Supplementary Discussion of MRTU Market Parameters

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Market and Infrastructure Development Division

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Introduction

During 2008 the California ISO (ISO) discussed with stakeholders the conceptual foundations as well as the specific settings of a set of MRTU market parameters that are used for adjusting non-priced quantities in the market optimizations. The parameter values that resulted from these discussions were summarized in an ISO white paper published on October 29, 2008.[1] During the market simulation and structured testing that occurred since then, the ISO further evaluated the performance of additional configurable elements of the software and describes in this paper the nature of such elements and the proposed settings for the associated parameters.

Specifically, this paper discusses:

- Inter-interval ramping constraints, which govern how a generating unit's operational ramping capability can be shared between inter-interval energy schedule or dispatch changes and awards of ancillary services;
- RUC procurement constraints, which set limits on the amount of minimum load energy RUC can schedule through the commitment of resources that were not committed in the IFM, and on the amount of available short-start capacity that RUC can utilize;
- Protection of day-ahead ancillary services awards in the real-time market, through the setting of a scheduling parameter in the RTUC that limits the conversion to energy of day-ahead awards of ancillary services;
- Minimum effectiveness threshold for managing congestion, which prevents the use of extremely ineffective resource re-dispatch to relieve binding transmission constraints.

The ISO will hold a stakeholder conference call on Thursday, February 12 to discuss these parameters with stakeholders.

Inter-interval Ramping Constraints

The maximum amount of supply available to the ISO markets is generally thought of as the sum of the bid-in capacity of all generators and demand response resources. Because the market optimization honors resource performance constraints, however, the available supply in any given market interval is further constrained by available ramping capability. Modeling ramp rate constraints correctly is an important element of the MRTU market design that enables the ISO markets to produce feasible inter-interval schedule changes and dispatch instructions.

The MRTU design treats ramping constraints in a manner that balances the requirements of reliability, market supply and schedule feasibility.[2] The MRTU approach is implemented in the software as a pair of ramp rate constraints that apply to inter-interval energy schedules and ancillary services awards. These constraints apply to each generating unit during the ramping process between two consecutive market clearing intervals, in both the day-ahead and the real-

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1 See, "REVISED Update to CAISO Draft Final Proposal on Uneconomic Adjustment Policy and Parameter Values," revised October 29. 2008.

2 See ISO MRTU Tariff sections 31.3 and 34.5 and the ISO Business Practice Manual for Market Operations sections 6.6 and 7.1.

time markets. One constraint, in the upward direction, uses the resource's ramping capability to limit a weighted sum of its inter-interval energy schedule change or dispatch instruction and its regulation up, spinning, and non-spinning reserve awards. The second constraint, in the downward direction, limits a weighted sum of the resource's inter-interval energy schedule or dispatch change and its regulation down award.

The constraints are expressed as the following equations:

$$(p_{i,t}^{En} - p_{i,t-1}^{En}) + \alpha(p_{i,t-1}^{Ru} + p_{i,t}^{Ru}) + \beta(p_{i,t-1}^{Sr} + p_{i,t}^{Sr}) + \eta(p_{i,t-1}^{Nr} + p_{i,t}^{Nr}) \le RampRate(p_{i,t-1}^{En}) \cdot T$$

and

$$(p_{i,t}^{En} - p_{i,t-1}^{En}) - \alpha(p_{i,t-1}^{Rd} + p_{i,t}^{Rd}) \ge -RampRate(p_{i,t-1}^{En}) \cdot T$$

where,

$p_{i,t}^{En}$, $p_{i,t-1}^{En}$ = energy schedules of unit *i* in intervals *t* and *t-1*

$p_{i,t}^{Ru}$, $p_{i,t-1}^{Ru}$, $p_{i,t}^{Rd}$, $p_{i,t-1}^{Rd}$, $p_{i,t}^{Sr}$, $p_{i,t-1}^{Sr}$, $p_{i,t}^{Nr}$, $p_{i,t-1}^{Nr}$ = Regulation Up, Regulation Down, Spinning, and Non-Spinning Reserve awards to unit *i* in interval *t* and *t-1*

$RampRate(p_{i,t-1}^{En})$ = operational ramp rate of unit *i* at dispatch level $p_{i,t-1}^{En}$ (MW/minute)[3]

T = length of an interval (minute)

α, β, η = ramp-sharing coefficients.

These ramp rate constraints apply to all the MRTU markets, both day-ahead and real-time, but with different ramp-sharing coefficients depending on the length of the optimization interval in each market. The ISO's recommended coefficient values are listed in the following table.

Market	Interval Length (minute)	α	β	η
IFM	60	1.00	0	0
RTUC	15	0.75	0	0
RTED	5	0.25	0	0

The coefficient α has a positive value. This means that Regulation Up or Down has to compete with energy for the unit's ramping capability. This choice of coefficient value is based on operational reliability considerations. Specifically, it is important that the ISO retain the regulating capability of its supply of Regulation Reserve during the period of the inter-interval ramp, as this is often the time when Regulation Reserve is particularly needed. Setting this coefficient to zero and thereby sharing Regulation Reserve ramping with energy change ramping could significantly reduce the effectiveness of regulation to meet control performance.

In the MRTU markets a generating unit can be awarded Regulation Reserve in a MW amount that can be up to 10 minutes of its ramping capability in each interval. Thus in order to preserve

[3] The operational ramp rate is expressed as a constant value in order to simplify this exposition, but the actual software implementation utilizes the operational ramp rate function, which is a function of the unit's operating level.

100 percent of the unit's ramping capability to meet its awarded Regulation Reserve at all times in the IFM, it would be necessary to set α = 3.00. Ignoring for the moment any potential awards of spinning or non-spinning reserves, a setting of α = 3.00 means that the unit's ramping capability during the 60-minute period between the midpoint of hour t-1 and the midpoint of hour t will be sufficient to cover both its inter-hour energy schedule change and 100 percent of its Regulation Reserve awards in each hour, at all times during that period. With α = 1.00 in IFM, the inter-interval ramp rate constraints preserve ramping capability for up to 20 minutes within the 60-minute inter-hour period for the awarded Regulation Reserve in intervals t and t-1. This means that there is at least one-third of the average Regulation Reserve award across consecutive hours available at all times during the inter-interval ramp. Of course, if there is no inter-hour energy schedule change then all of the awarded Regulation Reserve is available at all times.

The RTUC has an interval length of 15 minutes, which is 75 percent of the 20 minutes maximum possible ramp capability that could be needed for the Regulation Reserve awards in intervals t and t-1. The setting of α = 0.75 will preserve sufficient ramp capability for awarded Regulation Reserve between two consecutive 15-minute RTUC intervals, without any ramp sharing between the Regulation Reserve award and the inter-interval energy schedule change.

The RTED has an interval length of 5 minutes, which is 25 percent of the 20 minutes ramping needed for potential Regulation Reserve awards. Setting α = 0.25 will preserve sufficient ramp capability for Regulation Reserve awards between two consecutive RTED intervals, also without the need for ramp sharing with the inter-interval energy dispatch change.

Setting β and η equal to zero means that operating reserves (Spinning and Non-Spinning) are able to share the unit's ramping capability with energy. That is, the unit can be awarded operating reserves up to its maximum ramping capability in an interval regardless of the size of its inter-interval energy schedule change. Stated another way, the award of operating reserves to the unit does not prevent its full ramping capability from being used to move between operating levels in two consecutive intervals. However, the total A/S award in the upward direction (the sum of Regulation Up, Spinning, and Non-spinning) or downward direction (Regulation Down) to each generating unit cannot exceed its 10-minute ramp capability.

The coefficient values in the table above have been set based on the outcomes of MRTU testing process. In the course of testing it was found that if the values are set too high – for example if all three coefficients are set to equal 3.0 in the IFM constraint equations – there will be no ramp sharing between the energy schedule change and the provision of ancillary services. As a result the market will use the available resources most conservatively and will create unnecessary transitory shortage conditions. In the worst cases observed, the market was extremely short of supply in certain hours and had to curtail demand dramatically in order to reach a solution.[4]

Constraints on RUC Procurement

As described in the Business Practice Manual for Market Operations, section 6.7, the IFM clears the market based on submitted self-schedules and economic bids, and may clear at a

[4] The recent FERC order on the Midwest ISO Ancillary Services Market accepted the similar concept of ramp sharing for the Midwest ISO Ancillary Services market design. ORDER AUTHORIZING MIDWEST ISO ANCILLARY SERVICES MARKET START-UP, Docket No. ER09-24-000 (Dec. 18, 2008)

significantly lower overall level than the CAISO Forecast of CAISO Demand (CFCD) for some or all hours of the next day. The RUC process assesses the resulting gap between the IFM scheduled load and the CFCD, and ensures that sufficient capacity is available for dispatch in real-time. The RUC process may commit and issue start-up Instructions, as well as identify additional unloaded capacity from resources that were committed in the IFM.

The RUC optimization is similar to the IFM optimization, but has several distinctions including incorporation of additional operational constraints using solution parameters that are described in section 6.7.2.7 of the BPM. The ISO currently uses the following values for the parameters associated with these constraints.

- Maximum Energy Constraint. When RUC commits capacity, additional energy will be produced by the resource's operation at its minimum load which will contribute toward meeting the RUC procurement target. In order to reduce the possible over-scheduling of energy in RUC when trying to meet the target, RUC limits the total quantity of IFM energy schedules plus RUC minimum load energy to be less than a configurable percentage of the total RUC procurement target. The BPM describes the initial range for the RUC Maximum Energy Constraint to be between 95% and 100% of the target. The CAISO has found through market simulation testing that when this value is set too low (e.g., below 95%), the RUC optimization can fail to commit Resource Adequacy (RA) resources in order to avoid scheduling their minimum load energy, and instead will reserve additional non-RA capacity from already-committed generators. This has been particularly noticeable in market simulation hours where the IFM cleared at levels close to 95% of the CFCD. To avoid this result, while allowing a tolerance for estimation error in setting the RUC procurement target, the CAISO now sets the RUC Maximum Energy Constraint to 99% of the target.
- Short-Start Unit Capacity Limit. In order to limit RUC from relying excessively on the capacity of short-start units, the ISO limits the amount of available short-start capacity that RUC can utilize. The BPM describes the initial range to be between 75% and 100% of total short-start unit capacity, and described certain considerations – historical confidence that a short-start unit actually starts when needed, conserving the number of run-hours and start-ups per year for critical loading periods, and seasonal constraints such as over-generation – as operational factors that provide a rationale for reducing the short-start unit limit below 100%. To provide conservative operation during the initial months of MRTU, the ISO will initially set the short-start unit capacity limit to 75%.

Protection of day-ahead ancillary services awards in the real-time market

Initially in MRTU market simulation, day-ahead AS awards were protected from curtailment in the RTUC (RTPD) energy and AS co-optimization as hard constraints, meaning that the optimization could not reduce them under any circumstances. Such extreme protection was found to result in solution infeasibility in market simulation, due to the fact that changes to resource operational conditions in real-time could make it impossible for the resource to support the full amount of AS that has been awarded in the day-ahead market. In such cases, the unresolvable resource constraint prevented the market from reaching a feasible solution. The ISO therefore recognized that the software must allow for curtailment of day-ahead AS awards in the RTPD through the use of penalty prices.

Once this was realized, the more recent market simulations of RTPD have been run using relatively low scheduling run penalty prices in the region of $600-700 in absolute value (note that penalty prices for protecting day-ahead AS awards are negative in value). With such relatively low penalty price values, RTPD market simulation results show that curtailments of day-ahead AS for energy scheduling are not uncommon and can occur when the LMP at the relevant resource location rises towards $1000.

The ISO recognizes that curtailing day-ahead AS awards is undesirable, especially for those AS flagged as contingency and supported by use-limited resources. At the same time, it has been shown to be necessary to be able to curtail day-ahead AS awards when the supporting resource is unable to provide its day-ahead AS award, so retaining the original hard constraint is not an acceptable solution either. In order to balance these two objectives, the CAISO proposes penalty prices for day-ahead AS awards in the RTPD. Note that these parameters in absolute value exceed the $6500 penalty price for energy balance in the real-time market. Also listed in this table is the penalty price for load following reserve self-provision, which is relevant for Metered Subsystems (MSS) electing the to follow their own real-time load. Qualified load following self-provision up and down are assigned -$8500 penalty price as protection of such self-provision takes precedence over other categories of AS self provision including day-ahead AS awards.

RTPD Penalty Price Description	Scheduling Run Value	Pricing Run Value
Day ahead conditionally qualified Reg Up or Down award	-7750	NA
Day ahead conditionally qualified Spin award	-7700	NA
Day ahead conditionally qualified Non-Spin award	-7650	NA
Qualified Load Following Up or Down	8500/-8500	NA

Minimum Effectiveness Threshold

In response to the ISO's November 4, 2008 FERC filing on the market parameters, some parties argued that the process of adjusting non-priced quantities should contain a minimum effectiveness threshold, i.e., a minimum percentage of effectiveness for a resource that would be used to relieve congestion on a particular constraint. Without a minimum effectiveness threshold, it was argued, the software could accept extremely ineffective resource adjustments to relieve a constraint, which could result in large quantities of energy bids at low prices being adjusted in the IFM.

In its December 12, 2008 reply the ISO acknowledged that without a lower limit on effectiveness the market software could accept significant quantities of low-priced energy bids to achieve a small amount of congestion relief on a particular constraint. The ISO noted further that the MRTU software does have a lower effectiveness limit setting which can be specified by the ISO at a level that will produce congestion management scheduling results consistent with good operational practice. At the time of that filing the lower effectiveness limit was set in the market simulation software at 0.5 percent effectiveness (i.e., 0.005), which prevented the optimization from adjusting the schedule of a resource that was less effective on any particular constraint in order to relieve congestion on that constraint.

As the ISO noted in the December filing, for most of the prior market simulation process the lower limit had been left at the factory default setting of 0.01 percent effectiveness (i.e., 0.0001), and had only recently been raised to 0.5 percent to allow the ISO to assess how it would affect market scheduling solutions. Thus the ISO could not, at that time, provide its recommendation for the MRTU start-up value of this parameter. Now, after the additional weeks of testing at the higher parameter value, the ISO is confident that 0.5 percent is a prudent and appropriate value for the minimum effectiveness threshold. What this setting does in effect is to reduce slightly the set of allowable re-dispatch solutions for relieving congestion on a given constraint, to eliminate those solutions that would be operationally unsound because they include the use of highly ineffective resource adjustments which an operator following good utility practice would not use.