



## *Market Participants and Stakeholders;*

The ISO is posting the accompanying Revised Comprehensive Market Design Proposal: Final Draft to give stakeholders an opportunity to review the elements of the revised design in its entirety. ISO Management will be asking for approval of this Revised Comprehensive Market Design Proposal at the June 6, 2003 Board of Governors meeting. In this posting no effort is being made to represent the positions of various parties or the process by which the final design elements were developed. Most components have been discussed in one form or another at various stakeholder forums, including comments and protests submitted to the Federal Energy Regulatory Commission (FERC).

This is the first instance in which the revised design in its entirety is being presented to stakeholders. The ISO acknowledges that resolutions of some of the outstanding elements are being put forth for the first time in this posting and others are modified from previous representations to stakeholders. The ISO internal design team has carefully considered both the input of the various stakeholders and the objectives and integrity of the overall design in developing these final recommendations. Taken in their entirety, they provide the foundation for a workable wholesale competitive market and meet the core ISO mission of providing reliable, open and non-discriminatory electric transmission service to the users of the ISO grid.

We hope that you take this limited period for comment to consider the design as a whole, and provide us feedback on that basis, including alternatives. We recognize that there may be specific elements that you might disagree with. If you wish to make comments on the document, please submit in writing by 4:00 p.m. Pacific Daylight Time on Monday, June 2, [MD02comments@caiso.com](mailto:MD02comments@caiso.com).

**FINAL DRAFT**

**California Independent System Operator  
Market Design 2002 Project (MD02)**

**REVISED**

**Comprehensive Market Design  
Proposal**

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**May 27, 2003**

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## 1 Introduction

On May 1 and June 17, 2002, the ISO filed its Market Design 2002 (MD02) Comprehensive Market Design Proposal and associated modifications to the ISO Tariff, respectively. In those filings the ISO proposed a three-phase implementation approach which has been retained in the present Revised Comprehensive Design Proposal. Subsequent to those filings the Commission issued several orders regarding the implementation of Phase 1, pursuant to which the ISO has already implemented Phase 1A and is in the process of implementing Phase 1B.

In addition to issuing orders on Phase 1 the Commission convened a technical conference in August 2002 as an initial forum for discussing several aspects of Phases 2 and 3 of MD02 with stakeholders. The participants in this technical conference agreed to form four Stakeholder Working Groups, each having a scope defined to address specific MD02 design elements, which met throughout the fall of 2002. Through the process of these working groups and some subsequent stakeholder activities convened by the ISO, the MD02 proposal received significant clarification and elaboration as well as some modification. As a result it is now appropriate for the ISO to amend the May 1 and June 17, 2002 MD02 filings and present the Commission with a complete description of Phases 2 and 3 of the MD02 Comprehensive Design as the ISO now proposes to implement them. The present document provides such a description.

Due to the procedural and implementation bifurcation of Phase 1 from the rest of MD02 over the past year, the present document focuses exclusively on Phases 2 and 3, and refers to Phase 1 elements only when needed to explain how the phases will function together or to describe any enhancements to Phase 1 elements that are needed for consistency with Phases 2 and 3. At the same time, the present document is a complete description of Phases 2 and 3 of the MD02 Comprehensive Design and as such is intended to be self-contained without requiring any reference to the discussions of these Phases in the earlier MD02 filings.

In order to provide as clear and concise a description of the revised Phase 2 and 3 proposal as possible, the present document does not contain any explanation of alternative design options the ISO considered nor any of the rationale or arguments to support the ISO's design decisions and proposals contained herein. These other materials, as well as detailed discussions of the viewpoints and concerns expressed by stakeholders throughout the MD02 design process, are provided in the transmittal letter that accompanies the present document in the ISO's filing of this proposal with the Commission.

## 2 The Revised MD02 Comprehensive Design Proposal

### 2.1 Must Offer Obligations

1. The term "Must Offer Obligations" (MOO) refers generically to any set of specific obligations on supply resources to participate or be scheduled in the ISO's markets and be available to the ISO for real-time dispatch, irrespective of whether these obligations derive from a resource adequacy program regulated by the state, a capacity requirement administered by the ISO (e.g., ACAP or ICAP), or FERC orders (as in the current situation). MOO prevent the exercise of market power through physical withholding of supply resources. However, depending on the regulatory basis for MOO, they may or may not include an obligation to serve load within the ISO control area. Supply resources that are subject to MOO are referred to as "Must Offer Resources."

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2. Under a future state resource adequacy program or ISO-administered capacity requirement, MOO will apply to all supply resources (including demand response) that are designated as fulfilling the resource adequacy or capacity requirements of a responsible entity.<sup>1</sup> In this case MOO would go beyond participation in ISO markets and would require being available to serve ISO control area load. MOO may be established, for example, through standard contractual provisions between suppliers of capacity and the entities responsible for procuring that capacity.
3. In the near term, since a resource adequacy program or capacity requirement will not likely exist when the ISO's proposed Integrated Forward Market (IFM) is first implemented, MOO will derive from the FERC market mitigation orders that are in effect today, with some modifications as described below that are needed to support the MD02 design. Today the FERC-imposed MOO apply to all non-hydro units within California that use the ISO Controlled Grid or participate in ISO markets.
4. Under the present proposal, Must Offer Resources will be required to bid or schedule their entire operable capacity into the Day Ahead and Hour Ahead integrated forward markets (IFM) to be committed and scheduled for energy, be available for commitment by the ISO in the Day Ahead and Hour Ahead Residual Unit Commitment (RUC) process, and be available for real-time dispatch by the ISO to the full extent of their operable capacity. Although MOO will not require participation in the forward A/S markets, self-scheduling or bidding A/S will count towards satisfying MOO. The current MOO require only that such resources bid their available capacity into the ISO's Real Time market.
5. There are some accommodations and exceptions to this MOO proposal, for example, to allow resources with legitimate use limitations (e.g., emissions-constrained resources or hydro resources designated as meeting capacity obligations) to be managed in a manner consistent with their limitations. Such exceptions are described later in this document.

## 2.2 Integrated Forward Markets Based on Locational Marginal Pricing

### 2.2.1 Introduction

6. The ISO proposes to implement Day Ahead and Hour Ahead **Integrated Forward Markets (IFM)** based on the **Locational Marginal Pricing (LMP)** paradigm.
7. The IFM will utilize a **Security Constrained Unit Commitment (SCUC)** algorithm with a bid-cost minimization objective function and will include:
  - Congestion management using a **Full Network Model (FNM)** that represents all the transmission constraints, including nomograms,<sup>2</sup> that the ISO must respect in Real Time, and thus eliminates the current distinction between inter-zonal and intra-zonal congestion;

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<sup>1</sup> Under the ISO's original ACAP proposal as contained in the May 1, 2002 MD02 filing, the entities responsible for resource adequacy would be the load-serving entities (LSEs). At this time the ISO does not want to presume that LSEs will be the responsible entities, to the exclusion of other potentially effective ways to allocate responsibility for resource adequacy. The present proposal therefore assumes only that there will be specific entities charged with such a responsibility.

<sup>2</sup> Nomograms are a device for representing operating limits on transmission facilities that cannot be expressed as individual thermal constraints on individual pathways, such as relationships between flows on multiple pathways as well as dynamic and voltage support requirements.

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- An energy market that eliminates the Market Separation Rule and the balanced schedule requirement, clears all economic demand and supply bids while treating self-schedules as price takers, and produces locational marginal prices at the nodal level (“nodal pricing”);
  - Simultaneous procurement of Ancillary Services (A/S, including Regulation Up, Regulation Down, Spinning and Non-spinning Reserves) along with energy clearing and congestion management; and
  - Commitment of supply resources to serve demand that is self-scheduled or cleared in the Day Ahead or Hour Ahead IFM.
8. Consistent with adoption of the LMP paradigm and nodal pricing the ISO proposes to create a new **Congestion Revenue Rights (CRR)** instrument for hedging congestion risks, to replace the ISO’s existing Firm Transmission Rights (FTR) instrument.
  9. The ISO proposes to perform, following the running of the Day Ahead and Hour Ahead IFM, a **Residual Unit Commitment (RUC)** procedure as a reliability backstop to ensure that any supply resources not scheduled in the IFM but needed for reliable and secure Real Time operation will be given adequate notice to enable them to be on-line and available for real-time dispatch. In contrast to the IFM, which clears based on SC schedules and bids, the RUC procedure will be based on the ISO’s load forecast and will target the gap between that forecast and the quantity of load scheduled in the previous IFM.
  10. The ISO proposes to implement the new market design in three phases. It is important to realize, however, that the MD02 proposal is a comprehensive, integrated design and that this phased approach – particularly the separation of Phases 2 and 3 – is intended only to facilitate efficient and realistic system implementation and testing. Specifically, the ISO does not view Phase 2 as a viable market design in its own right and therefore intends to minimize as far as practical the time between Phases 2 and 3. This document is therefore crafted to describe the complete design (i.e., with all phases implemented), with specific discussion added where needed to clarify rules or features that will apply in the interim between phases.
    - Phase 1 elements include market power mitigation (Phase 1A) and real-time **Security Constrained Economic Dispatch (SCED)** with financial disincentives (or “uninstructed deviation penalties”) for uninstructed deviations (Phase 1B). Phase 1A was implemented in October 2002, and Phase 1B will be implemented in October 2003. The Phase 1 elements are considered to be part of the comprehensive design, but are not discussed in any detail in the present document except where they need to be enhanced to be consistent with Phases 2 and 3.
    - Phase 2 will establish the IFM using the ISO’s current three-zone radial network model, but will eliminate the market separation rule and the balanced schedule requirement.
    - Phase 3 will be implemented shortly after Phase 2 and will complete the new design by installing the FNM and establishing nodal LMP and the new CRRs. At this time the FNM would be implemented in the Real Time market as well as the forward markets.
  11. A number of special provisions will apply to Metered Subsystems (MSS), primarily to allow them some options with regard to participation in ISO markets. These are explained in a separate section of this proposal which will be available in the near future. It is important to note that to the extent MSS participate in ISO markets, unless a special provision is explicitly stated in the MSS section, all elements of this proposal apply to MSS in the same manner as they do to other ISO grid users and market participants.

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12. Scheduling Coordinators (SCs) will submit Preferred Schedules to the IFM that may consist of any of the following. For the purposes of this document, the term “bid” will be used to refer to an energy or capacity quantity with an associated price, whereas “self-schedule” will refer to a submitted energy or capacity quantity with no associated price. (The actual structure of bids and the ISO’s validation procedures are discussed in more detail below.)
- Supply bids – bids to supply energy or A/S capacity at no less than specified prices. A/S capacity may be provided by qualified supply-side and demand-side resources.
  - Demand bids – bids to purchase energy at no more than specified prices.
  - Energy self schedules – preferred quantities of energy supply or demand submitted without associated energy bids. Submitted self schedules may be balanced (supply equal to demand) or not. Even if they are submitted balanced, however, the absence of a Market Separation Rule means there is no guarantee that they will remain balanced after the running of the IFM. Supply resources may be submitted partially as self schedules (e.g., as a preferred operating level below P-max with no decremental (DEC) bids) and partially as bids (e.g., incremental (INC) bids for the capacity above the self-scheduled level). (Treatment of self schedules is described in more detail below.)
  - A/S self provision nominations – supply-side or demand-side A/S capacity offered for A/S self provision.
13. The proposed IFM will adjust generation, load, import and export schedules and clear energy and A/S supply and demand bids to manage congestion using a SCUC that respects linearized transmission constraints identified by an AC-based power flow and contingency analysis algorithm and a full network model (FNM) that includes all transmission network busses and transmission constraints, and possibly a reduced network representation of the rest of the WECC system.
14. Market power at the system level will be mitigated by: (a) a Damage Control Bid Cap (DCBC), which is a “soft” bid cap that allows bidders to bid and be paid above the DCBC (subject to refund if they cannot cost-justify their bids), but does not allow them to set prices. Initially the DCBC will be kept to the current level of \$250/MWh for energy and \$250/MW for A/S capacity; (b) a bid floor at -\$30/MWh; and (c) extension of the automatic mitigation procedure (AMP), currently in effect today for the Real Time market, to the IFM and RUC procedures. Local market power will be mitigated by the use of Reliability Must Run (RMR) contract resources and a PJM-style mitigation procedure integrated into the IFM as described later in this document.
15. The nodal prices resulting from the LMP-based IFM will consist of three components: energy, congestion, and transmission losses. For any given dispatch period (an hour in the forward markets; five minutes in the Real Time market), the energy component will be the same at all nodes in the system (i.e., the cost of energy to the system in the absence of congestion and losses). Therefore the differences between nodal prices will represent the costs of congestion and transmission losses between the corresponding nodes.
16. The ISO proposes to aggregate busses to create aggregation points such as trading hubs to facilitate energy trading and load aggregation zones to simplify load scheduling, bidding and settlement and to insulate consumers from potentially high nodal prices in constrained areas of the grid. As described below, most loads within the ISO control area will be settled at aggregate prices that are averages of nodal prices over the existing transmission service areas of the investor-owned utilities (IOUs).

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17. Because the nodal prices produced by the IFM can exceed the DCBC in the presence of congestion and inelastic load, the aggregate prices used for settlement of aggregated loads will be capped at the level of the DCBC, i.e., \$250/MWh initially. If this results in revenue shortfall due to compensating generators at the actual nodal prices, the difference will be recovered through an uplift. The ISO will publish the actual nodal prices, as these prices provide the most accurate information on the cost of congestion on the grid to be used for planning investment in transmission and demand response and the location of new generation.
18. The IFM will produce final schedules that are feasible with respect to all transmission constraints modeled in the FNM, including nomograms, as well as generator ramping, inter-temporal and other performance constraints,<sup>3</sup> and will eliminate the current distinction between inter-zonal and intra-zonal congestion.

**2.2.3 Bid Structure and Validation**

19. Supply bids will have a three-part structure, consisting of (a) start-up cost, (b) minimum load cost, and (c) incremental energy curve. In addition supply bids may include a capacity bid to supply any A/S for which the resource has been certified. For purposes of bidding to supply energy or Non-spinning Reserve, participating loads will use the same bid structure as other supply resources.
20. The start-up cost component of the bid (expressed as \$/start-up) may range from zero up to the unit's estimated start-up cost,<sup>4</sup> which will be calculated by the formula:
  - Start-up cost = (start-up fuel consumption \* GPI) + (start-up auxiliary energy consumption \* EPI), where GPI = gas price index and EPI = electricity price index.
  - The start-up fuel and start-up auxiliary energy consumption will be actual physical parameters of the unit. The GPI will be the same monthly weighted average gas price that is used for calculation of proxy bids. The EPI will be the electricity tariff rate charged by the distribution utility where the unit is located. The EPI will be determined on a case-by-case basis and will consider whether the unit pays a wholesale or retail rate or some combination.
  - Demand-side resources are not restricted to cost-based bids for start-up, but will be required to have established maximum values for their start-up cost on file with the ISO.
  - System Resources (supplies offered over the inter-ties) are not allowed to submit start-up bids.

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<sup>3</sup> The proposed concept of feasibility does not, however, require that final schedules reflect actual levels of load and generation expected in Real Time. Feasibility in this document means simply that the final scheduled injections and loads do not violate any modeled transmission constraints and are consistent with resource performance parameters as contained in the ISO's Master File. To the extent that all expected real-time load does not appear in a final schedule, any shortfall between schedules and the ISO's load forecast is addressed by the ISO's residual unit commitment, discussed below.

<sup>4</sup> With respect to start-up and minimum load costs the ISO notes that the PJM approach is a viable alternative and is considering allowing market participants the flexibility of choosing this option. Under the PJM approach the start-up and minimum load cost components of the bid are market bids that remain fixed for a six-month period once they are submitted and are always used as the resource's start-up and minimum load bids in all ISO markets in which the resource participates. Thus, once the resource submits these bids, the resource does not have the flexibility to submit a different value in any given ISO market, in contrast to the cost-based approach described in the text.



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21. The minimum load cost component of the bid (expressed as \$/hour) may range from zero up to the unit's estimated minimum load cost, which will be calculated by the formula:
  - Minimum load cost = average heat rate at minimum load \* GPI \* minimum load MW.
  - The average heat rate at minimum load will be the actual physical parameter of the unit.
  - Demand-side resources are not restricted to cost-based bids for minimum load, but will be required to have established maximum values for their start-up cost on file with the ISO.
  - System Resources (supplies offered over the inter-ties) are not allowed to submit minimum load bids.
22. The incremental energy supply bid curve, indicating the prices in \$/MWh at which a resource is willing to supply various quantities of energy in MWh, must be an increasing staircase function composed of not more than 20 segments. The incremental energy bid curve is not limited to be within the unit's estimated costs, but bids must comply with activity rules regarding changes between successive markets and may be subject to mitigation under certain circumstances as described elsewhere in this document.
23. The demand bid curve, indicating the prices in \$/MWh at which a buyer is willing to purchase various quantities of energy in MWh, must be a decreasing staircase function composed of not more than 20 segments.
24. Capacity bids to supply A/S will indicate the price in \$/MWh at which a resource is willing to supply a specified quantity of A/S in MW. The supplier may submit a different single value bid price and quantity for each service (Regulation Up, Regulation Down, Spin and Non-spin) for which the resource has been certified.
25. The ISO will generate unit-specific Proxy Bids for each Must Offer resource, which the ISO will insert into the relevant market in instances where the resource fails to bid or schedule its full capacity in accordance with its MOO. Proxy bids will be based on resource costs on file with the ISO. Proxy bids will include incremental energy cost curves based on the resource's incremental heat rate, as well as start-up and minimum load costs if the ISO has these on file. In the event that a Must Offer resources fails to bid and the ISO does not have its cost-based start-up and minimum load costs on file, the ISO will insert \$0 values for these.
26. The ISO will support inter-SC trades as a convenient method for two SCs to exchange payment responsibilities with respect to ISO charges. Inter-SC trades may be for energy or A/S, must occur at a specific grid location (which may be an aggregation point), and must be submitted by both trading parties in a consistent manner. An inter-SC trade will thus consist of an injection and an equal withdrawal at the same location and will therefore have no congestion impact on the grid.
27. When Preferred Schedules are submitted the ISO will perform validation of several bid components, including: conformance to bid structure requirements and bidding activity rules; compliance with applicable bid caps; consistency between submitted generator performance parameters and the corresponding values contained in the Master File; the ability of the resource to meet self-scheduled inter-hour ramping requirements; the ability of the resource to perform in accordance with submitted A/S bids and self provision; and, consistency between the two sides of an inter-SC trade as submitted by the two trading SCs.

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28. The ISO proposes eventually to utilize, in the forward markets and in Real Time, a full network model (FNM) that accurately represents constraints and interfaces of the ISO-controlled grid and incorporates a model of the WECC regional grid external to the ISO control area. The external model will be a “closed-loop” model that represents external electrical connections between the various inter-ties into the ISO control area, and thus allows the ISO to explicitly estimate and manage parallel path or “loop” flows in coordination with other control areas in the region. Most significantly, the closed-loop FNM will accurately model loop flows due to internal resources and will result in accurate scheduling and dispatch of these resources to address congestion within the ISO-controlled grid.
29. Implementation of a FNM that incorporates a “closed loop” approach is dependent on the availability and use of modeling data and forward energy schedules throughout the western interconnected region. The ISO will be prepared to implement this approach. However, explicit forward scheduling in a manner that accounts for loop flows may create severe problems if the ISO were to adopt this feature ahead of its neighbors throughout the west. Therefore, when Phase 3 is first implemented, the ISO may need to use a simpler “open-loop” representation of the external network, until such time as there is an effective, coordinated western regional framework for Day Ahead scheduling and congestion management, including explicit scheduling of inter-control area parallel path flows.

**2.2.5 Treatment of Self Schedules**

30. SCs who want to self schedule demand or supply at a specific operating level rather than be committed or dispatched in the IFM based on market bids may submit preferred schedules, balanced or not,<sup>5</sup> with no bids, or with bids that do not extend down to 0 MW (e.g., INC bids but no DEC bids relative to a non-zero operating level).<sup>6</sup> Under MD02 a “self schedule” is defined as any portion of a preferred schedule submitted without associated energy bids. Since self schedules do not have any bids associated with their energy quantities, they are price takers and cannot be used to set market-clearing prices.
- Self schedules that utilize ETC rights or the scheduling priority of CRRs (which applies only to the demand side of CRR schedules, and only in the Day Ahead market) must be submitted balanced.<sup>7</sup> (If the SC submits both CRRs and demand-side adjustment bids with a preferred schedule, the IFM will utilize the bids and will ignore the scheduling priority of the CRRs for that schedule.)
  - Wheeling schedules (i.e., matched import and export schedules), with or without bids, must also be submitted balanced.
31. The IFM will perform simultaneous resource commitment, congestion management, energy market clearing and A/S procurement to minimize total bid cost using three-part energy bids and A/S capacity bids, giving scheduling priority to all self schedules and A/S self provision in accordance with a hierarchical priority sequence described below.

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<sup>5</sup> Under MD02 a “balanced” schedule is one in which total supply equals total demand, taking into account any inter-SC energy trades, without any explicit allowance for losses.

<sup>6</sup> For example, a generator whose maximum output is 200 MW may self schedule 120 MW of its capacity and bid the other 80 MW into the IFM by submitting a preferred operating level of 120 MW with 80 MW of INC bids and no DEC bids. The first 120 MW would be a self schedule under the MD02 definition, while the remaining 80 MW with associated energy curve would constitute a bid.

<sup>7</sup> Wheeling schedules, with or without bids, must also be submitted balanced.

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32. The Day Ahead IFM will observe the following scheduling priority sequence (from higher to lower priority) in clearing supply and demand and managing congestion: (1) supply and demand associated with ETC schedules; (2) self-scheduled demand associated with CRR schedules and self-scheduled supply from Must Take and Must Run resources (only the portion associated with Must Take or Must Run status); (3) any other self schedules (supply and demand without energy bids); and (4) supply and demand with energy bids.
33. The Hour Ahead IFM follows a somewhat different hierarchy, due to the incremental nature of the Hour Ahead market, the absence of CRR scheduling priority, and the proposed treatment of ETCs in this market (discussed in more detail later in this document). Final Day Ahead schedules have the highest scheduling priority in the Hour Ahead market. A resource scheduled in Day Ahead may, however, submit bids to sell or buy back in the Hour Ahead market. The Hour Ahead IFM will observe the following scheduling priority sequence (from higher to lower priority) in clearing supply and demand and managing congestion: (1) final Day Ahead schedules without energy bids in the Hour Ahead market; (2) Hour Ahead supply and demand deviations associated with ETC schedules; (3) Hour Ahead self-scheduled supply deviations from Must Take and Must Run resources (only the portion associated with Must Take or Must Run status); self schedules for the energy from System Resources and the minimum load energy from generating units and Participating Load that were selected and committed in the Day Ahead RUC; (4) any other Hour Ahead self-scheduled deviations (supply and demand deviations without energy bids); and (5) Hour Ahead supply and demand deviations with energy bids.
34. Self scheduling and the use of daily energy limits provide a way for a resource owner to manage any use limitations on that resource. For example, a resource may submit a use limitation for the next day and allow the IFM to schedule it in the most effective way over the 24 hours of the day while respecting the use limitation. With regard to use-limited resources that are also Must Offer resources, the ISO must be able to verify use limitations and ensure that the resource owner is fully complying with its Must Offer Obligations by providing to the ISO all capacity that is available within its verifiable use limits. The ISO proposes to work with resource owners to establish data requirements for use-limited resources to assure transparency and clarity of standards for compliance with Must Offer Obligations, to achieve the objectives of (1) equitable treatment of all Must Offer resources, (2) access to all opportunities for market transactions, and (3) reliable operation of the transmission system.

**2.2.6 Market Power Mitigation and Local Reliability**

35. Adopting a market design centered around a LMP-based IFM requires several modifications to the existing provisions for mitigation of market power both at the system level and at the local level. At the local level the market power problem is intimately linked to local reliability needs, and thus to the use of Reliability Must Run (RMR) resources. Under the current zonal market design the ISO relies exclusively on RMR for forward management of local reliability where RMR units exist, and issues dispatch instructions to any non-RMR resources needed for local reliability beyond what is available from RMR only in Real Time. MD02 therefore includes provisions to deal fully with local congestion and reliability needs in the forward markets. This section describes the sequence of steps and procedures whereby system and local market power mitigation and local reliability considerations, including the use of RMR, will be incorporated into the IFM. A later section of this document provides further details on the ISO's proposed local market power mitigation approach, including criteria for mitigating the bids of specific units and determining the appropriate levels of mitigated bids.

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36. The ISO will continue to impose a Damage Control Bid Cap (DCBC) at the current level of \$250/MWh for energy and \$250/MW for A/S capacity. The DCBC also provides a lower limit on bids at -\$30/MWh. The DCBC will be a soft cap, which means that suppliers may bid and be paid above the DCBC (subject to refund if they are unable to cost-justify such bids), but such bids will not be used to set prices.
37. The ISO will continue to employ the Automatic Mitigation Procedure (AMP) in Real Time to mitigate market power at the system level (System AMP), and will extend its use to the forward markets (Day Ahead and Hour Ahead). The sequence of steps and procedures by which System AMP will be incorporated into the forward markets is described in this section.
38. System and local market power mitigation procedures and determination of RMR dispatch levels will be performed in a sequence of pre-processing IFM runs in the Day Ahead and Hour Ahead time frames. These "Pre-IFM Reliability and Market Power Mitigation" runs (Pre-IFM-RMPM) will occur for the Day Ahead market at 10:00 A.M., after all bids and schedules are submitted to the ISO. The Pre-IFM-RMPM runs will optimally dispatch resources as if they were procuring energy and ancillary services to meet 100 percent of the ISO's demand forecast, rather than utilizing scheduled and bid demand. Using the forecast is appropriate because the needs for RMR dispatch and market power mitigation will ultimately depend on actual demand, not just on the demand scheduled and bid in the IFM. Of course, the actual IFM dispatch for forward scheduling and settlement purposes will be based on scheduled and bid demand after these Pre-IFM-RMPM runs are concluded, as described below.
39. There will actually be two Pre-IFM-RMPM runs, one in which only competitive network constraints<sup>8</sup> are enforced and a second run in which all network constraints modeled in the FNM are enforced. Comparing the unit dispatch levels between the first and second runs will determine RMR pre-dispatch levels and will identify the units to be subject to local market power mitigation. System market power mitigation (System AMP) will be performed in the first Pre-IFM-RMPM with only the competitive network constraints enforced. The detailed procedures for each Pre-IFM-RMPM run are described below.
40. The first Pre-IFM-RMPM run will enforce only competitive constraints (Pre-IFM-RMRM-CC) and will be based on the ISO's load forecast. Market bids and self schedules will be used for all non-RMR units and Condition 1 RMR units. All Must Offer units, including Condition 1 RMR, submitted to the IFM without bids will be entered with proxy bids or proxy extensions for the amount of capacity not bid. Condition 1 RMR units that are not Must Offer resources will be considered only if they submit bids. Condition 2 RMR units will not be considered.

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<sup>8</sup> Initially these will be Path 15, Path 26 and the Inter-ties, plus local transmission constraints in local generation pockets pre-designated as competitive (e.g., Miguel substation). Transmission constraints out of major generation pockets are considered competitive because in a nodal market structure, generators within these pockets will compete for the right to get out of the pocket. The current zonal design creates non-competitive situations in generation pockets in the real-time market because it allows infeasible schedules in the forward market. This will not be the case under a nodal market design. Furthermore, modeling transmission constraints out of major generation pockets in the first Pre-IFM run ensures that any positive incremental dispatches in the second Pre-IFM run, where all transmission constraints are enforced, are due to relieving congestion on non-competitive paths rather than the result of re-dispatching infeasible generation schedules from resources located in generation pockets. This initial set of competitive constraints may be expanded after the start of the LMP market. The evaluation process and criteria for designating constraints competitive are discussed in the section on Local Market Power Mitigation. A revised set of competitive constraints in the future may include some large load pockets that have sufficient competition among generation owners.

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System Market Power Mitigation (SMPM) will be applied during this run. Specifically, units that violate the System AMP conduct thresholds will be mitigated to their reference levels for the entire range of the resource capacity and tested for market impact. The market impact test will require running the Pre-IFM-RMPM-CC a second time and comparing market prices from this run to the previous unmitigated run. If the bid mitigation did not produce a material impact on market prices the initial unmitigated run will stand. Otherwise the mitigated run will stand along with mitigated bids for the entire capacity of the mitigated resources. Bids and schedules from the accepted Pre-IFM-RMPM-CC run will be used as a starting point in the next stage of the Pre-IFM-RMPM in which the full network model is imposed.

41. The second Pre-IFM-RMPM run will enforce all constraints (Pre-IFM-RMPM-AC) and will also be based on the ISO's load forecast. All constraints modeled in the FNM will be enforced whether competitive or non-competitive, including nomograms and dynamic and voltage support dispatch requirements (such as minimum local generation in a load pocket) as predetermined by ISO Operating Engineers and RMR Dispatchers.

As noted above, bids and schedules from the accepted Pre-IFM-RMPM-CC run will provide the starting point for this run, with the following specifications:

- DEC bids (i.e., bids to move units below the scheduled amounts derived from the Pre-IFM-RMPM-CC run). Accepted bids from generation and import schedules from accepted Pre-IFM-RMPM-CC run are replaced with very high negative penalty DEC bids.<sup>9</sup> To preserve the relative merit order of these bids the penalty price will be applied as an adder to the original bid (e.g., original bid minus \$10,000). In addition to adjustments based on bids, it may be necessary to reduce the scheduled output of some self-scheduled resources to manage congestion in this step. In this case the ISO will assign higher DEC penalty prices to observe the scheduling priorities assigned to Must Take and Must Run resources, consistent with the section on "Treatment of Self Schedules" elsewhere in this document. Note, however, that at this point in the IFM process RMR units are not yet treated as Must Run since the required RMR dispatch levels have not yet been determined.
  - INC Bids (i.e., bids to move units above the scheduled amounts derived from Pre-IFM-RMPM-CC run):
    - INC bids for Condition 2 RMR units will be set at the level specified in Schedule M of the RMR Agreement for cost-based bid prices up to the Unit Availability Limit, i.e. full available capacity (the "RMR Price").
    - INC bids for Condition 1 RMR units will be set at the lower of the RMR price or the submitted market bids (to determine the required RMR dispatch).
    - INC bids for all non-RMR units will be the bids resulting from the previous Pre-IFM-RMPM-CC run (i.e., submitted market bids or bids mitigated under System AMP).
42. It is important to note that the resources committed in the Pre-IFM-RMPM-AC run will represent the optimal commitment decisions for meeting forecasted load. Therefore these resources will comprise the eligible pool of resources for unit commitment in the DA IFM and DA RUC. This approach avoids sub-optimal commitment decisions that can arise by committing resources in two stages, first in the DA IFM based on load schedules and bids, then again in the DA RUC based on the ISO load forecast.

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<sup>9</sup> This ensures that unit schedules will only be decreased to resolve congestion on the non-competitive paths rather than being substituted by lower mitigated incremental bids to meet system load.

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43. RMR and LMPM requirements are determined by comparing the resource schedules derived from the Pre-IFM-RMPM-CC and the Pre-IFM-RMPM-AC runs. Specifically:
- For RMR units, the Pre-IFM-RMPM-AC schedule will be the RMR dispatch level if this schedule is greater than its Pre-IFM-RMPM-CC schedule. In this case the unit's market bid above the dispatch level will be retained unless mitigated by System AMP. If the unit's Pre-IFM-RMPM-AC schedule is not greater than its Pre-IFM-RMPM-CC schedule, the unit's original market bid will be retained in its entirety unless mitigated by System AMP.
  - For non-RMR units, the unit will be subject to LMPM if its Pre-IFM-RMPM-AC schedule is greater than its Pre-IFM-RMPM-CC schedule. In such cases, only the portion of the unit's bid curve that is associated with the additional dispatch amount from the Pre-IFM-RMPM-AC run will be subject to local market power mitigation.<sup>10</sup>

This approach provides effective local market power mitigation while minimizing the amount of mitigation in two ways. First, only the portion of the bid curve dispatched to resolve non-competitive congestion is subject to local market power bid mitigation. Second, the bid curve will not be mitigated to a price below its highest accepted bid in the Pre-IFM-RMPM-CC run.

44. The final IFM run is based on submitted demand schedules and bids. It uses RMR cost-based bid prices for the RMR dispatch levels determined as described above, and the appropriate combination of market and mitigated bids as determined in the previous steps. All bids – mitigated and unmitigated, RMR and non-RMR – will be eligible to set the LMPs. Since the Final IFM is based on submitted demand schedules and bids and not on the ISO's load forecast, the market clearing quantities are apt to be less than the forecasted amounts. In such cases, the un-dispatched bids from the Final IFM run will be available for the ISO to commit additional capacity in the Residual Unit Commitment (RUC) procedure to meet forecasted load. Thus the bids used in RUC will be market-based or mitigated (cost-based) as determined above.
45. For the HA IFM, the following procedure will be done after bids have been submitted to the HA market. First, the ISO will determine any incremental RMR requirements based on SCUC and dispatcher knowledge, insert the RMR Price for these incremental quantities, and notify RMR owners about this incremental dispatch through an ex-post dispatch notice. Second, the ISO will perform the HA Pre-IFM-RMPM run based on forecast demand to determine the need for any additional global and local market power mitigation as described in the DA IFM steps above, with final Day Ahead schedules having priority over Hour Ahead incremental schedules (see the discussion in the section on Treatment of Self Schedules). Finally, the ISO will perform the Final IFM run based on submitted demand bids and schedules, utilizing any additional bid mitigation and incremental RMR dispatch resulting from the previous steps.
46. During the real-time pre-dispatch process,<sup>11</sup> the following procedure will be done prior to the start of the operating hour. First, the ISO will determine any incremental RMR requirements based on SCUC and dispatcher knowledge, insert the RMR Price for these incremental

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<sup>10</sup> The ISO may need to mitigate an small additional portion of the bid curve (e.g., 1 or 2 MW) to ensure that the unmitigated portion of the bid curve does not effect the final determination of LMPs. That is, LMPs should be determined not on forecasted load but from the cost of meeting an additional MW of load bid or scheduled at each location.

<sup>11</sup> The real-time pre-dispatch process is performed in the hour prior to the operating hour to enable the ISO to give dispatch instructions to resources whose operating constraints prevent them from being dispatched on a 5-minute basis during the operating hour.

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quantities, and notify RMR owners through an ex post dispatch notice. Second, the ISO will perform the RT pre-dispatch run based on forecast demand to determine the need for any additional global and local market power mitigation as described in the DA and HA IFM RMPM steps above. Any additional bid mitigation and RMR dispatch levels resulting from the previous steps are then incorporated into the RT market.

**2.2.7 Ancillary Services Markets**

47. The ISO proposes to incorporate Ancillary Service (A/S) procurement into the Day Ahead and Hour Ahead IFM. The ISO will procure four services in these markets: Regulation Up, Regulation Down, Spinning Reserve ("Spin") and Non-spinning Reserve ("Non-spin"). The ISO will allow SCs the option of self providing A/S to meet their obligations or relying on the ISO's procurement of A/S. The ISO may procure only a portion of its expected requirement in the Day Ahead IFM and procure the remainder in the Hour Ahead IFM. By the close of the Hour Ahead IFM, however, the ISO will have procured its entire expected A/S requirements for that operating hour.
48. A/S may be provided by Participating Loads that meet ISO requirements. Current ISO and WECC standards limit this to provision of Non-spinning Reserve.
49. A/S resources will be selected in the IFM using an integrated approach that co-optimizes energy and A/S procurement to minimize total bid costs based on each resource's energy and capacity bids. Resources that do not submit capacity bids for A/S will not be considered for A/S procurement. The Ancillary Service Marginal Price (ASMP) determined in the IFM for each service will implicitly include the opportunity cost associated with providing the A/S instead of being scheduled for energy in the same market, if such opportunity cost exists. If the IFM commits a resource to provide energy or A/S the resource will be eligible for start-up and minimum-load cost compensation.
50. The A/S requirements will be determined by the ISO prior to the IFM optimization, based on the ISO's load forecast, estimated firm net interchange, and anticipated Real Time system conditions. Depending on network constraints and congestion, A/S requirements may be determined for major sub-areas of the ISO control area, which may result in different A/S clearing prices for each sub-area for each service. Although suppliers of A/S will be paid the appropriate area-specific ASMP, loads will be charged one system price per service. Within some constrained areas of the grid the ISO may need to limit the amount of A/S procured so that resources within those areas can be utilized for energy to the extent needed. Higher-quality services can substitute for lower-quality services in A/S procurement when such substitution reduces total procurement bid cost. For example spinning reserve service can be procured to meet a portion of the requirement for non-spin.
51. A/S may be provided via imports, up to limits pre-specified by the ISO. Imported A/S will require transmission allocation in the IFM, which means that A/S capacity and energy will compete for transmission capacity across inter-control area interfaces. If A/S imports contribute to congestion an inter-tie, the supplier of the A/S import will be charged the applicable congestion usage charge. A scheduled A/S import does not create a counter-flow for an energy export schedule since the A/S import has no associated energy flow schedule.
52. The current "Contingency Only" flag for Operating Reserves (Spinning and Non-spinning Reserve) will be retained, allowing Operating Reserve providers the ability to opt into the real-time imbalance energy dispatch or stay out of the imbalance energy dispatch to be reserved for contingency situations only.

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53. The ISO will procure additional operating reserves (Spin and Non-spin) in Real Time if needed to maintain required reserves when A/S capacity procured or self-provided in the forward markets is dispatched in Real Time for energy or is unavailable due to outages. Real Time A/S procurement will be conducted as part of the intra-hour short-term resource commitment procedure every 15 minutes, and will be performed using dynamic co-optimization of energy and A/S. Resources selected in this process will receive notice via the ISO's Automated Dispatch System (ADS). There will not be a market clearing price for real-time A/S procured, nor will capacity bids be considered. Rather, a resource designated to provide A/S in Real Time will receive its opportunity cost, determined as the positive difference between the real-time clearing price and the resource's energy bid price over the range of capacity selected to provide the additional A/S capacity. If the ISO commits an off-line resource for real-time A/S, that resource will be eligible for recovery of its applicable start-up and minimum load costs.

**2.2.8 Ramp Rates**

54. The scheduling and dispatch software will support the following three ramp rates:

- **Operational ramp rate function** – up to 10 ramp rates over the entire operating capacity of the resource. (This feature will be implemented with Phase 1B.) The operational ramp rate function will be submitted with the preferred schedule and will be validated to be between a minimum and a maximum operational ramp rate function registered in the Master File. The operational ramp rate function will be used to limit hourly schedule changes in the forward markets and to limit the amount of Supplemental Energy that can be dispatched in Real Time. The ramp rate function is fixed throughout the day and can only be changed (by notifying the ISO via SLIC) when something occurs to alter the ramping capability of the unit.
- **Operating Reserve ramp rate** – for Spinning and Non-Spinning Reserve – shall be a single ramp rate value, distinct from the Operational ramp rate function. The Operating Reserve ramp rate will be submitted with the preferred schedule and will be validated to be between a minimum and maximum Operating Reserve ramp rate in the Master File. The Operating Reserve ramp rate will be used in procuring Operating Reserves in the forward markets and in Real Time. This ramp rate is fixed throughout the day and can only be changed (by notifying the ISO via SLIC) when something occurs to alter the Operating Reserve ramping capability of the unit.
- **Regulation ramp rate** – shall be a single ramp rate value. The regulating ramp rate will be submitted with the preferred schedule and will be validated to be between a minimum and a maximum regulating ramp rate registered in the Master File. The regulating ramp rate will be used to procure Regulation Up and Down in the forward markets. Resources must bid the same ramp rate for Regulation Up and Regulation Down for the same operating period. The ramp rate is fixed throughout the day and can only be changed (by notifying the ISO via SLIC) when something occurs to alter the regulating capability of the unit.

55. In Phase 1B the ISO proposes also create a “No-Pay” charge to account for differences between the amount of capacity awarded in the forward markets and the amount actually available for real-time dispatch. This feature will be maintained when the IFM is implemented. The Operating Reserve ramp rate will be used to procure spin and non-spin in the IFM. The Regulation ramp rate will be used to procure Regulation in the IFM and to dispatch the unit in Real Time if the unit is on regulation (i.e., dispatched by AGC), but if the resource is not on regulation the Operational ramp rate function will be used for real-time



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dispatch. In Real Time a 10-minute available capacity quantity will be calculated based on the relevant real-time dispatch ramp rate. This quantity will be compared with the amount of capacity that was awarded A/S and any differences will be charged a weighted average rate calculated from the ASMP and the A/S capacity procured in the forward markets, thus creating a “No-Pay” mechanism for unavailable capacity.

56. Phase 1B will also deal with differences between a unit’s RMR contract ramp rate and its Operational ramp rate. This feature will also carry over to the IFM. A resource will have a one-time opportunity to modify its RMR contract to declare that its RMR contract ramp rate is effectively equal to its bid-in Operational ramp rate. This enables the ISO to use the same ramp rate regardless of when the RMR unit is dispatched. If the resource opts not to make such a declaration, then the RMR contract ramp rate will be used as the Operational ramp rate.

**2.2.9 Unit Commitment in the IFM**

57. The IFM will include a unit commitment optimization whereby the ISO will commit resources to meet load that self schedules or bids and clears the energy market. The unit commitment algorithm (SCUC) used in the Day Ahead IFM and RUC will utilize a multi-day time horizon in order to take realistic account of units with start-up times that are longer than one day and other operating constraints such as minimum run times and minimum down times. Similarly, the SCUS used in the Hour Ahead IFM and RUC will utilize a multi-hour time horizon. The ISO is continuing to assess the optimal lengths of these time horizons considering the trade-off between realistic treatment of resource operating constraints and the uncertainties associated with longer forecasts. As described earlier, the only resources considered for commitment in the IFM will be those resources committed in the Pre-IFM-RMPM runs. The IFM unit commitment will make use of the three-part bids described in the section on “Bid Structure and Validation.”
58. If the IFM commits a resource that was not otherwise self committed, that resource will be eligible for recovery of its start-up and minimum load costs in accordance with the following terms. The unit-specific Commitment Period for which the ISO would guarantee recovery of start-up and minimum load (SU/ML) costs (net of market revenues) is defined as the period during which absent commitment by the IFM (or RUC) the unit would have been in OFF or shut down status based on its submitted self schedules for energy or A/S, considering its start-up time, minimum run time, and minimum down time. For multi-day unit commitment runs, the SU/ML cost recovery guarantee beyond the first day of the commitment cycle applies only to those resources that must begin their start up process during the first day of the IFM (RUC) commitment cycle in order to be able to comply with the energy or A/S schedule assigned to them in the IFM (RUC), considering their current commitment status (based on any available telemetry or their schedule from previous unit commitment results), their start-up time, minimum run time, and minimum down time.

**2.2.10 Load Aggregation and Trading Hubs**

59. The ISO proposes to create various specific aggregations of nodes for the purpose of load scheduling, bidding and settlement and as trading hubs. From a transactions perspective, participants can utilize these aggregations to simplify their daily bidding, scheduling and trading activities. The ISO will assign load distribution factors (LDFs) to each defined aggregation to distribute schedules and bids to individual nodes for the purpose of running the IFM and establishing final schedules. Thus the IFM will adjust schedules at the nodal level for clearing the energy market and managing congestion and to determine nodal

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prices. The ISO will assign appropriate weights to each aggregation for the purpose of calculating aggregate prices as weighted averages of the nodal prices comprising each aggregation. A later section of this document describes load aggregation in more detail.

60. LDFs have two dimensions, geographical and temporal. Geographically, the LDFs will be defined for different types of aggregations such as trading hubs and load aggregation zones. For each geographical category, the ISO will define and maintain a library of LDFs that are applicable to different time periods, i.e., for different day types (business day, Saturday, and Sunday/Holiday) and for different hours within each day type (hourly, peak, and off-peak). These LDFs will be established and revised based on the ISO's State Estimator.<sup>12</sup> Each time the State Estimator completes a successful execution, the corresponding set of LDFs (for the relevant day-type, period, and hour of the day) will be updated based on the most recent State Estimator results using exponential smoothing (i.e., computing a weighted average of the most recent LDFs and the existing LDFs, with a pre-specified weighting factor).
61. There will initially be three load aggregation zones for the purpose of load scheduling, bidding and settlement, defined as the transmission service areas of the three California investor owned utilities (IOUs), i.e., PG&E, SCE and SDG&E. Virtually all loads within the ISO control area that are not served under ETCs will be scheduled, bid and settled at the level of the load aggregation zone in which they are located.<sup>13</sup> This includes municipal utility and direct access load as well as load receiving retail service from the IOUs' distribution companies. Load served under ETCs will not be included in these aggregations for the purpose of calculating LDFs or aggregate prices.
62. Trading hubs may be defined as needed and appropriate to support commercial trading. Initially the ISO proposes to designate the existing congestion zones as trading hubs (i.e., NP15, ZP26 and SP15), to provide continuity for current bilateral energy contracts that utilize these zones as points of delivery. The ISO will also create trading hubs corresponding to the three load aggregation zones (PG&E, SCE and SDG&E) to facilitate trades with load serving entities. An important characteristic of trading hubs is that their definitions do not change over time and their LDFs and weighted average prices are always based on the total quantity of load that is served at each node of the hub. Thus, in contrast to the load aggregations mentioned above, trading hub LDFs and prices will include load served under ETCs if such load is within the ISO control area.

### **2.2.11 Existing Transmission Contracts**

63. Although the ISO would prefer that all Existing Transmission Contracts (ETCs) be converted to CRRs, the ISO recognizes that full conversion of all ETCs will not likely occur until some time after the MD02 design is implemented. MD02 therefore provides a method to continue to honor ETC rights. Under the MD02 proposal, ETC rights holders will continue to submit

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<sup>12</sup> The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, including information on the current status of transmission lines, generators, transformers and other equipment, bus load distribution factors, and a representation of the electric network, which collectively provide a complete description of system conditions, including conditions at busses for which real-time information is unavailable. The State Estimator will run every five minutes, and will provide the megawatt output of generators and the loads at busses in the ISO Control Area, transmission line losses, and actual flows or loadings on constrained transmission facilities.

<sup>13</sup> Load reduction in response to an ISO real-time dispatch instruction will be paid the appropriate locational price. For further detail on the limited exemptions from load aggregation see Section 2.6 on "Demand Scheduling, Bidding and Settlement."

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balanced schedules to the ISO markets, which will be given scheduling priority over other users of the ISO controlled grid in the Day Ahead and Hour Ahead markets, in accordance with the provisions described in the section on "Treatment of Self Schedules," to the extent such schedules conform to the rights holders' contractual rights. In particular, in the Day Ahead market valid ETC self schedules will be the last to be adjusted in the event that non-economic adjustments are required to relieve congestion. In contrast to today, however, the ISO will not reserve any transmission capacity for ETCs beyond the capacity used by their Day Ahead schedules. In the Hour Ahead market, ETC schedule changes will be given priority over all other Hour Ahead schedule changes and will be accepted as fully as possible without modifying final Day Ahead schedules. Any portion of Hour Ahead ETC schedule changes that cannot be accepted in the Hour Ahead market will be accepted as Real Time schedule changes. In addition, ETC rights holders will be able to submit, and the ISO will accept, further schedule changes after the Hour Ahead market closes in accordance with the ETC rights. In Real Time the ISO will re-dispatch non-ETC resources relative to their final Hour Ahead schedules as needed to accommodate valid real-time ETC schedule changes.

64. The PTOs with which ETC rights holders have contracted will be responsible for certifying to the ISO that submitted ETC schedules and schedule changes are consistent with the contractual rights of the rights holder. Such certification may be subject to periodic review by the ISO or audit by an independent third party, but will not be validated on a daily basis by the ISO.
65. The load side of ETC schedules will be scheduled and settled at specific network nodes or, if applicable, the interfaces of a metered subsystem (in contrast to the load side of non-ETC schedules, which will be scheduled and settled at the appropriate Load Aggregation Zone).
66. Except for the exclusion of ETCs from the load aggregation provisions, all ETC schedules and real-time deviations will be treated the same as those of other ISO grid users in the settlement process and thus will be assessed all applicable charges, such as congestion charges and real-time uninstructed deviation penalties. The ISO recognizes that schedules and energy flows covered by ETC rights are generally exempt under their contract terms from some charges, such as congestion and transmission losses, that arise from use of the transmission system. The ISO therefore proposes to provide special Scheduling Coordinator IDs (SCIDs) for PTOs to use for scheduling and settlement in conjunction with their ETCs, to facilitate allocation of cost responsibilities between PTOs and ETC rights holders. This may be accomplished, for example, by the PTO and the ETC rights holder submitting an inter-SC trade from the ETC holder to the PTO at the point where power enters the ISO controlled grid, and another inter-SC trade from the PTO to the ETC holder where the power is withdrawn to serve the ETC load.

### **2.2.12 Determination of Losses**

67. The ISO proposes to incorporate the cost of losses into the locational marginal prices (LMPs) produced by the IFM optimization. This will require the use of a SCUC that models transmission losses in the IFM, as is done by the New York ISO. From this SCUC each nodal LMP can be decomposed into three components, a reference energy price (i.e., system energy absent transmission constraints and losses), the cost of marginal losses and the cost of congestion.

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68. With losses so internalized, it will not be possible for SCs to self-provide losses explicitly,<sup>14</sup> though this can be accomplished by another means in the forward markets. Specifically, the SC can estimate the amount of losses it will be responsible for and self-schedule additional supply to cover the estimated losses, using the payment for the excess supply to offset the cost of losses. Depending on the location where the SC self provides to cover losses, this payment may be more or less than their share of the cost of losses procured optimally and priced through LMP. While this method may not be precise in each hour, over time the amount of losses should become predictable by the SC with reasonable accuracy.

**2.2.13 Day Ahead Market Time Line**

69. The ISO intends to retain the current time of 10 A.M. for closing the Day Ahead market to SC submissions. The proposed Day Ahead market process will eliminate today's "revised preferred" iteration with SCs. The IFM will produce a final Day Ahead schedule before performing the Day Ahead Residual Unit Commitment (RUC) procedure. The ISO proposes not to publish the Day Ahead schedule, however, until after the running of RUC, at which time the ISO will publish the final schedule resulting from the IFM as well as any additional unit commitment or capacity reservations resulting from RUC.

70. Following the Day Ahead IFM the ISO will perform the Day Ahead RUC procedure,<sup>15</sup> which is described fully in a later section. All unused bids submitted to the IFM by Must Offer and non-Must Offer resources will automatically be rolled over to the RUC, so there will be no need for an additional bid submission prior to the running of RUC. The ISO will complete both the Day Ahead IFM and the Day Ahead RUC procedure before 1 P.M. and will publish the results of both at approximately 1 P.M.

71. As explained in the section on Market Power Mitigation and Local Reliability, RMR dispatch will be integrated into the IFM process and there will no longer be a need for the ISO to issue RMR pre-dispatch instructions prior to the closing of the Day Ahead IFM at 10 A.M., so long as the provisions of this proposal integrating RMR into the IFM and RUC are approved.

**2.3 Congestion Revenue Rights (CRRs)**

72. Adopting the LMP paradigm requires replacing the ISO's existing Firm Transmission Rights (FTRs), which are defined in terms of specific transmission paths, with a "source-to-sink" (often referred to as "point-to-point"<sup>16</sup>) congestion hedging instrument.<sup>17</sup> The ISO will adopt the term "Congestion Revenue Rights" (CRRs) to distinguish this redesigned source-to-sink congestion hedging instrument from today's path-specific FTRs. A source-to-sink CRR specifies as its "source" a single network node or set of nodes (such as a trading hub) at

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<sup>14</sup> SCs will be able to self-provide losses explicitly in Phases 1B and 2. The issues discussed in this section apply only to Phase 3.

<sup>15</sup> Subsequent to the IFM, which is based on SCs' preferred schedules and bids, the ISO will perform the RUC procedure for reliability purposes to commit the additional resources it expects to need to meet the next day's load forecast.

<sup>16</sup> The term "source-to-sink" is preferable to "point-to-point" and will be used throughout this document. The term "source-to-sink" is more compatible with the notion that source and sink may be a specified set of network nodes, whereas "point-to-point" tends to be understood as requiring that source and sink must each be single network nodes.

<sup>17</sup> Because CRRs are a congestion hedging instrument, the revenue entitlement to CRR holders will not include the cost of transmission losses.

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which power is injected or delivered to the transmission grid, and as its sink a single network node or set of nodes (such as a load aggregation zone or a trading hub) at which power is withdrawn from the transmission grid.<sup>18</sup>

73. In conjunction with the source-to-sink CRR model, the ISO must perform a simultaneous feasibility test (SFT) to determine the quantities of CRRs that can be released via the allocation and auction processes described below.
74. The proposed CRR design will be primarily an “obligations” instrument, in contrast to today’s “options” FTRs.<sup>19</sup> With CRR obligations a CRR holder is liable for congestion charges when congestion is in the opposite direction of their CRRs. As long as the CRR holder schedules in accordance with their CRRs, however, their payment for counter-flow scheduling offsets the liability of their CRR obligation. One exception to the obligations model is that ETC rights holders who convert their rights will have a choice of receiving either CRR options or CRR obligations.
75. The ISO proposes to allocate CRR obligations to all loads within the ISO control area that are not served under ETCs,<sup>20</sup> including loads such as those of the State Water Project that are not formally served as retail consumers by a load-serving entity (LSE). The underlying principle is that loads that pay the Transmission Access Charge (TAC) are entitled to an allocation of CRRs. In general such CRRs will be allocated to LSEs on behalf of the loads they serve, but the CRRs will “follow the load” if the consumer switches to a different LSE. This makes it unnecessary to create new CRRs when a new LSE enters the market and acquires existing customers of another LSE. Any remaining transmission capacity available for CRRs beyond what is needed to cover the load will be offered in an ISO-operated auction, with revenues from the sale of any non-allocated CRRs going to reduce the Transmission Revenue Requirement (TRR) of the relevant Participating Transmission Owner (PTO).
76. The ISO intends to allocate quantities of CRRs that are adequate to fully cover the load in 99.5 percent of the operating hours of the year, provided these quantities are simultaneously feasible as determined by the process described below. The CRR study that is currently in progress will provide an early indication of whether it will be feasible to allocate CRRs at this level.
77. In the ISO’s May 1 and June 17, 2002 MD02 filings the ISO had proposed to allocate CRRs to LSEs “net of local generation.” Subsequently the ISO recognized that a workable definition of “local generation” would be extremely difficult to implement in a nodal LMP market design and therefore decided to drop the netting provision. The ISO now proposes to allocate CRRs in the full (i.e., gross) amount needed to serve load fully in at least 99.5 percent of the operating hours of the year (unless a lower level is requested by the LSE in question for whatever reason).

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<sup>18</sup> The ISO will explore the possibility of offering path-specific or “flowgate” rights, in addition to source-to-sink CRRs, if there is a need for this type of instrument in the future.

<sup>19</sup> As noted below, the ISO will offer CRR options to the holders of ETC rights who convert their rights to CRRs. The ISO will also explore the possibility of making CRR options more generally available in the future as more experience is gained by other ISOs that are currently introducing combined obligations and options CRR models.

<sup>20</sup> When ETC holders convert their rights to CRRs, the load that was served under the ETC receives protection through the CRRs allocated in the conversion process, as discussed later in this section.

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78. As noted elsewhere in this proposal, all load<sup>21</sup> not served under ETCs will be scheduled, bid and settled at a level of aggregation corresponding to the transmission service areas of the three investor-owned utilities in California (PG&E, SCE and SDG&E). This provision greatly simplifies the congestion hedging problem and the allocation of CRRs. The result is that loads need only be concerned about congestion charges between the supply node and the appropriate load aggregation zone. Therefore the CRRs allocated to loads will feature one of the three load aggregation zones as the sink.
79. The ISO recognizes that full conversion of all ETCs will likely take longer to achieve than the time frame for initial implementation of MD02, and therefore this proposal presumes that the ISO will have to accommodate some quantity of non-converted ETCs for the foreseeable future. The earlier section describes how ETCs will be fully honored in the scheduling process. In addition, with regard to the release of CRRs, the ISO will perform a simultaneous feasibility test using all non-converted ETC rights to determine how much transmission capacity will be available for release as CRRs. This is described in more detail below.
80. The congestion component of the nodal energy prices produced by the integrated forward market (IFM) will be the reference for congestion charges. Thus the congestion charge for injecting 1 MWh at node A and withdrawing 1 MWh at node B will be the congestion component of the energy price at node B minus the congestion component of the energy price at node A. This is the price difference to be hedged by CRRs. In other words, CRRs do not protect the holder from nodal price differences due to transmission losses.
81. Settlement of all payments and charges related to CRRs will be based on Day Ahead IFM prices. CRRs will not be applicable to the Hour Ahead and Real Time markets.
82. The ISO will also offer Network Service CRRs (NS-CRRs) as a convenience for participants in the allocation and scheduling processes. In the allocation process, NS-CRRs enable load-serving entities that can serve their load from multiple supply nodes to obtain a bundle of CRRs that provide an optimal congestion hedge at least cost. To obtain a NS-CRR a participant will specify a set of injection nodes or inter-ties and assign nodal quantity bids or priorities to indicate the preferred distribution of rights over these nodes and acceptable adjustments in case the preferred distribution is not feasible. The CRR allocation procedure will provide the preferred distribution if possible, or can optimize the distribution to provide the set of rights most valuable to the participant. Once the NS-CRR is issued the distribution factors for the injection nodes will be fixed. Holders of NS-CRRs may unbundle them into single-injection node CRRs for secondary trading, consistent with the distribution factors defining the NS-CRR. Of course, as a result of such trading the distribution factors of the NS-CRR will be revised to reflect the remaining rights.
83. CRRs (including NS-CRRs) will provide physical scheduling priority for the demand sink in the Day Ahead IFM, in accordance with the principles described in the section on "Treatment of Self Schedules." To use the CRR scheduling priority the SC will attach CRRs to the demand side of a balanced preferred schedule between the appropriate source and sink, in the same direction as the CRRs, and submit this schedule without decremental bids on the demand side. Scheduling priority will apply to the Day Ahead market only.
84. In any given hour the amount of congestion revenues may not exactly equal the settlement of all CRRs. This is because CRRs are released based on a single snapshot of system conditions, and these conditions in fact may vary from hour to hour. In order to maintain the hedge as far as possible, the ISO will create a balancing account that accumulates the

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<sup>21</sup> With some limited exceptions which are discussed in the section on "Demand Scheduling, Bidding and Settlement."

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excess revenues generated in hours when total congestion charges exceed required CRR payments, and then to distribute these revenues to keep CRR holders whole in hours when congestion charges are inadequate. Funds in the balancing account will be disbursed at the end of each month to CRR holders who were not fully compensated during the month. Any residual monthly surplus or shortfall will be addressed at the end of the year. At the end of each year the balancing account will be zeroed out, with any surplus going to PTOs. If the balancing account turns out to be short at the end of the year, it indicates that CRR holders have not been fully compensated for their CRR entitlement over the 12-month period.

85. The ISO proposes to release CRRs initially based on two different term lengths: annual (for the current year and the following year) and monthly (before each month). The transmission network capacity that will be available for annual CRRs for any given operating year will be limited to 75 percent of the capacity that remains after accommodating simultaneously feasible non-converted ETCs as power transfer options. In the first annual CRR auction, all 75 percent will be auctioned for the first year of the CRR term, but only half (37.5%) will be released for the second year. For the subsequent annual CRR auctions, the incremental amount of CRRs auctioned for the first year of the CRR term will be the difference between the relevant 75 percent level at that time, and the amount auctioned in the preceding CRR auction for that year. The volume of CRRs released for the following year will be based on the 37.5% of the relevant transmission capacity. This enables participants to obtain CRRs that are valid for a period of two years following the allocation procedure. The remaining network capacity will be available for monthly CRRs and will be based on expected system conditions for the coming month, taking into account seasonal factors and planned outages.
86. Following the allocation the ISO will run a CRR auction to allocate any transmission capacity that remains after loads and converted ETC holders received their shares (allocation to ETC conversions is discussed below). Entities that receive an initial allocation of CRRs will be able to participate in this auction as buyers or sellers, and the auction revenues generated by the sale of these allocated CRRs will be paid to the selling entities. CRR auction revenues generated by the sale of any capacity not previously allocated to loads and converted ETC holders will be paid to PTOs to be applied towards the Transmission Revenue Requirement (TRR).
87. Based on the design features described above, the ISO proposes to perform the following sequence of steps in offering CRRs. The same sequence of steps will be followed for both the annual and monthly CRR offerings. Step (1) estimate the amount of transmission capacity that will be utilized by ETCs that do not convert to CRRs; (2) provide CRRs to ETCs that convert to CRRs and to new PTOs who join the ISO; (3) allocate CRRs to loads (LSEs); and (4) perform an auction for market participants who wish to bid for any remaining CRRs available. At each step the ISO will run a simultaneous feasibility assessment on the relevant set of desired rights, after fixing the allocation of rights that resulted from the previous step.
- Step 1. Estimation of transmission capacity needed to honor non-converted ETCs. The purpose of this step is solely to estimate the amount of transmission capacity that must be withheld from the CRR allocation and auction processes, to enable the ISO to release CRR quantities that neither over- nor under-subscribe the transmission system in light of the need to honor ETC rights in the daily scheduling processes. The capacity calculation described here will not affect the ISO's ability to fulfill its intention of honoring ETC rights fully in daily scheduling and real-time operation.

The ISO proposes to estimate transmission capacity for non-converted ETCs based on their historic reservation patterns on their contract paths and specific sources and sinks.

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This will require that ETC rights holders provide the ISO with descriptions of their normal use of the grid under their ETC rights, with specific quantities of generation and load at each location.<sup>22</sup> The ISO will then perform a simultaneous feasibility assessment of the patterns of all non-converted ETCs to determine the collective impact on the grid of the entire set of ETCs. In the event that all ETC reservation patterns are not simultaneously feasible the algorithm will have to make curtailments based on global ETC priorities, as agreed upon by the relevant PTOs, to achieve simultaneous feasibility. Keep in mind that such curtailment is only to determine CRR release and will not affect the ISO's ability to honor ETCs fully in scheduling and real-time operation.

In performing the simultaneous feasibility for this step the ISO will assume that all ETCs are options rather than obligations, consistent with the way ETC rights are specified. Because ETCs are options, the effect of this step is effectively to reduce the transfer capacity of the grid by removing the estimated ETC capacity completely from the CRR allocation and auction process. With obligations-type rights, in contrast, the impact of the rights on transfer capacity could be offset by counter-flow schedules, so that allocated rights have no absolute effect on the availability of capacity for use by others.

- Step 2. Allocation of CRRs to converted ETCs and new PTOs. With the capacity for non-converted ETCs removed from further transmission capacity availability calculations, the ISO would address the set of ETCs that had converted to CRRs and the CRRs offered to new PTOs and assess their simultaneous feasibility. As in the previous step, these entities would have to provide their normal grid use patterns. The ISO would prefer to provide CRR obligations to these entities. This would be optimal from a market design point of view because then all CRRs would be of the same type. The ISO recognizes, however, that offering CRR options may increase the incentives for ETC holders to convert and proposes to offer ETC holders a choice of CRR options or obligations if they convert. While this does create the complication of having two types of CRRs initially, the quantity of converted ETCs should be relatively small and have little impact on the availability of CRRs for other transmission users.
- Step 3. Allocation of CRR obligations to loads. For this step the LSEs or other eligible loads would have to provide the grid usage patterns they normally rely upon to meet their needs, and again the ISO would run an obligations-type simultaneous feasibility. The ETC capacity set aside in Step 1 and the CRR options allocated in Step 2 would not be available in this run. CRR obligations allocated to converted ETCs would be included as fixed injections and withdrawals, however, since the obligations model accounts for counter-flows in the simultaneous feasibility test. In the event that not everything is simultaneously feasible the ISO would curtail load or LSE CRR requests first, and preserve converted ETC CRR obligations as far as possible, to provide converted ETCs a higher degree of certainty of receiving their desired CRRs as a benefit for converting.
- Step 4. Allocation of remaining CRRs through a CRR auction. Unlike the previous three steps where no bids were involved, in this step market participants will bid to buy the CRRs they wish to obtain, and entities allocated CRRs in the previous steps will be able to offer to sell some of their CRR obligations if they wish to do so. This time the ISO would run a bid-based obligations-type simultaneous feasibility, protecting those allocated CRRs that were not offered for sale, executing trades between buyers and sellers and awarding the remaining available transmission capacity to maximize the auction proceeds. Parties selling CRRs that were previously allocated to them would

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<sup>22</sup> Seasonal variations in ETC usage can be addressed by performing this assessment on a monthly or seasonal basis, rather than just once for the entire year.



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receive the auction proceeds for the CRRs they sold. The remaining auction revenues would be allocated to the PTOs in proportion to their TRRs.

88. CRRs may be used in conjunction with A/S schedules. In an IFM where energy and Ancillary Services (A/S) are procured simultaneously, generating capacity is allocated optimally between energy and A/S awards. The ISO will procure A/S for specific areas of the grid subject to constraints and congestion, to minimize the potential impact of congestion within the ISO-controlled grid on the deliverability of energy from A/S capacity. All selected bidders within an A/S area will be paid the ASMP for the area and hence there will be no need for a CRR hedge. For A/S imports across inter-ties, the forward market will allocate transmission capacity between energy and A/S capacity based on submitted energy and A/S bids. Under this approach, the A/S import will pay the usage charge for using the inter-tie, and CRRs can provide a financial hedge against this cost.
89. No changes are proposed to the ISO's current approach for handling trades in the CRR secondary market. Currently the ISO does not conduct a secondary market, but does require both parties to any secondary trade of CRRs to register their trades in the ISO's Secondary Registration System (SRS). For secondary trading, CRRs may be unbundled into any specific hours of the day, days of the week, seasons, etc., that the parties determine to be desirable, and network-service CRRs (NS-CRRs) may be unbundled into their separate injection nodes consistent with the distribution factors defining the CRR.
90. When new transmission capacity is added or removed, the ISO will review the impact of the change on the system network to determine the appropriate amount of new capacity to be released in subsequent CRR allocations and auctions. When a new transmission line or an upgrade to an existing line becomes operational, it will alter flows throughout the network and may require modifications to the pattern of CRRs that can be released.
91. In the case of a market-based transmission upgrade, the parties responsible for creating the new transmission capacity will be entitled to receive CRRs reflecting the added capacity once the upgrade is in service, as long as they are in fact bearing the cost of the upgrade and not recovering their investment through an access-charge-based revenue requirement. Market participants who receive a regulated rate of return on investment for building or upgrading transmission will not receive CRRs for the added capacity.

## 2.4 Residual Unit Commitment

92. The ISO will perform a Day Ahead (and Hour Ahead) Residual Unit Commitment (RUC) process immediately after the Day Ahead or Hour Ahead IFM has run and has established feasible final Day Ahead or Hour Ahead schedules. Both the Day Ahead and the Hour Ahead IFM clear based only on the bids and self schedules that SCs have submitted, without regard to the ISO's load forecast. In the event that these markets close significantly below the ISO's load forecast and do not commit adequate resources to meet that forecast, the RUC provides a reliability backstop to enable the ISO to commit additional supply resources if needed to meet the system load forecast and reserve requirements in compliance with NERC and WECC reliability criteria, as well as local reliability needs. Final schedules will be published to the market following the completion of the IFM and RUC.
93. The ISO needs both a Day Ahead and an Hour Ahead RUC because resources having different start-up times will be issued commitment instructions in each. That is, the Day Ahead RUC will issue commitment notices only to resources requiring day ahead or longer notice, whereas the Hour Ahead RUC will issue commitment notices to resources requiring

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only a few hours or less notice. As noted earlier, in order to account realistically for resource operating constraints in the commitment process the SCUS used in the Day Ahead RUC (Hour Ahead RUC) will utilize a multi-day (multi-hour) time horizon.

94. All resources subject to Must Offer Obligations – either under the existing Must Offer provisions imposed in the Commission’s mitigation orders, or under a future resource adequacy requirement – will be required to participate in the RUC procedure.<sup>23</sup>
95. At the time the ISO first implements Phase 2 of MD02 (the IFM), there may not yet be a fully effective resource adequacy program. Therefore the RUC design proposed here has certain provisions that will apply at the start-up of the IFM but will be adapted once there is an effective resource adequacy requirement. The main provisions of the initial design which the ISO expects to adapt later are: (1) initially all supply bids submitted to the Day Ahead or Hour Ahead IFM that are not selected in that market – from Must Offer and non-Must Offer resources – will roll over to the Day Ahead or Hour Ahead RUC process. Once the resource adequacy requirement is operative, RUC may be limited to the pool of resources identified as fulfilling the adequacy requirements of a responsible entity (i.e., only the Must Offer resources); and (2) the ISO’s proposed availability payment for capacity committed in RUC will be eliminated once the resource adequacy requirement is operative, since resources that participate in RUC would be Must Offer resources and thus would earn capacity payments under the resource adequacy program that will compensate them for meeting their Must Offer participation and availability requirements.
96. The capacity procurement target for the Day Ahead RUC will be the next day’s hourly load forecast plus reserve requirements, minus (1) the final Day Ahead schedule of energy plus A/S capacity; (2) a forecast of expected incremental Hour Ahead schedule changes; (3) a forecast of additional supplemental energy bids expected on the operating day. The ISO will fine-tune this estimation procedure in practice to minimize over and under procurement. Also, to the extent that metered subsystems within the ISO control area under-schedule in the Day Ahead market but have designated adequate resources under their control to meet their own load and reserve needs, the RUC will not procure capacity to cover their share of the next day’s forecast, nor will the ISO allocate a share of RUC commitment costs to these entities.
97. Although RUC will procure a combination of energy and unloaded capacity (including demand response) to meet 100 percent of the capacity procurement target, the energy procurement (from System Resources and the minimum load of RUC-committed resources) will be limited if possible to a maximum of 95 percent of the next day’s hourly demand forecast. The remaining five percent or more will be covered by the unloaded capacity of resources that are scheduled for energy in the Day Ahead IFM (excluding any capacity scheduled to provide A/S) plus the unloaded capacity of any additional units committed by the RUC process. This five percent margin is intended to allow for load forecast error, to minimize the risk of over-procurement of energy by the RUC, and to avoid creating an incentive for loads to under-schedule in the Day Ahead market and rely on RUC. In the event of a conflict between the objectives of 100 percent capacity coverage and no more than 95 percent energy coverage, the 100 percent capacity objective takes precedence.

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<sup>23</sup> As discussed in the previous section, Must Offer resources that have verifiable use limitations will not be expected to perform beyond their use limitations, except possibly when emergency conditions make it necessary for the ISO to call upon them. Therefore, such resources will be considered in the RUC process only as their use limitations allow.

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98. The RUC process will procure minimum load energy and unloaded capacity from internal resources. The RUC process will procure only energy from import suppliers, provided adequate capacity is available on the inter-ties to accommodate this energy after the running of the IFM. Minimum load energy from internal resources and energy procured from inter-ties in the Day Ahead RUC will have scheduling priority over incremental Hour Ahead energy schedules in the Hour Ahead IFM.
99. Resources that did not participate in the Day Ahead IFM will not be eligible to participate in Day Ahead RUC. They can still participate in Hour Ahead IFM and Hour Ahead RUC.
100. RUC will optimize its selection of resources by minimizing the total bid cost of procuring the resources, including the bid-based availability payment, and dispatching them for Real Time energy to fully meet the Real Time load forecast. The three-part bids submitted in the Day Ahead IFM will be used in this RUC process, including each resource's start-up and minimum load bids and its incremental energy bid curve as submitted to the IFM. Technical constraints like minimum load energy and minimum run time must be the actual physical constraints of the resource, not market-based bid constraints. Import bids, however, may not be resource specific and therefore may not have cost-based start-up and minimum load bids. The IFM and RUC optimization will consider only the energy bids submitted by these suppliers. Similarly, RUC will not consider start-up and minimum load bids for resources scheduled in the Day Ahead IFM that have additional uncommitted capacity, since these resources were self-committed.
101. Resources committed by the ISO in the Day Ahead RUC will be eligible for recovery of start-up and minimum load costs,<sup>24</sup> net of market profits during its commitment period and subject to restrictions on self scheduling noted below and contingent on the RUC-procured capacity being fully available for and responding to ISO dispatch instructions. Market profits for the purpose of this SU/ML cost recovery provision may derive from energy payments, A/S capacity payments and the RUC availability payment discussed below. The length of the commitment period will depend on certain operating characteristics of the unit, including start-up time, minimum run time, minimum down time, etc. Resources that self schedule energy or self provide A/S in the Day Ahead IFM will be viewed as self-committed and will not be compensated by the ISO for SU/ML costs. The resource eligible for SU/ML cost recovery in the Day Ahead RUC may lose its eligibility during all or part of its commitment period if it self schedules energy or A/S in the Hour Ahead IFM or engages in uninstructed deviations (beyond a tolerance band<sup>25</sup>) in the Real Time market. Similarly, a resource eligible for SU/ML cost recovery in the Hour Ahead RUC may lose its eligibility during all or part of its commitment period if it engages in uninstructed deviations (beyond a tolerance band) in the Real Time market.
102. In the interim period until there is a functioning resource adequacy program, unloaded capacity will receive a per-MW availability payment for each MW of RUC-procured capacity that is not awarded A/S or dispatched for energy in Hour Ahead or Real Time. Resources

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<sup>24</sup> Resources not self-committed in the Day Ahead (Hour Ahead) IFM may also be committed by the ISO in the IFM's unit commitment procedure, and these resources will also be eligible for recovery of start-up and minimum load costs. The cost allocation in this instance is not the same as the RUC cost allocation, however. Any uplift required to compensate ISO-committed resources in the IFM will be recovered from all loads scheduled in that market in excess of supply per SC portfolio, whereas uplift charges due to RUC commitment will be recovered primarily from real-time loads that were not scheduled in the Day Ahead (Hour Ahead) IFM. See below for additional details.

<sup>25</sup> The tolerance bands used for this purpose will be the same as those being established in Phase 1B for assessing uninstructed deviation penalties.

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may submit a bid for RUC availability (in \$/MW per hour) as a component of their IFM bids, up to a cap of \$100 per MW per hour. The availability payment will be rescinded for each MW of RUC capacity that is scheduled or dispatched for energy or awarded A/S capacity in a subsequent market. The resource's entire availability payment for a given hour will be rescinded if the resource engages in uninstructed deviations beyond the ISO's allowable tolerance band or is not available to respond to an ISO dispatch instruction. The availability payment will be paid as-bid to resources selected in RUC, and the cost of the payment will be included with other RUC commitment costs identified above and recovered through a RUC uplift charge described below. The RUC process will take into account this availability bid along with the start-up, minimum load and incremental energy bids in the optimization.

103. The unloaded capacity committed in RUC may be scheduled for energy or A/S capacity in the Hour Ahead IFM or dispatched in real-time based on the resource's submitted energy bids, subject to activity rules discussed elsewhere in this document. The incremental energy bid curves associated with such capacity will be submitted to the Hour Ahead IFM, and any additional energy not cleared against load bids in the Hour Ahead IFM will be available for real-time dispatch. The incremental energy bids associated with capacity selected in RUC cannot be increased in price once they are selected, but may be decreased prior to Hour Ahead or Real Time if the resource wishes to increase its probability of Real Time dispatch.
104. Any energy procured in the Day Ahead RUC – i.e., the minimum load energy of internal resources committed by RUC as well as energy procured from import suppliers – will be submitted to the Hour Ahead market as a price taker (i.e., a self schedule) and, if cleared against load bids, will earn the appropriate locational market clearing prices. Any of this energy not cleared in the Hour Ahead market, as well as any additional energy procured in the HA RUC process, will be submitted to Real Time as a price taker and again may earn market clearing prices. Such resources will receive additional payment through the RUC uplift charge in the event that their revenues from market clearing prices do not cover their energy bid prices.
105. Units committed in RUC will be selected based on system reliability on a zonal basis in Phase 2 and on a nodal or local area basis in Phase 3. For the foreseeable future, local reliability needs that are met today using Reliability Must Run (RMR) resources will continue to be met by RMR. In areas where RMR resources either have not been designated or are not available, however, the RUC process could be used to address local reliability needs as well as system needs.
106. Cost causation principles will apply in allocating RUC costs. Costs associated with the RUC process will be borne first by SCs whose metered load is not fully scheduled in the Day Ahead market (excluding Metered Subsystem load that is covered by its own resources and therefore does not cause any RUC procurement, as noted elsewhere). The ISO will calculate a per MWh RUC charge by dividing total RUC procurement costs by the amount of RUC capacity or energy procured, and will allocate this per MWh charge to each MWh of metered load in excess of final Day Ahead schedules. Thus the ISO will allocate Day Ahead RUC charges first to metered load in excess of final Day Ahead schedules. These charges will be in addition to the cost of energy to serve such load in the Hour Ahead or real-time markets. Any excess of RUC costs not recovered in this manner (i.e., if the total MWh of under-scheduled load is less than the total MWh of RUC procurement) will be allocated to all metered demand plus exports. Similarly, the costs associated with Hour Ahead RUC will be allocated first to metered load in excess of final Hour Ahead schedules.

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107. The ISO will allow Metered Subsystems to follow their own load, without incurring RUC costs, provided they establish resources in advance, schedule all load and exports in the Day Ahead market, and meet a bandwidth requirement.
108. Following each hourly run of the Hour Ahead IFM the ISO will perform the Hour Ahead RUC procedure. This procedure will allow the ISO to assess whether the total energy scheduled and capacity committed in the final Hour Ahead schedule and the Day Ahead RUC procedure will be adequate to meet the expected energy and reserve needs of the coming operating hour. If there appears to be a shortfall, the ISO can commit additional resources that may require advance notice of an hour or more to be available for Real Time operation. Alternatively, in the event that the updated load forecast declines or a large increase in scheduled supply appears in the Hour Ahead so that the capacity procured in Day Ahead RUC now appears to be excessive, the ISO will be able to cancel start-ups that were previously instructed but are not yet completed. The ISO will pay a pro rata share of the start-up payment for resources that have partially completed their start-up cycle in response to an ISO instruction before they were de-committed by the ISO.

**2.5 Hour Ahead and Real Time Markets**

109. In the earlier MD02 filings the ISO proposed to revise the Hour Ahead time line. Rather than closing the Hour Ahead market to submissions at two hours prior to the beginning of the operating hour as is done today (referred to as T-120 minutes), and ISO proposed to close the market at T-60, and to simultaneously close bid submissions to the real-time or supplemental energy market. Based on new input from stakeholders and reassessment of the feasibility of running all elements of the IFM between T-60 and Real Time, the ISO has decided to withdraw the proposal to move the Hour Ahead market up to T-60 and to close the real-time market at the same time. Instead, the ISO now proposes to close the Hour Ahead IFM at T-120, to publish final Hour Ahead schedules at T-90, and to close the real-time market at T-60, thus allowing a 30-minute re-bid period between final Hour Ahead schedules and the close of Real Time bid submissions.
110. As noted earlier, Security Constrained Economic Dispatch (SCED) in Real Time is being implemented as the primary design element of MD02 Phase 1B in October 2003. The initial implementation will feature the ISO's current three-zone network model, however, so with the introduction of the full network model (FNM) into the integrated forward market (IFM) in MD02 Phase 3, the FNM will also be installed for use with real-time SCED. Additional details on Phase 1B and real-time SCED are contained in the ISO's various filings on this subject [cite] and are not discussed further in this document.
111. The ISO still anticipates performing a real-time pre-dispatch at approximately T-45 to enable the ISO to give real-time dispatch instructions to supply resources that are needed for the coming operating hour but cannot change operating levels in response to intra-hour dispatch instructions. This is consistent with the ISO's earlier MD02 filings. Pre-dispatch quantities will be calculated taking into account the expected real-time imbalance. Imports that are pre-dispatched for the entire hour will be guaranteed their bid price but cannot set the five-minute MCP. To the extent that the simple average of the five-minute MCPs for the hour falls below their bid price the difference will be paid to suppliers and charged to the market as an uplift. Internal hourly generation that is pre-dispatched is eligible to set the MCP so long as there is a system need for the energy. If system conditions change and the hourly internal generation is no longer needed, the resource will still be guaranteed at least its bid price but will no longer be eligible to set the MCP.

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112. Some internal generation may be able to change operating levels in response to intra-hour dispatch instructions but may have other operating constraints that render it “lumpy” (e.g., minimum operating level, minimum run time). The general principle is that such resources will always be guaranteed at least their bid price when they respond to ISO dispatch instructions, but will only be eligible to set the five-minute MCP when their energy is needed by the system. For example, suppose in interval three it is economic to dispatch a resource that has a 50 MW P<sub>min</sub> for 30 MW. The ISO has to take all 50 MW of its first block in order to dispatch this resource and meet load, otherwise we would have to dispatch another more expensive resource. In this case the lumpy resource will be allowed to set the interval three MCP. Now suppose in interval four it is still economic to serve load with this resource, but had the resource been flexible to dispatch anywhere between 0 and 50 MW it would have been dispatched at 20 MW. In this case the resource will still be eligible to set the interval four MCP. Now suppose in interval five the resource is no longer needed at all to economically serve load, but still must be operate at minimum load due to a minimum run-time constraint. At this point the resource is no longer eligible to set the MCP. Regardless of whether the resource sets the price in any interval, it is eligible for an uplift payment to ensure that it recovers its Minimum Load cost in case the MCP is insufficient.
113. The design of the ISO’s proposed sequence of three settlement markets is intended to allow market participants to manage their costs and risks in an economically efficient manner while limiting their ability to engage in detrimental gaming behavior. There are a number of design elements that are relevant to this issue: (1) the Must Offer Obligation to which a subset of resources are subject and which requires them to offer all available capacity into the ISO’s markets; this provision prevents such resources from exercising physical withholding; (2) the requirement to submit a single energy bid curve to be used for the energy and A/S markets, congestion adjustment, and RUC process; and (3) limitations on how bidders may change their bids between successive markets, which we refer to as “re-bidding activity rules.”
114. The underlying principles of the proposed activity rules are:
- Bid prices that are accepted in one market time frame are contractual commitments. Therefore accepted incremental bid prices associated with RUC and A/S capacity cannot be increased, and decremental bid prices associated with scheduled energy cannot be decreased in a subsequent market time frame. This applies to final Day Ahead or Hour Ahead energy schedules, A/S capacity awards and the energy bids associated with that capacity, and the energy bids associated with RUC commitments. The ISO will, however, allow the incremental energy bid prices associated with unloaded A/S or RUC capacity to be lowered in a subsequent market if the supplier wishes to increase the likelihood of dispatch, and will allow decremental bid prices associated with scheduled energy to be increased in a subsequent market.
  - Energy or capacity that is offered in one market time frame but not accepted by a buyer (i.e., a demand bid for energy, or the ISO in the case of A/S and RUC) is no longer a binding commitment on the part of the seller and may be offered in a subsequent market time frame at a higher price, or not offered at all in the ISO’s markets (subject, of course, to any applicable Must Offer obligation). In this case the only restrictions are due to the structure of the energy bid curve (i.e., monotonicity, and at most 20 segments.)
115. For the sake of clarity the following proposed rules are written in terms of Hour Ahead energy bid submission after final Day Ahead schedules have been established. The same rules will apply to real-time energy bid submission after final Hour Ahead schedules have

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been established, with certain obvious modifications to cover all the capacity and energy that was procured in both the Day Ahead and Hour Ahead IFM and RUC procedure.

- (1) If the Hour Ahead energy bids overlap only with the portion of the capacity that is covered by the resource's Day Ahead energy bids (in contrast to self-schedules that were submitted without bids), the bid price of the decremental portion of the bid relative to the final Day Ahead energy schedule cannot be less than the Day Ahead bid price for the same energy.
- (2) If the Hour Ahead energy bids overlap with the portion of the capacity that is self-scheduled (without bids) in the Day Ahead market, the bid price shall not be lower than the bid floor which is currently  $-\$30/\text{MWh}$ .
- (3) Generating units committed in the Day Ahead market (including A/S self-provision or award) or in the Day Ahead RUC may not de-commit without reporting an outage to the ISO.

116. The ISO had originally proposed to enforce the re-bidding activity rules by allocating A/S awards to the right-most portion of a unit's energy bid curve, which would effectively limit the re-bid opportunity of unselected capacity to the level of the energy bids associated with A/S awards. It has since been determined that this approach would create an incentive for suppliers to bid the right most portion of their Day Ahead energy bid curve at an extremely high level to maximize their flexibility for re-bidding in subsequent markets. Rather than create such an incentive, the ISO now proposes to enforce the re-bidding activity rules by allocating awarded Day Ahead A/S capacity to the portion of the Day Ahead energy bid curve that immediately proceeds the portion allocated to Day Ahead RUC. Under this approach, the portion of the energy bid curve associated with Day Ahead RUC and A/S cannot be re-bid at prices higher than the Day Ahead bid prices. However, any remaining capacity of the resource can be re-bid in subsequent markets at any level, subject to AMP and maintaining the monotone structure of the curve.

117. The incremental energy bids that were used to establish a resource's final Day Ahead and Hour Ahead schedules will be available to the ISO to use in Real Time for decremental adjustments (i.e., below the resource's final Hour Ahead schedules) to economically clear the imbalance energy market and mitigate real-time congestion.

## **2.6 Demand Scheduling, Bidding and Settlement**

118. In order to realize the benefits of the LMP paradigm without exposing consumers to risks of high energy prices in constrained locations of the grid, the ISO proposes to (1) settle supply resources (generation and real-time dispatched demand reduction) at nodal prices, and (2) settle loads at wholesale prices that are aggregated to three large areas defined by the transmission service territories of the California investor-owned utilities (IOUs), i.e., PG&E, SCE and SDG&E. As noted earlier the ISO also proposes to allocate Congestion Revenue Rights (CRRs) to loads to hedge any remaining congestion cost risk due to the locations of their supply sources.

119. This aggregation scheme will apply to all loads in the ISO control area, including municipal utility loads and direct access loads as well as loads served by the IOUs. The only exceptions to this aggregation scheme will be as follows:

- Loads served under non-converted ETCs will be excluded from the aggregation scheme. Such loads will schedule and settle at locations appropriate to their specific ETC rights.

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- Demand reduction by Participating Loads will be settled at the appropriate locational price.
  - Entities that can operate as either loads or generators (e.g., cogeneration and pumped storage hydro facilities) will be treated as generators and will schedule, bid and settle at the appropriate locational level.
120. Although SCs will submit load schedules and bids at the level of the default aggregations, the ISO's IFM will perform congestion management and energy trading at the nodal level. Prior to running the IFM, load schedules and bids will be disaggregated to the nodal level using load distribution factors (LDFs) that are derived from the ISO's real-time state estimator. This will ensure that the spatial distribution of loads that are input to the IFM reflect the actual spatial distribution of loads expected in Real Time. The IFM will then make adjustments to generation and load at the nodal level to clear congestion and execute energy trades. Subsequent to the IFM adjustments, the nodal load schedules will be re-aggregated to create final load schedules for each SC at the default aggregation level, which will be settled at aggregate prices that are load-weighted averages of the constituent nodal prices.<sup>26</sup>
121. The present proposal differs from the ISO's original (May 1, 2002) Comprehensive Design Proposal in two significant ways: (1) the three default load aggregation areas identified above represent a much higher level of aggregation than the ISO's original proposal; and (2) the present aggregation proposal is mandatory for loads (except as noted above), whereas the original proposal offered loads the option of selecting nodal scheduling, bidding and settlement or a custom aggregation of nodes if they have appropriate settlement-quality metering or qualify as a metered subsystem.
122. The ISO's MD02 proposal recognizes that demand response is a vital ingredient in the design of a well-functioning electricity market. Although the implementation of retail demand programs is ultimately the responsibility of load-serving entities (LSEs) and state agencies, the MD02 design supports these programs by establishing needed market infrastructure and incentives,<sup>27</sup> including transparent, Day Ahead hourly prices and improved opportunities for load to participate in ISO markets as resources that augment and compete with supply resources. These opportunities, which require loads or aggregated load entities to execute a Participating Load Agreement to establish sound mechanisms for data and settlement flows between the ISO to SCs, include:
- The Day Ahead energy market, allowing a commitment to load reduction at a price established with enough time to schedule daily production at an industrial facility (or similar planning for other loads). Viewed another way, a Participating Load can express, through its Day Ahead energy bid, its willingness to reduce its energy use below its normal level if the energy price goes above a specified value, or to use additional energy if the price is low. Currently, loads can consume below their Day Ahead schedules and be paid as uninstructed deviations at real-time prices, but the benefits of doing this are uncertain because loads cannot in general predict real-time prices accurately. Thus the

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<sup>26</sup> Since ETC schedules will be excluded from the proposed aggregation scheme, the distribution factors and price calculations described here will net out ETC loads within the ISO control area.

<sup>27</sup> For example, the end-use load can only get a benefit from the wholesale price if it is allowed by the CPUC or the local regulatory authority. An end-use load under a retail rate can only benefit from curtailing when the prices go up, or from using more energy when the prices go down, if the retail tariffs established by the local regulatory authority provide an option for hourly interval pricing, which allows the load-serving entity to pass through some type of charge or credit in addition to the bundled customer's retail rate.



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new Day Ahead market creates a new opportunity for consumers to respond at a known price.

- The Day Ahead Residual Unit Commitment (RUC) process, allowing a Participating Load to commit to a real-time dispatchable reduction at a pre-specified price per MWh and be assured, in return for this commitment, of recovery of associated stand-by costs through the ISO's RUC start-up and minimum-load cost compensation provisions.<sup>28</sup> (Any load intending to use a back-up generator must obtain and provide to the ISO written approval from their local Air Quality Management District.)
  - The Hour Ahead energy market, allowing price responsiveness to be offered when permitted by daily conditions.
  - The Real Time energy market, allowing ISO-dispatched demand response to earn the Real Time locational price (rather than the aggregated price) and to be pre-dispatched in competition with other inflexible resources like inter-ties and combustion turbines (CTs), with assurance of recovering start-up costs and at least its bid price for energy, and of operating for a minimum run time.
  - Ability to set the Real Time price, for Participating Loads that have appropriate real-time telemetry.
  - Continued ability to participate in A/S markets, thus receiving a capacity price for providing non-spinning reserve.
  - Continuation of relaxed telemetry requirements for Non-spinning Reserve (one-minute updates from the participating load to the SC's server, as opposed to four-second updates from generators), waiver of telemetry requirements for supplemental energy, and eligibility to set the real-time ex post LMP. Only interval metering and ability to receive and follow dispatch instructions are necessary to supply supplemental energy. For participation in DA and HA energy markets, only the separate reporting of energy metering is needed, at the level at which the price response is offered, using metering requirements established by the Local Regulatory Authority.
123. Participating Loads that wish to engage in the above opportunities will be required to demonstrate their effective dispatch capability. The minimum size for Real Time dispatch would be the amount allowed by the ISO's Automated Dispatch System (ADS), i.e., 0.1 MW. Individual loads under 1 MW may be aggregated as dispatchable load. Also, larger loads at the same bus may be aggregated, and justifications for aggregation of loads of 1 MW or more that are within local areas but on different buses (e.g., pumping loads within the same watershed or water delivery system) will be considered on a case-by-case basis. Because Real Time energy requirements will be locational, bids that are eligible for Real Time dispatch (ancillary service and supplemental energy) would need to be bid at the nodal level (or appropriate aggregation of nodes).
124. One significant change introduced by MD02 Phase 2 (the IFM) is the use of voluntary three-part bids, incorporating start-up and minimum-load costs in addition to the energy bid curve. A bid for demand response does not need to use all these bid components, but may do so at the option of the bidder. Participating Loads may incur actual costs, similar to start-up and minimum-load costs of generators, although these would be difficult for the ISO to verify. Therefore the three-part bids submitted by Participating Loads will be market-based and will not require verification of actual costs. Thus the bids submitted by loads will compete with generation for commitment through the RUC process, and ultimately for

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<sup>28</sup> An example is provided below to illustrate how this may work.

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dispatch in the forward and real-time energy markets. This will ensure the most comparable treatment between load and generation resources that can feasibly be provided.

## 2.7 Local Market Power Mitigation

125. In its June 17, 2002 MD02 filing the ISO proposed a PJM approach to local market power mitigation (LMPM). Under this approach, if the ISO must dispatch a generating unit as a direct result of congestion within the ISO controlled grid that cannot be managed competitively in either the forward or Real Time markets, the ISO will dispatch the resource and determine LMPs based on the resource's Default Energy Bid (defined below). From a policy standpoint, this approach remains the ISO's preferred approach for addressing local market power. However, given FERC's previous rulings on LMPM provisions for California and other ISOs, it is not clear that FERC would approve this approach for California. Recent rulings from FERC indicate a preference towards an AMP mechanism (conduct and impact tests) to address local market power. Given the regulatory uncertainty on precisely what type of LMPM the ISO will ultimately be granted, the ISO believes it is prudent to have the flexibility in the market software to accommodate both the preferred PJM-like approach and an AMP mechanism.
126. Default Energy Bids for most thermal resources will be cost-based bids, equal to the incremental cost of the unit plus 10 percent.<sup>29</sup> For resources not having an applicable cost-based bid, the ISO will calculate mitigated bids based on the following methodology, listed in order of preference:
- Mean of LMP prices at unit's relevant location for the lowest priced quartile of prices during unmitigated periods that the unit was dispatched or scheduled over the previous 90 days.<sup>30</sup> This price will be calculated separately for peak and off-peak, and adjusted for fuel prices as applicable.
  - A level determined in consultation with the market participant prior to the application of the mitigation.
  - Determined by the ISO based on the ISO's estimated cost of the generating unit.
  - An appropriate average of competitive bids from one or more similar units.
127. Both the PJM and AMP approaches will require a determination of when to mitigate and which resources will be subject to local market power mitigation. The first step for identifying the resources that will be subject to LMPM is to determine the transmission paths where congestion can be resolved competitively. Initially only the ISO's existing inter-zonal branch groups (Path 15, Path 26 and the inter-ties, plus local constraints out of local generation

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<sup>29</sup> In its June 17, 2002 MD02 Filing, the ISO did not propose a 10% variable cost adder but does so now to be more consistent with PJM and the ISO's recently filed Amendment 50. The ISO's Amendment 50 proposed a +/- 10% cost adder depending on whether the unit was being dispatched up or down. Under Phase 3, the ISO is only proposing a positive 10% adder because local market power problems will be predominately in the incremental direction. Moreover, having a different cost curve that depends on the direction of dispatch would not be a viable approach under a nodal market structure as it could lead to anomalous results, such as a unit being repeatedly dispatched up and down due to toggling between to different bid curves.

<sup>30</sup> The lowest quartile was used to reflect the fact that the variable cost of most dispatched resources is infra-marginal (i.e. below the market clearing price). The lowest quartile approach is consistent with the Reference Price methodology used in the ISO's current AMP.

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pockets) will be declared competitive. All other transmission paths will be considered non-competitive but will be evaluated periodically based on a forward-looking competitive assessment.

128. The periodic competitive assessment will apply a Residual Supply Index (RSI) test<sup>31</sup> for all effective resources that can relieve the congestion on a particular transmission path. If there are three or more suppliers that own effective resources and the RSI is greater than 1.2 for more than 95% of the time within a specified period (e.g., summer on-peak, winter off-peak), the transmission path will be declared competitive for the period.
129. This forward assessment will be updated periodically to reflect changing market conditions, and will be reevaluated after actual market operation in each season. If the actual market outcome is not consistent with a competitive outcome, a transmission path's competitive status will be revoked and re-designated as non-competitive.
130. Having identified the non-competitive transmission paths, the next step is to determine which resources will be subject to LMPM in each hour. This will be done by performing two pre-processing runs of the IFM software, which are also used for determining RMR dispatch levels as described in Section 2.2.6.
131. Having identified the criteria for determining the resources and bid quantities that are subject to LMPM, the next step is to determine whether or not to apply LMPM. Under the preferred PJM approach, the identified resources and bid quantities subject to LMPM would be automatically mitigated as described earlier. The alternative and less preferred AMP LMPM approach is more involved as it requires a test of whether any of the submitted bids violated a conduct threshold (i.e., a conduct test) and if so, a determination of whether these bids have a material impact on locational prices (i.e., a market impact test).
132. LMPM AMP Conduct Test. Under the LMPM AMP approach, market bids associated with any positive incremental dispatches in the second Pre-IFM run would first be subject to a conduct test. LMPM bid reference levels for the conduct test would be based on each unit's Default Energy Bids (i.e. cost-based bids) rather than the average of accepted bids as is used in System AMP, and LMPM conduct thresholds would be the lower of \$10/MWh or 20% above the unit's LMPM bid reference level. Default Energy Bids are used as reference levels in the LMPM AMP because using bid-based reference levels (as is used in System AMP) would create a strong incentive for generator owners that are frequently subject to LMPM to strategically bid up their reference levels. While this incentive exists to some extent for units subject to System AMP, it is less of a concern because of the limited frequency that suppliers are impacted by System AMP mitigation.
133. LMPM AMP Market Impact Test. Any positive incremental dispatch in the second Pre-IFM run that exceeded the conduct threshold would trigger a market impact test. The market impact test would involve re-running the Pre-IFM with all transmission constraints enforced based on mitigated bids. If this mitigated run reduces nodal prices by more than the lower of \$10/MWh or 20% then the mitigated run will stand.

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<sup>31</sup> The RSI is equal to total supply minus the supply of the single largest supplier divided by total demand [(Total Supply – Largest Supplier)/Total Demand]. An RSI value less than 1.0 indicates demand cannot be met absent the largest supplier (i.e. the largest supplier is pivotal and therefore has market power). Historical studies performed by the ISO's Department of Market Analysis have indicated a strong correlation between price-cost markups and RSI values and that there are significant price-cost markups when RSI values are below 1.2.

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Substantially lower bid conduct and market impact thresholds are proposed for LMPM AMP because local market power can be exercised much more frequently than system-wide market power. The conduct and market impact thresholds proposed here may be modified over time as the ISO gains experience under LMP and may eventually transition to threshold levels that are customized for particular aggregations of nodes (i.e. pre-defined load pockets) based on the frequency of congestion.<sup>32</sup>

134. The mitigated bid curves derived from the processes described above, whether through the preferred direct mitigation of the PJM approach or through an AMP approach, will be passed on to the final IFM, which is based on submitted demand schedules and bids, to determine final schedules and prices. Bids mitigated under LMPM will be eligible to set the LMP in the final IFM.
135. Since the final IFM is based on submitted demand schedules and bids, the market clearing quantities are apt to be less than the forecasted amounts. In such cases, the undispached bids from the Final IFM run will be available for the ISO to commit additional capacity to meet forecasted load. This additional capacity commitment will occur through the residual unit commitment (RUC) process. The bids used in RUC will be market-based or mitigated/cost-based as determined above.
136. The LMPM procedures described above would apply in the Day Ahead, Hour Ahead, and real-time markets to reflect changes in system conditions, particularly load forecasts. However, the LMPM procedures would only apply to incremental dispatches. The DEC game, which exists under the ISO's current zonal market design, arises in situations where resources over-schedule in violation of intra-zonal constraints in the forward market and then submit large negative bids to decrement their schedules in real-time. This game is mainly possible because the ISO does not enforce the full network model in the forward market and therefore allows infeasible schedules to be accepted. Imposing the full network model in the forward markets will largely eliminate the DEC game. However, there will remain a small potential for suppliers to play the DEC game when there is a transmission de-rate between the Day Ahead and Hour Ahead market or between the Hour Ahead market and real-time. During such periods, suppliers could submit new decremental bids at very high negative prices. To address this residual concern, the ISO has developed re-bidding activity rules that prohibit suppliers from lowering their accepted energy bids in subsequent markets. The ISO believes the combination of imposing the full network model in the forward market and the proposed re-bidding activity rule will adequately mitigate the DEC game.
137. The ISO anticipates it will continue to enter into annual RMR contracts for units that are critical for local reliability until such time that there is an alternative annual capacity market (e.g. resource adequacy requirements) that addresses local areas needs. RMR contracts are a means to ensure that generating units required to meet local reliability criteria remain economically viable and are not able to exercise local market power. Thus, RMR contracts will work in concert with the local market power bid mitigation provisions to protect against the exercise of local market power. It is important to note that not all units capable of exercising local market power will have RMR contracts. RMR contracts are provided to particular units that are needed to meet specific "Applicable Reliability Criteria" (ARC), which ensure that sufficient capacity is available to meet a narrowly defined set of generation and transmission contingencies. As a consequence, there are units that are not needed to meet

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<sup>32</sup> One option for future consideration is the NYISO approach of setting locational thresholds at levels that would result in no more than a 2% increase in average annual prices at each location. However, this approach would not be possible in the first year of Phase 3 operation because the ISO would lack the historical price and congestion data to compute such thresholds.

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the ARC and therefore are not designated as RMR units but will nonetheless be capable of exercising local market power under particular system conditions.

138. Under the Phase 3 market design, it will also be necessary to change the way RMR dispatches are scheduled and bid into the market (the proposed changes are described in Section 2.2.6). The current ISO Tariff provisions pertaining to the bidding and scheduling requirements of RMR units operating under Condition 1 RMR contracts<sup>33</sup> were created in the context of a zonal forward energy market, i.e., the California Power Exchange (PX). Under the current provisions the ISO issues RMR pre-dispatch instructions to Condition 1 RMR units prior to the Day Ahead market, and unit owners can comply with these instructions by electing either a “contract path” or “market path.” When the PX existed, a unit owner who elected the contract path would be required to bid the RMR pre-dispatch quantity into the PX Day Ahead Market at \$0/MWh (i.e., as a price-taker) and would receive the variable cost payment specified in the RMR contract.<sup>34</sup> If the unit owner elected the market path, however, it would forfeit the RMR variable cost payment and would instead rely on the market to recover its variable cost. A unit owner that elected the market path was free to bid the RMR pre-dispatch quantity into the PX Day Ahead market at any price, or even not to bid the pre-dispatched quantity into the Day Ahead market at all. Regardless of whether the unit owner elected the contract or market path, any amount of Day Ahead RMR dispatch that was not scheduled in the ISO Day Ahead market was required to bid into the Day Of PX market as a \$0/MWh price taker bid or be scheduled as a bilateral contract in the ISO’s Hour Ahead market.
139. Since the PX market was a zonal market, there was no opportunity for the RMR unit owner choosing the market path to exercise local market power through bidding excessively high. If the unit owner bid excessively high into the PX Day Ahead market, its energy would likely not be selected and it would then be required to bid into the subsequent PX Day Of market as a price taker or submit an Hour Ahead bilateral schedule that equaled the RMR dispatch quantity. The contract and market path options remain under the ISO’s current market design despite the demise of the PX market. Currently, RMR unit owners electing the market path for a Day Ahead RMR pre-dispatch instruction must self-schedule that quantity in the ISO’s Day Ahead or Hour Ahead market.
140. If the ISO were to retain the same “market path” provisions for RMR dispatches under the Phase 3 market design, unit owners that elect the market path for Day Ahead RMR pre-dispatches would be allowed to bid the pre-dispatched quantity into the ISO’s Day Ahead nodal energy market. Since the ISO’s Day Ahead energy market would enforce the full network model, providing such an option for RMR unit owners would enable them to exercise local market power by submitting high bids for their RMR dispatch quantities. While it may be possible to mitigate this local market power through the application of the LMPM provisions, the ISO believes this would defeat the very purpose of the RMR contracts, which is to ensure that units critical for local reliability are not able to exercise local market power.
141. Therefore, the ISO proposes to eliminate the contract and market path options for RMR units as specified in Section 2.2.12.2 of the ISO Tariff and provide a single option that has

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<sup>33</sup> There are two types of RMR contracts, Condition 1 and Condition 2, the main distinction being that under Condition 1 contracts, the RMR contract covers only a portion of the unit’s annual fixed costs and the unit is allowed to participate in the market so that it can recover its remaining annual fixed costs. Under Condition 2 contracts, the RMR contract covers the entire annual fixed cost, the unit is precluded from participating in the market and is under complete dispatch control by the ISO.

<sup>34</sup> The RMR owner would also receive a payment from the market for the value of the energy produced by the RMR unit, but would then credit back this payment under the terms of the RMR Contract.

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desired elements of both. Specifically, the ISO will determine RMR dispatch quantities using the Day Ahead, Hour Ahead, and Real Time procedures described in Section 2.2.6 of this document. The ISO will assign bids to these RMR dispatch quantities equal to the lower of the unit's submitted market bid (if applicable) and the RMR contract variable cost. These assigned bids will be available for dispatch and eligible to set the LMPs in the subsequent market. All Condition 1 units will be able to keep market revenues in excess of the RMR contract variable cost. There will be no option for different payments (i.e., contract versus market path). This approach strikes a compromise in that Condition 1 unit owners are restricted from having bids above their RMR contract variable cost applied to their RMR dispatch, but are able to earn and keep market revenues above their contract variable cost. Under this approach, excess revenues for Condition 2 units are credited toward their fixed cost compensation as is done currently.