unit u owned by Reliability Must-Run Owner o in Settlement Period t ~~pursuant to~~ in a Dispatch Notice or an ISO’s Request issued in Real Time under the Conditions of Must-Run Agreement applicable to Reliability Must-Run Unit u.

H 4 Data Input/Output

Term	Units	Variable Name	Input or Output	Detail Required
ER_{uot}	MWh	Energy Requested in Real Time	Input	By Unit By Settlement Period
P_{xuot}	$/MWh	Zonal Hourly Ex Post Price for Uninstructed Imbalance Energy	Input	By Unit By Settlement Period
$RMRPayTotalA_{om}$	$	Total RMR Payment under A	Output	
OPA_{om}	$	Other A Payment	Input	
IAA	$	Interest on adjustments	Input	
IDA	$	Interest on unpaid and disputed amounts	Input	

Scheduling Protocol Amendments

SP 3.2.6.1 Actions by SCs and the ISO

(i) the ISO will notify the SCs of any Reliability Must-Run Units which have not been included in Preferred Day-Ahead Schedules but which the ISO requires to run in the Trading Day, except in those instances where a Reliability Must-Run Unit requires more than one days' notice, in which case the ISO may notify the applicable SC more than one day in advance of the Trading Day; and

H. Changes to Settlement Calculations

The ISO proposes clarifications to Appendices C and D of the Settlement and Billing Protocol related to the calculations for buy back/sell back of Ancillary Services, and the removal of a typographical error in the formulae for calculating payments and charges for Imbalance Energy.

SETTLEMENT AND BILLING PROTOCOL APPENDIX C AMENDMENTS

C 2.1.2 Hour-Ahead Market

(a) *Regulation*. When the ISO purchases ~~regulation~~Regulation capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units that provide this capacity will receive payment for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit which provides Regulation capacity over the Trading Interval will be the total quantity of Regulation capacity provided times the zonal Market Clearing Price for that Trading Interval in that Zone. The required Regulation capacity is defined in the Ancillary Services Requirements Protocol. This payment for Scheduling Coordinator j for providing Regulation capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$\cancel{AGCPayHA_{ijxt} = AGCQHA_{ijxt} * PAGCHA_{xt}}$$

$$AGCPayHA_{ijxt} = AGCQIHA_{ijxt} * PAGCHA_{xt}$$

When a Scheduling Coordinator buys back, in the Hour-Ahead Market, Regulation capacity which it sold to the ISO in the Day- Ahead Market, the payment which the ISO receives will be the total quantity of Regulation capacity bought back times the zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Regulation capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCReceiveHA_{ijxt} = AGCQDHA_{ijxt} * PAGCHA_{xt}$$

The total Regulation payment for the Trading Interval of the Hour-Ahead Market to each Scheduling Coordinator for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$AGCPayTotdHA_{jxt} = \sum_i AGCPayHA_{ijxt} - \sum_i AGCReceiveHA_{ijxt}$$

(b) *Spinning Reserve*. When the ISO purchases Spinning Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units that provide this capacity will receive payments for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit which provides Spinning Reserve capacity over the Trading Interval will be the total quantity of Spinning Reserve capacity provided times the zonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

~~$SpinPayHA_{ijxt} = SpinQHA_{ijxt} * PSpinHA_{xt}$~~

$SpinPayHA_{ijxt} = SpinQIHA_{ijxt} * PSpinHA_{xt}$

When a Scheduling Coordinator buys back in the Hour-Ahead Market Spinning Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Spinning Reserve capacity bought back times the zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$SpinReceiveHA_{ijxt} = SpinQDHA_{ijxt} * PSpinHA_{xt}$

The total Spinning Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Spinning Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$SpinPayTotalHA_{jxt} = \sum_i SpinPayHA_{ijxt} - \sum_i SpinReceiveHA_{ijxt}$$

(c) *Non-Spinning Reserve.* When the ISO purchases Non-Spinning Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units and Loads that provide this capacity will receive payment for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit or Load which provides Non-Spinning Reserve capacity over the Trading Interval will be the total quantity of Non-Spinning Reserve capacity provided times the zonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$\cancel{NonSpinPayHA_{ijxt} = NonSpinQHA_{ijxt} * PNonSpinHA_{xt}}$$

$$NonSpinPayHA_{ijxt} = NonSpinQIHA_{ijxt} * PNonSpinHA_{xt}$$

When a Scheduling Coordinator buys back in the Hour-Ahead Market Non-Spinning Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Non-Spinning Reserve capacity bought back times the zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$NonSpinReceiveHA_{ijxt} = SpinQDHA_{ijxt} * PNonSpinHA_{xt}$

The total Non-Spinning Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Non-Spinning Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$NonSpinPayTotalHA_{jxt} = \sum_i NonSpinPayHA_{ijxt} - \sum_i NonSpinReceiveHA_{ijxt}$$

(d) *Replacement Reserve.* When the ISO purchases Replacement Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units and Loads that provide this capacity will receive payments for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit or Load which provides Replacement Reserve capacity over the Trading Interval will be the total quantity of Replacement Reserve capacity provided times the zonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

~~$ReplPayHAijxt = ReplQHAijxt * PReplHAxt$~~

$ReplPayHAijxt = ReplQIHAijxt * PReplHAxt$

When a Scheduling Coordinator buys back in the Hour-Ahead Market Replacement Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Replacement Reserve capacity bought back times the zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$ReplReceiveHA_{ijxt} = ReplQDHA_{ijxt} * PReplHA_{xt}$$

The total Replacement Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Replacement Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$ReplPayTotalHA_{jxt} = \sum_i ReplPayHA_{ijxt} - \sum_i ReplReceiveHA_{ijxt}$$

C 2.2.3 Replacement Reserve

Only undispatched Replacement Reserve capacity charges are covered within the Ancillary Services calculations. Dispatched Replacement Reserve capacity charges are covered within the Imbalance Energy calculations in Appendix D. This enables the ISO to allocate the cost of Dispatched Replacement Reserve capacity to those Scheduling Coordinators who contributed to the Imbalance Energy requiring such Dispatch.

If there is Congestion in the Day-Ahead Market the ISO will allocate the Replacement Reserve capacity Charges (both Dispatched and Un-Dispatched) on a Zonal basis. If there is no Congestion in the Day-Ahead Market the ISO will allocate the Replacement Reserve capacity

Charges on a ISO Control Area-wide basis (irrespective of whether there is Congestion in the Hour-Ahead Markets or not) and references in C 2.2.3 of this Appendix C to Settlement and Billing Protocol to "Zone(s)", "Zonal" and the use of subscript "x" shall be read as referring to "ISO Control Area".

The ISO will charge the zonal net cost of providing undispatched Replacement Reserve capacity that is not self provided by Scheduling Coordinators, in the Day-Ahead and Hour-Ahead Markets, through the application of a charge to each Scheduling Coordinator for each Trading Interval. This charge will be computed by multiplying the undispatched Replacement Reserve capacity user rate for the Trading Interval by the Scheduling Coordinators Replacement Reserve obligation, for which it has not self provided, for the same Trading Interval.

The zonal undispatched Replacement Reserve capacity user rate is calculated by dividing the net cost to ISO of purchasing undispatched Replacement Reserve capacity within the Zone, for the Trading Interval, by the total ISO Replacement Reserve obligation for the Trading Interval within the Zone. The total net cost to ISO to purchase undispatched Replacement Reserve capacity is equal to the total cost to ISO to purchase Replacement Reserve capacity less any amounts payable to the ISO by Scheduling Coordinators for Replacement Reserve bought back from the ISO in the Hour-Ahead Market on behalf of resources located in the Zone less the cost for Replacement Reserve capacity which was Dispatched. The undispatched Replacement Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$UnDispReplRate_{xt} = \frac{(\sum_{j} ReplPayTotal_{jxt}) - RRC}{ReplObligTotal_{xt}}$$

The zonal cost of Replacement Reserve capacity which is dispatched in the Real Time Market in a Trading Interval is calculated by multiplying the quantity of Replacement Reserve capacity Dispatched in the Trading Interval in the Zone by the average price paid for Replacement Reserve capacity scheduled in the Day-Ahead Market and the Hour-Ahead Market for the same Zone and Trading Interval. The cost of Replacement Reserve capacity dispatched in the Real Time Market in Zone x for Trading Interval t is calculated as follows:

$$RRC = PavgRepl_{xt} * ReplQDisp_{xt}$$

The average price paid for Replacement Reserve capacity in the Day-Ahead Market in Zone x in Trading Interval t is calculated as follows:

$$\cancel{PavgRepl_{xt}} = \frac{\sum_j ReplPayTotalDA_{jxt} + \sum_j ReplPayTotalHA_{jxt}}{\sum_{ij} ReplQDA_{ijxt} + \sum_{ij} ReplQHA_{ijxt}}$$

$$PavgRepl_{xt} = \frac{\sum_j ReplPayTotalDA_{jxt} + \sum_j ReplPayTotalHA_{jxt}}{\sum_{ij} ReplQDA_{ijxt} + \sum_{ij} ReplQIHA_{ijxt} - \sum_{ij} ReplQDHA_{ijxt}}$$

The undispatched Replacement Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead and Hour-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$UnDispReplChg_{jxt} = (ReplOblig_{jxt} * UnDispReplRate_{xt}) - (ReplSellBack_{jxt} * UnDispReplRate\cancel{HA}_{xt})$$

C 3 Meaning of terms of formulae

C 3.3 PAGCDA$_{xt}$ - \$/MW~~w~~

The Market Clearing Price for ~~Non-FERC jurisdictional~~ units exempt from FERC Ancillary Service rate caps or the bid price for ~~FERC jurisdictional~~ those Units subject to the cap for Regulation capacity in the Day-Ahead Market for Trading Interval t in Zone x.

C 3.6 AGCQIHA$_{ijxt}$ – MW~~w~~

The total quantity of incremental (additional to Day-Ahead) Regulation capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.7 AGCQDHA$_{ijxt}$ – MW

The total quantity of decremental (less than Day-Ahead) Regulation capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.7.1 PAGCHA$_{xt}$ - \$/MW

The Market Clearing Price for ~~Non-FERC jurisdictional~~ units exempt from FERC Ancillary Service rate caps or the bid price for ~~FERC~~

~~jurisdictional~~ those units subject to the cap for incremental (additional to Day-Ahead) Regulation capacity in the Hour-Ahead Market for Trading Interval t in Zone x. On buyback condition, MCP applies.

C 3.23 PSpinDA$_{xt}$ -$/MW

The Day-Ahead Market Clearing Price for ~~Non-FERC jurisdictional~~ units exempt from FERC Ancillary Service rate caps or the bid price for ~~FERC jurisdictional~~ those units subject to the cap for Spinning Reserve capacity in Zone x for Trading Interval t.

C 3.26 SpinQIHA$_{ijxt}$ – MW

The total quantity of incremental (additional to Day-Ahead) Spinning Reserve capacity provided in the Hour-Ahead Market by resource i represented by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.27 SpinQDHA$_{ijxt}$ – MW

The total quantity of decremental (less than Day-Ahead) Spinning Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.27.1 PSpinHA$_{xt}$ -$/MW

The Hour-Ahead Market Clearing Price for ~~Non-FERC jurisdictional~~ units exempt from FERC Ancillary Service rate caps or the bid price for ~~FERC jurisdictional~~ those units subject to the cap for incremental (additional to Day-Ahead) Spinning Reserve capacity in Zone x for Trading Interval t. On Buyback condition, MCP applies charge for HA.

C 3.39 PNonSpinDA$_{xt}$ - $/MW

The Day-Ahead Market Clearing Price for ~~Non-FERC jurisdictional~~ units exempt from FERC Ancillary Service rate caps or the bid price for ~~FERC jurisdictional~~ those units subject to the cap for Non-Spinning Reserve capacity for Trading Interval t in Zone x.

C 3.42 NonSpinQIHA$_{ijxt}$ – MW

The total quantity of incremental (additional to Day-Ahead) Non-Spinning Reserve capacity provided from resource i in the Hour-

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Ahead Market by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.43 NonSpinQDHA$_{ijxt}$ – MW

The total quantity of decremental (less than Day-Ahead) Non-Spinning Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.43.1 PNonSpinHA$_{xt}$ - $/MW

The Hour-Ahead zonal Market Clearing Price for ~~Non-FERC jurisdictional units~~ units exempt from FERC Ancillary Service rate caps or the bid price ~~for FERC jurisdictional units~~ for those units subject to the cap for incremental (additional to Day-Ahead) Non-Spinning Reserve capacity for Trading Interval t in Zone x. On Buyback condition, MCP applies.

C 3.55 PReplDA$_{xt}$ -$/MW

The Day-Ahead Market Clearing Price for ~~Non-FERC jurisdictional~~ units exempt from FERC Ancillary Service rate caps or the bid price for ~~FERC jurisdictional~~ those units not subject to the cap for Replacement Reserve capacity in Zone x for Trading Interval t.

C 3.58 ReplQIHA$_{ijxt}$ – MW

The total quantity of incremental (additional to Day-Ahead) Replacement Reserve capacity provided in the Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.59 ReplQDHA$_{ijxt}$ – MW

The total quantity of decremental (less than Day-Ahead) Replacement Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.59.1 PReplHA$_{xt}$ -$/MW

The Hour-Ahead Market Clearing Price for Non-FERC jurisdictional units or the bid price for FERC jurisdictional units for incremental (additional to Day-Ahead) Replacement Reserve capacity in Zone x for Trading Interval t. On Buyback condition, MCP applies.

C 3.61 UnDispReplRate$_{xt}$ - $/MW

The Day-Ahead and Hour-Ahead undispatched Replacement Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t. ~~Where UnDispReplRate WA$_{xt}$ is applied to ReplSellBack $_{jxt}$ it shall be set at zero if there is no market for the sale by the ISO of the Replacement Reserve capacity concerned to other Scheduling Coordinators.~~

I. Changes to Contingency Measures

Over the period leading to the ISO Operations Date, the ISO has been developing a number of operating procedures and contingency plans to meet possible eventualities. One of these relates to the procedures which the ISO will follow if it does not receive any, or a sufficient amount of, Preferred Schedules in either the Day-Ahead or Hour-Ahead Markets. Whatever the reason for such a deficiency, the ISO needs to ensure that Market Participants are aware of the actions the ISO will take.

The ISO presently has the ability, under SP 3 of the Scheduling Protocol, to implement temporary variations of timing requirements in the Day-Ahead and Hour-Ahead Markets, either for reliability purposes or due to error or delay. The ISO's operating procedures provide that, pursuant to SP 3, the ISO will hold open the market until it has received sufficient Preferred Schedules and will notify Scheduling Coordinators on the WEnet.

It is possible, however, that the delay in the market could reach such a state that the Day-Ahead Market operations could not be run. Again, pursuant to SP 3, the ISO has the ability to omit some of the steps in the timing requirements of the Markets in order to mitigate the problem.

Even this step may, however, not be sufficient in extreme circumstances and, in such cases, the ISO proposes that it should be given the authority to abort the Day-Ahead Market and require all Schedules to be submitted in the Hour-Ahead Market. For similar reasons, there may be inadequate time to operate the Hour-Ahead Market and, again, in that eventuality, the ISO proposes that it first deem final Day-Ahead Schedules to be Preferred Hour-Ahead Schedules for those hours, as described in SP 3.3. If that fails, the ISO needs the ability to abort the Hour-Ahead Schedule and operate in real time.

A further scenario is the possibility that the ISO may be unable to run Congestion Management, because of, for example, a scheduling or software problem. Again, the ISO proposes to resolve this problem pursuant to SP 3, both as currently filed and by an amendment of SP 3.

Currently, SP 3 provides that if the ISO is unable to run Congestion Management, the ISO has the ability to implement temporary variations of timing requirements of the Day-Ahead and Hour-Ahead Markets, either for reliability purposes or due to error or delay. If, despite the variation of any timing requirement or omission of any step, the ISO still is unable to run Congestion Management, then, pursuant to this amendment, the ISO will have the ability to abort the Day-Ahead Market and instead run Congestion Management on the Hour-Ahead Market. For similar reasons, there may be inadequate time to operate the Hour-Ahead Market and, if so, the amendment will provide the ISO with the authority to abort Congestion Management in the Hour-Ahead Market and operate in real time.

SCHEDULING PROTOCOL AMENDMENTS

SP 3 Time Lines

(b) If, despite the variation of any time requirement or the omission of any step, the ISO either fails to receive sufficient Schedules to operate the Day-Ahead Market or is unable to perform Congestion Management in the Day-Ahead Market, the ISO may abort the Day-Ahead Market and require all Schedules to be submitted, and Congestion Management to be performed, in the Hour-Ahead Market.

(c) If, despite the variation of any time requirement or omission of any step, the ISO either fails to receive sufficient Schedules to operate the Hour-Ahead Market or is unable to perform Congestion Management in the Hour-Ahead Market, the ISO may abort the Hour-Ahead Market and function in real time.

(~~b~~d) The incorporation of the scheduling of the use of rights under Existing Contracts into the ISO's Day-Ahead, Hour-Ahead and real time processes is additionally described in SP 7 and in the SBP.

J. Changes Respecting Neutrality Adjustments

The Settlement and Billing Protocol contains provisions for the ISO to levy additional charges and payments that arise when it is not possible to balance the ISO Clearing Account by means of a "neutrality adjustment." A charge arising from cash imbalances due to "rounding" was the first charge identified as a situation to be handled by way of the neutrality adjustment.

The changes in the Imbalance Energy pricing calculations, discussed in part A, create additional cash imbalances that will be handled through neutrality adjustments. In addition, further imbalances were identified during the coupled test that must be handled through the neutrality adjustment.

In particular, it has become apparent that there are a variety of "other causes" for cash imbalances, beyond the "rounding" issue, that will require the use of the neutrality adjustment. Such "other causes" include the following.

- **Control Area inadvertent Energy interchanges**: Scheduling Coordinator import and export schedules at intertie points are "deemed" to equal the actual meter reads. This is because there are multiple schedules at each tie, and it is not possible to disaggregate hourly reads and assign them to individual schedules. This "deeming" results in zero import/export imbalances while there may be aggregate imbalances at the interties due to inadvertent flows. Unaccounted-for-Energy (UFE) is increased (or decreased) by these imbalances every hour and is charged to Scheduling Coordinators without any offsetting counter-charge (or credit).

- **Real time Inter-Zonal Congestion**: Inter-Zonal Congestion in real time will require resources to be dispatched in the importing and exporting Zones to mitigate the overload. To the extent that payments and charges in each separate Zone are not identical, there will be cash imbalances.

- **Differences in calculation of Transmission Losses on imports in formulae for Imbalance Energy and UFE**: Losses associated with import schedules are calculated in the import deviations formulae based on Scheduling Coordinators' schedules. Losses associated with import "actuals" are calculated as part of the UFE Settlement and are based on intertie metered values. Since the intertie metered values net import and export schedules, there may be smaller amounts of losses computed in UFE than in the Imbalance Energy calculations. This also creates cash imbalances.

- **Imbalance in forward market schedules**: To the extent the sum of scheduled Generation, imports, Loads, exports and Inter-Scheduling Coordinator Trades is not balanced (yet within allowable ISO mismatch tolerance – which is set by the ISO at amounts between 1 MW and 20 MW as discussed in part K), the ISO may find UFE which is not offset by any Imbalance Energy charge or payment.

- **Differences in settlements due to price calculations for instructed and uninstructed deviations:** Payments for instructed Imbalance Energy in the new Real Time Market pricing methodology will be paid based on the Energy "instructed." Any differences between this instruction and the meter reads from the Generation Units will be charged (or paid) at the Imbalance Energy Price for uninstructed deviations. The differences in these prices will cause revenue mismatches whenever units fail to meet ISO instructions.

Having identified, as a result of the coupled testing, the existence of these various imbalances, it was clear to the ISO that the language relating to neutrality adjustments in the Settlements and Billing Protocol should be reviewed to ensure that it adequately reflected the operation of the software. As a result of that review, the ISO is making further minor changes to the Settlement and Billing Protocol, to align it with the way the software operates. In addition, the ISO Tariff contains, at present, no provisions on neutrality adjustments. An additional section is, therefore, being inserted in the ISO Tariff, similar to the Settlements and Billing Protocol's provisions, to address this issue.

Finally, the ISO notes that several Scheduling Coordinators expressed concern about the degree of discretion afforded to the ISO with respect to Neutrality Adjustments. This discretion has been in the ISO Tariff (specifically, the Settlements and Billing Protocol) but may not have been fully comprehended until specific examples were called to the attention of Market Participants by the ISO's circulation of a draft of this Amendment No. 6. To give Market Participants assurance that the Neutrality Adjustment is not being abused by the ISO, and in response to comments received from Scheduling Coordinators the ISO will make publicly available, on a periodic basis, the amounts flowing through the Neutrality Adjustment, by category. In addition, the ISO will continue to pursue software changes to classify and properly allocate the items for which the Neutrality Adjustment is used – seeking stakeholder input on which items are of significant magnitude to warrant additional investments of time and/or capital to apportion cash imbalances.

SETTLEMENT AND BILLING PROTOCOL AMENDMENT

SABP 3.1.1 Additional Charges and Payments

The ISO shall be authorized to levy additional charges or payments as special adjustments in regard to:

(a) amounts required to round up any invoice amount expressed in dollars and cents to the nearest whole dollar amount in order to clear the ISO Clearing Account. These charges will be allocated amongst Scheduling Coordinators over an interval determined by the ISO and pro rata based on metered Demand (including exports) during that interval~~the ISO Creditors and ISO Debtors on that Trading Day pro rata to their net payments aor charges~~;

~~(a)~~(b) amounts in regard to penalties which may be levied by the ISO in accordance with the ISO Tariff. These charges will be levied on the Market Participants liable for payment of the penalty; and

(c) amounts required to reach an accounting trial balance of zero in the course of the Settlement process in the event that the charges calculated as due from ISO Debtors are lower than payments calculated as due to the ISO Creditors for the same Trading Day. These charges will be allocated amongst the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (~~plus~~ including exports) in MWh of Energy for that Trading Day. In the event that the charges due from ISO Debtors are higher than the payments due to ISO Creditors, the ISO shall allocate a payment to the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (~~plus~~ including exports) in MWh of Energy for that Trading Day.

ISO TARIFF AMENDMENTS

11.2.9 Neutrality Adjustments

The ISO shall be authorized to levy additional charges or payments as special adjustments in regard to:

(a) amounts required to round up any invoice amount expressed in dollars and cents to the nearest whole dollar amount in order to clear the ISO Clearing Account. These charges will be allocated amongst Scheduling Coordinators over an interval determined by the ISO and pro rata based on metered Demand (including exports) during that interval;

(b) amounts in regard to penalties which may be levied by the ISO in accordance with the ISO Tariff. These charges will be levied on the Market Participants liable for payment of the penalty; and

(c) amounts required to reach an accounting trial balance of zero in the course of the Settlement process in the event that the charges calculated as due from ISO Debtors are lower than payments calculated as due to the ISO Creditors for the same Trading Day. These charges will be allocated amongst the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (including exports) in MWh of Energy for that Trading Day. In the event that the charges due from ISO Debtors are higher than the payments due to ISO Creditors, the ISO shall allocate a payment to the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (including exports) in MWh of Energy for that Trading Day.

K. Changes to the ISO Schedule Validation Tolerance

Amendment No. 5 introduced a temporary simplification to facilitate ISO validation of Scheduling Coordinators' Balanced Schedules by increasing the 1 MW "tolerance," within which a Schedule would be deemed to be balanced, to 20 MW. Amendment No. 5 further proposed that this simplification would terminate upon ISO notice. In discussions with Scheduling Coordinators, principally the PX, the ISO has determined that a 20 MW tolerance is likely not necessary and may result in unnecessary imbalances in settlements. On the other hand, Amendment No. 5 contemplated either 20 MW or 1 MW. A sliding scale for adjusting the tolerance appears more appropriate. Therefore, the ISO is filing an amendment to the earlier-filed Section 22, to allow the ISO to reduce the 20 MW "tolerance" band, after giving Scheduling Coordinators one day's notice, posted on the ISO's Home Page. Initially, the tolerance will be set at 2MW.

ISO TARIFF AMENDMENT

22.1 Temporary Simplification of Schedule Validation Tolerances

Notwithstanding any other provision in the ISO Tariff, including the ISO Protocols, a Schedule shall be treated as a Balanced Schedule when aggregate Generation, adjusted for Transmission Losses, is within 20 MW of aggregate Demand, or such lower amount, greater than 1 MW, as may be established from time to time by the ISO. The ISO may establish the Schedule validation tolerance level at any time, between a range from 1 MW to 20 MW, by giving seven days' notice published on the ISO's "Home Page," at http://www.caiso.com or such other internet address as the ISO may publish from time to time.

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L. Temporary Liability and Exclusion Provisions

The ISO Tariff is, perhaps, unique in its detail and complexity. It is certainly far more detailed than *pro forma* tariffs filed by utilities under Order No. 888. The inability of the ISO to date to complete a comprehensive review and justification for excluding all or any part of the Protocols as part of the filed ISO Tariff creates additional detail and complexity. Thus, where many, if not most, utilities have typically been obligated to honor the express terms of their tariff and suffer liability for even negligent failure to do so, the ISO respectfully submits that the unique detail and complexity of the ISO Tariff presents an almost insurmountable standard of conduct and the potential for endless and possibly intractable disputes. The problem is intensified by the nature of the ISO market design – with 8,760 Settlement Periods annually and up to 42 separate charge types – for multiple Scheduling Coordinators whose individual statements are, by definition, interdependent on the charges made to every other Scheduling Coordinator.

During the coupled market demonstration testing, it became apparent that situations will occasionally arise in which the ISO operations and settlements staff make inadvertent errors in performing their duties under the ISO Tariff, including the ISO Protocols. In most instances, these errors will not be of a significant nature and remedial measures will be relatively straightforward. In other instances, the errors may result in impacts on Scheduling Coordinators that require more extensive corrective actions. In at least some cases, the egg simply cannot be unscrambled.

Obviously, as the ISO operations and settlements staff gain more familiarity with the system, the frequency of such errors will be reduced. In addition, over the next few months, the ISO will continue to develop administrative procedures designed to prevent the occurrence of such errors. Further, the ISO is developing numerous situation-specific correcting and remedial measures to be taken, if such events occur in the future. On the other hand, the ISO could be crippled in its ability to operate if faced with potential liability for what is undeniable – that humans will, occasionally, be human. Although not all human error rises to the level of negligence, the exhaustive detail of the ISO Protocols and the interrelated charges of all Scheduling Coordinators creates a very real risk of chaos if certain, albeit negligent, mistakes were to happen and the effects could not be resolved without an extremely burdensome and costly process.

A summary of some, but not all, of the potential human errors identified to date is included for the Commission's information as **Attachment C**.

ISO management, when considering the liability issue during the coupled test, initially undertook to review the ISO Tariff to identify all potential areas where the ISO Tariff should be amended to clarify the standard against which the

ISO would be expected to act. It soon became clear, however, that this task could not be accomplished prior to start-up. Moreover, it is a task more appropriately handled in a stakeholder process that addresses the larger issue of which Protocols may be excluded from the ISO Tariff as true operating procedures, rather than contractual obligations, and which ones should be added to the main body of the ISO Tariff. This task has a high post-start-up priority for ISO management.

The ISO is mindful of the ruling of the Commission, in its October 30 Order, that the ISO's liability should extend to situations where damages have resulted from ***all*** types of negligence on the part of the ISO.[1] The ISO's December 1, 1997 request for rehearing of that aspect of the October 30 Order, in which the ISO first proposed a "gross negligence" standard, is still pending.

However, until the rehearing is decided and the ISO can conclude its Protocol review, the ISO respectfully submits that an interim "gross negligence" standard is appropriate. This is particularly so given the need for ISO operators and settlement staff to gain experience with the various complex rules and procedures (and substantial manual work-arounds necessary to allow on-time operations). This interim amendment is, therefore, submitted by the ISO without prejudice to the position that any party, including the ISO, has taken or may take with respect to the liability issues raised in the October 30 Order, the ISO's rehearing request or any subsequent appellate or other proceedings arising therefrom.

In view of the above, the ISO is filing the special, temporary, liability provisions set out in proposed new Section 25 of the ISO Tariff. Essentially, Section 25 provides that, during a prescribed interim period, ***ending on December 31, 1998,*** the ISO's liability for damages to any Market Participant, arising from the ISO's performance or non-performance of its obligations under the ISO Tariff, shall be limited to situations in which the damages result from either intentional wrongdoing or gross negligence on the part of the ISO.

25. TEMPORARY LIABILITY AND EXCLUSION PROVISIONS

25.1 Application and Termination

The temporary liability and exclusion provisions set out in Sections 25.2 and 25.3 shall continue in effect up to and including December 31, 1998.

[1] See 81 FERC at 61,520.

25.2 Temporary Liability Provision

Notwithstanding any other provision in the ISO Tariff, the ISO shall not be liable in damages to any Market Participant, other than as provided for in Section 13.3.14, for any losses, damages, claims, liability, costs or expenses (including legal expenses) arising from the performance or non-performance of its obligations under this ISO Tariff, except to the extent that the ISO's breach of the provisions of the ISO Tariff results directly from gross negligence or willful misconduct on the part of the ISO.

25.3 Temporary Exclusion of Certain Types of Loss.

The ISO shall not be liable to any Market Participant under any circumstances for any consequential or indirect financial loss, including but not limited to loss of profit, loss of earnings or revenue, loss of use, loss of contract or loss of goodwill resulting from physical damage to property for which the ISO may be liable under Section 25.2.

M. Temporary Changes to Ancillary Services Penalties

As noted above, a significant concern identified in testing to date is the apparently "thin" Ancillary Services market. Accordingly, the ISO has continued to search for provisions in the ISO Tariff which may have the effect of discouraging Scheduling Coordinators from submitting Ancillary Services bids. During the coupled test, the ISO identified one such provision that it is now modifying.

The ISO Tariff provides for penalizing Scheduling Coordinators for non-performing with respect to Ancillary Services (ISO Tariff Section 2.5.26). Prior to the coupled test, there were few, if any, objections to such penalties. However, results of the coupled test highlighted for Scheduling Coordinators the risk of such penalties. In reviewing the concerns with Scheduling Coordinators, the ISO determined that the risk is exacerbated by (1) the increased emphasis on submitting adequate Adjustment Bids and (2) the process in which the ISO's software sequentially evaluates Congestion Management and Ancillary Services.

The ISO's Congestion Management software (CONG) and Ancillary Services management processes run sequentially in the ISO's scheduling system. In the event of Congestion, some resources may be adjusted to the point at which their Revised Schedules conflict with their offered Ancillary Services. For example, a 100 MW Generator, with an initial Preferred Schedule of 75 MW, may also bid to supply 25 MW of Spinning Reserve. As a result of Congestion, the Generator may be adjusted to 80 MW. The ISO's Ancillary Services evaluation, as presently configured in the scheduling system, will not take into account the 5 MW adjustment, assuming that the whole of the 25 MW bid to supply Spinning Reserves is available. If this Generator is selected by the ISO to provide the full 25 MW of Spinning Reserve, and the ISO subsequently calls on the resource in real time to supply balancing Energy, the Scheduling Coordinator will not be in a position to respond fully and may be subject to penalties unless it can obtain substitute Energy for its Adjustment Bid so that the unit supporting Ancillary Services can be devoted to providing that service.

This is particularly troublesome for Scheduling Coordinators like the PX that are not able to submit Revised Preferred Day-Ahead Schedules or Hour-Ahead Schedules, until some months after the ISO Operations Date, and Scheduling Coordinators without access to multiple units.

The ISO therefore proposes changes to its Ancillary Services management software to properly account for Congestion Management adjustments to schedules. These software changes are currently under development and the ISO proposes to implement them as soon as they can be finished and satisfactorily tested. The ISO believes this software will be functional at some point after the ISO Operations Date.

For this reason, the ISO has set out, in new, temporary, Section 26, a provision waiving the cited penalties to avoid unnecessary impediments to Ancillary Services bids. The penalties will be reinstated when the software is functional, after giving Scheduling Coordinators seven days' notice that this has occurred.

26 TEMPORARY CHANGES TO ANCILLARY SERVICES PENALTIES

26.1 Application and Termination

The temporary change, respecting Ancillary Services penalties, set out in Section 26.2 shall continue in effect until such time as the Chief Executive Officer of the ISO issues a Notice of Full-Scale Operations, posted on the ISO Internet "Home Page", at http://www.caiso.com, or such other Internet address as the ISO may publish from time to time, specifying the date on which this Section 26 shall cease to apply, which date shall be not less than seven (7) days after the Notice of Full-Scale Operations is issued.

26.2 For so long as this Section 26.2 remains in effect, Scheduling Coordinators shall not be liable for the penalties specified in Section 2.5.26 of the ISO Tariff.

ATTACHMENT B

Notice Suitable for Publication in the Federal Register

Pacific Gas and Electric Company,)
San Diego Gas & Electric Company, and) **Docket Nos. EC96-19-___**
Southern California Edison Company) **ER96-1663-___**

NOTICE OF FILING

Take notice that on March 23, 1998, the California Independent System Operator Corporation (ISO) filed for Commission acceptance in this docket, pursuant to Section 205 of the Federal Power Act, an application to amend the ISO Operating Agreement and Tariff, including the ISO Protocols ("ISO Tariff") (Tariff Amendment No. 6). The ISO requests that the Tariff Amendment No. 6 be accepted for filing and be made effective as of the ISO Operations Date.

The ISO states that Amendment No. 6 addresses issues identified during the recent coupled market demonstration testing. The proposed changes consist of (A) temporary changes to the Real-Time Market for Imbalance Energy;
(B) temporary changes respecting physical constraints on Schedules; (C) changes to provisions respecting System Reliability; (D) changes in regard to Overgeneration Management; (E) changes to give Load and implicit priority in Congestion Management, (F) changes to the default Usage Charge; (G) changes to Reliability Must-Run Unit settlements; (H) changes to Settlement calculations; (I) changes to contingency measures; (J) changes respecting neutrality adjustments; (K) change to the ISO Schedule validation tolerance; (L) temporary liability and exclusion provisions; and (M) temporary changes to Ancillary Services penalties.

Any person desiring to be heard or to protest said filing should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with 18 C.F.R. §§ 385.212 and 385.207. All such petitions or protests should be filed on or before _________. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this application are on file with the Commission and available for public inspection.

ATTACHMENT C

EXAMINATION OF POTENTIAL ISO MANUAL ERRORS: DEFINITION, IMPACTS, PREVENTION, and CORRECTION

3/10/98

The new California market system depends heavily on the provision of accurate information – to Scheduling Coordinators, generators, dispatchers, etc. – to function properly.

Implementing many aspects of the new structure will require manual efforts by ISO employees, and there is the potential for human error. Such errors could result in some degree of inefficient functioning of the market and adverse financial impacts to market participants.

Even when the errors are detected and corrected, the market design requirement that the ISO be financially neutral imposes constraints on the potential remedies. For example, the ISO has no earnings that might be reduced or increased from such corrections, and deficits or surpluses cannot be carried into future periods.

It is inevitable that at least some of these errors will occur; several instances of this have already surfaced in market testing. Therefore, while none of these potential errors would themselves be significant enough to impede ISO startup, it is important to identify them and determine, in advance, possible preventive and/or corrective measures.

The potential human errors can be classified into two categories: those affecting operations and market functions, and those affecting only settlements and billing.

Errors affecting operations and market functions would be the most serious. These mistakes could cause the ISO to make incorrect operations or resource decisions and incur additional costs that must be recovered from market participants. They could also cause SCs to make incorrect decisions and incur additional costs, affecting the efficiency of the critical market features of the new system.

Potential errors that affect only billing and settlements would be considered less critical. While these errors may impact individual SCs significantly until corrections are made, they would generally affect only after-the-fact calculations that would be relatively easily corrected.

Preventive actions largely consist of either ISO employee educational efforts or, where the problem is persistent, manual checks by an additional employee to ensure that the procedures are done, and done correctly. In the longer term, the potential for many of these errors can be avoided through additional automation of the work tasks.

Corrective actions are also recommended if the errors occur despite preventive measures.

ITEMS AFFECTING OPERATIONS/MARKET FUNCTION

1. Insufficient A/S bids in the day-ahead market

Definition: There are not enough A/S resources bid into the day-ahead market to cover all loads scheduled in the day-ahead market. A somewhat complex manual workaround has been identified to ensure that the ISO's day-ahead A/S procurement is sufficient and does not affect A/S provision in the hour-ahead market. However, it is possible that ISO employees might either forget to make the adjustment or might make a mistake while doing so.

Impact:

- More A/S than needed will be procured to cover the day-ahead deficiency as needed (i.e., additional cost).
- The additional cost will be spread over all loads not self-providing, including those of SCs not scheduling in the hour-ahead market (e.g., PX).

Proposed preventive measures:

- The ISO employees responsible for this task will be educated with respect to its importance of the task and the need to ensure accuracy.
- The built-in automatic reminder on the computer screen will be programmed to remind both of these employees to carry out this task.
- If the error occurs more than twice more during market demonstration, an additional employee will be assigned the responsibility of checking to make sure that the work has been done and/or that the corrections are accurate.
- In the longer term, the software program will be modified to allow RMR A/S resources to be input into the day-ahead market program so that any deficiency remedied in that manner is not carried forward into the hour-ahead market.

Proposed correction: If, despite the above measures, the adjustment is not made, the following corrective actions will be taken:

- The duplicate A/S costs will be subtracted from the bills of customers not submitting adjustments in the hour-ahead market.

- The suppliers of the duplicate A/S must nevertheless be paid. To keep the ISO neutral, the costs will be added to the neutrality adjustment and spread over all reported loads.

2. Congestion iteration run with preferred (not revised preferred) schedules

Definition: When the congestion iteration is run, an operator might mistakenly run it using the preferred schedules, rather than the revised preferred schedules (revised by SCs to respond to congestion price signals). Since the iteration is typically run even when there are no schedule revisions, the operator might not detect the error. This error could also occur during fallback of the SA system, if the operator fails to clear the screens (possibly seen for three hours on March 4).

Impact:

- Market participants may incur costs that they would otherwise have avoided, such as:
  - congestion costs;
  - imbalance costs (e.g., generator that they were planning to buy from is not listed as scheduled by them)
- ISO must exercise "command and control" (e.g., pro rata curtailments) when the market could have handled the problem more efficiently.

Proposed preventive measures:

- The ISO employees responsible for this task will be educated with respect to its importance of the task and the need to ensure accuracy.
- A prompt to double-check that the correct schedules have been entered in the congestion run will be installed on the appropriate operator screen.

Proposed correction:

- If there is sufficient time, rerun the congestion iteration using the correct schedules.
- If there is insufficient time for a rerun, bill SCs using the congestion run as performed, except reduce congestion charges to correct level if they were too high (but take no action if they were too low). If invoices have already been issued, issue correction on next statement and debit TOs accordingly.

3. Incorrect path ratings used in CONG runs

Definition: Line capacity is lower or higher than that used, and this is known when CONG is run.

Impact: Similar to changes in real time that were not known in advance.

- Congestion may be shown when it does not exist, and schedules may be reduced unnecessarily.
- Congestion may not be shown (or may be more than shown) when it does exist, so schedule reductions may not be shown and SCs do not have advance opportunity to adjust.
- Congestion prices are incorrect (too high or too low), and SCs may overadjust schedules or not adjust enough (or at all).

Proposed preventive measures:

- The ISO employees responsible for this task will be educated with respect to its importance of the task and the need to ensure accuracy.

Proposed correction:

- If caught in time, rerun DA market.
- If DA market cannot be rerun, correct error in HA market, so SCs can adjust properly.
- If DA market cannot be rerun, bill SCs using schedules as run, except reduce congestion charges to correct level if they were too high (but take no action if they were too low). If invoices have already been issued, issue correction on next statement and debit TOs accordingly.

4. Manual data input errors for operational information

Definition: There are several places where data which impact operations are entered or manually adjusted. These include net tie setters (seen in the early morning errors for March 5.

Impact: The ISO could incur CPS2 or other violations of WSCC operating criteria.

Proposed preventive measures:

- Employees responsible for this function will be educated about the problem and cautioned to check their own work.
- If the problem occurs again during market demonstration, an employee other than that responsible for this function will assume duplicate responsibility for ensuring the adjustments are correct.
- In the longer term, the software program should be modified so that data

are passed automatically into the systems from the IOUs, without the need for manual input by ISO employees.

Proposed correction: None proposed.

5. Manual data input errors for scheduling information

Definition: There are several places where scheduling data are changed manually by ISO employees. These include adjustments to fix inter-SC trade mismatches and import/export schedule changes during real-time operations.

Impact: SCs could receive incorrect schedules and incur imbalance or congestion costs.

Proposed preventive measures:

- Employees responsible for this function will be educated about the problem and cautioned to check their own work.
- If the problem occurs again during market demonstration, an employee other than that responsible for this function will assume duplicate responsibility for ensuring the adjustments are correct.
- In the longer term, the software program should be modified so that these adjustments are made automatically, without the need for manual input by ISO employees.

Proposed correction:

- If error detected before preliminary statements invoices are issued, correct and rerun.
- If not, rerun and make corrections on final statements.
- If final statements have already been issued, take no further action.

6. Manual data input or transfer errors for dispatch information

Definition: When operators call on an RMR generating unit, or dispatch in real time another unit supplying supplemental energy, that action is entered into a logbook. It must later be transferred to billing/settlements personnel so that the unit owners can be paid.

Impact: If both these actions are not done, or mistakes are made when they are, then errors will be made in the invoices sent to SCs.

Proposed preventive measures:

- Employees responsible for this function will be educated about the problem and cautioned to check their own work.
- If the problem occurs again during market demonstration, an employee other than that responsible for this function will assume duplicate responsibility for ensuring the adjustments are correct.
- In the longer term, the software program should be modified so that these data can be input automatically, without the need for manual actions by ISO employees.

Proposed correction: Errors must be manually corrected and, if preliminary statements have already been issued, they must be corrected before final statements are issued.

7. Manual data transfer errors for dispatch information

Definition: Information on "inadvertents" must be transferred correctly from operations to billing/settlements personnel. Particularly within the tight time frame allowed for market demonstration, data might be transferred that is inaccurate or not updated for final numbers.

Impact: Invoices sent to SCs will be incorrect. Error will be reflected in the "neutrality adjustment."

Proposed preventive measures:

- Much of this problem will solve itself with the more relaxed timeframes for actual operation.
- Employees responsible for this function will be educated about the problem and cautioned to check their own work.
- If the problem occurs again during market demonstration, an employee other than that responsible for this function will assume responsibility for checking daily the data sent to settlements/billing.
- In the longer term, the software program should be modified so that these data can be transferred automatically, without the need for manual actions by ISO employees.

Proposed correction: Errors must be manually corrected and, if invoices have already been issued, they must be corrected on the next invoice.

ITEMS AFFECTING ONLY SETTLEMENTS/BILLING

1. Incorrect wheeling charges

Definition: Wheeling through and wheeling out calculations will have to be done manually for roughly the first three months after startup. Errors could be made in the price applied (particularly on paths where weighted average charges must be calculated), in the volumes that it is applied to, or in the calculation itself.

Impact:

- The SCs involved could be billed too much or too little.
- The IOUs involved could receive too much or too little revenue.

Proposed preventive measures: Ask IOUs to verify information during settlement review period.

Proposed correction: If, despite the above measures, the error is made, the following corrective actions will be taken:

- Because the relevant line items are entirely outside the billing system, the correction is relatively straightforward and simple.
- The SCs carrying out the affected transactions would receive a surcharge or credit.
- The relevant IOUs would receive a debit or credit.

2. **Wrong "net vs. gross" or other manual calculations for munis/governmental utilities**

Definition: Certain charges for munis/govt. utilities must be calculated manually. In addition, because these entities typically have multiple meters, several of which may have deliveries "deemed," there will often need to be manual verification that meter reads sum up to the correct totals.

Impact:

- For the charge calculations, the munis can be overcharged or undercharged.
- If the meter read totals are incorrect, the munis may be underallocated or overallocated their share of certain system costs, e.g., imbalance energy.

Proposed preventive measures: Ask customers to verify information during settlement review period.

Proposed correction: Recalculate bill and show correction on next statement. Reflect any A/S correction (or other correction that affects charges to other SCs) in a neutrality adjustment; since the total amounts involved, and thus the corrections, are likely to be small, do not manually adjust other SC bills.

3. Failure to detect very large SC data errors in reporting loads or generation

Definition:

- Major errors in scheduling/reporting generation data by SCs have occasionally been detected, e.g., reporting KWH data as MWH. Current systems will not detect reporting errors in either loads or SC-metered generation.
- ISO employees manually scan SC-reported data but have not caught all errors before settlement runs.

Impact:

- Very large imbalances (payments or charges) for individual SCs;
- Very large UFE amounts spread across other SCs.

Proposed preventive measures:

- Install screen for reported generation above 1000 MW per unit;
- Install screen for reported loads above 2-3 times scheduled loads, by zone.

Proposed correction:

- If preliminary settlement statements have not been issued, correct error and run settlements.
- If preliminary settlement statements have been issued, rerun and show corrections on final statements.