California Independent System Operator

Market Design 2002 Project

Comprehensive Market Design Proposal

April 29, 2002

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1 EXECUTIVE SUMMARY

1.1 The Market Design 2002 Project

1.1.1 Introduction

ISO Management initiated the Market Design 2002 (MD02) project to (1) take a comprehensive view of the changes needed in the structure of California's electricity markets, with a focus on those markets operated by the ISO in performance of its core functions, and (2) develop an integrated program of proposed market design changes that will address current problems in a systematic fashion and create a framework for a sustainable, workably competitive electric industry that benefits all California consumers and is compatible with the rest of the western region.

In proposing to develop such a program of changes, ISO Management recognizes that the root causes of California's electricity crisis extend beyond the design and performance of the ISO, and that a complete solution to prevent a similar crisis in the future will require more than design changes to the ISO. In particular, actions are needed by policy makers and other agencies to expand generating capacity, encourage forward contracting and demand-side programs by those entities that serve end-use customers, and promote construction of needed transmission upgrades. At the same time, ISO Management is convinced that a comprehensive program of changes to the ISO markets is appropriate and necessary – even urgent – at this time because:

- the rules and incentives embodied in the design of the ISO's markets have a major impact on the incentives of other parties to invest and to enter into contractual relationships that will protect California consumers and support a sustainable electric industry;
- there are well-known deficiencies in ISO market design that need to be redesigned to enable the ISO to better perform its core function of providing reliable, non-discriminatory transmission service; and
- the existing market mitigation measures established by FERC's June 19, 2001 Order and related decisions are set to expire on September 30, 2002,[1] at which time the ISO's rules and procedures must be crafted to do everything possible, within the scope of the ISO's function, to maintain market stability and reliable grid operation. As noted above, however, continued stability after September 30 will require additional actions by policy makers and agencies outside the ISO. The present proposal identifies some specific areas where such action is needed, particularly to ensure adequate supply capacity to serve California consumers at reasonable prices.

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[1] On December 19, 2001 FERC issued an Order denying the ISO's motion for rehearing of the September 30 expiration date. The ISO had argued that the date was arbitrary and that to remove mitigation without a determination that the ISO markets were no longer subject to manipulation through the exercise of market power was an abrogation of FERC's obligation under the Federal Power Act to ensure just and reasonable rates. With FERC's denial of the ISO's motion, the only remaining recourse to seek reversal of this decision is through judicial review, which ISO Management initiated on February 14 in a petition submitted to the U.S. Court of Appeals for the Ninth Circuit.

1.1.2 Project Deliverables

Accordingly, the MD02 project is organized to produce four major deliverables:

- a Comprehensive Design Proposal that identifies the problems to be addressed and describes the entire program of market changes proposed to address those problems;
- a package of "October 1st Elements" that contain those elements of the Comprehensive Design that must be in place by September 30, 2002, when the existing FERC market mitigation measures are set to expire;
- an initial FERC Tariff Filing that contains the changes to the ISO Tariff needed to implement the October 1st Elements, to be filed simultaneously with the Comprehensive Design Proposal in narrative form (i.e., the present document); and
- a second FERC Tariff Filing that contains the changes to the ISO Tariff needed to implement the Comprehensive Design Proposal.

1.1.3 Time Frame

ISO Management currently envisions the entire MD02 process from design to implementation to be completed according to the following time line:

May 1	File Tariff language for October 1st Elements and narrative version of Comprehensive Design Proposal at FERC
June 15	File Tariff language for Comprehensive Design Proposal at FERC
October 1	Implement October 1st Elements to provide market mitigation when existing FERC mitigation provisions expire
Spring 2003	Implement Comprehensive Design built upon existing three-zone network model
Fall 2003	Complete the implementation of the Comprehensive Design when Full Network Model becomes operational.

1.1.4 FERC's Standard Market Design Proceeding

In 2001 the Federal Energy Regulatory Commission (FERC) initiated a Standard Market Design (SMD) proceeding, to specify the elements of an optimal electricity market structure for ISOs and RTOs. Towards this end FERC issued a Staff Paper in December 2001, a Commission Working Paper on March 15, 2002, and a Commission Options Paper on April 10, 2002. These documents have thus far provided a strong sense of FERC's preferences with regard to market design and identified areas where additional work and consideration are required. The ISO has participated in FERC-sponsored activities related to the SMD and has paid close attention to FERC's guidance and preferences in developing the Comprehensive Design Proposal and the October 1st Elements. Although the SMD is still a work in progress at this time, the ISO believes that the proposals presented in this document and in the October 1st Elements document recently released by the ISO are consistent with both the intent and the specifics of the SMD as FERC has articulated them thus far. In Section 2 of this document the ISO provides a table laying out in detail how the ISO's Comprehensive Design, in each of its implementation phases identified above, aligns with the elements of the SMD.

1.1.5 Public Review and Comment

In developing the present Draft Comprehensive Design Proposal the ISO has provided several opportunities for review and discussion by the public and has participated in FERC-sponsored public workshops on ISO market design, including:

- An initial draft released on December 21, 2001, as advance notification of the objectives, scope and initial activities of the MD02 project;
- A Preliminary Draft Comprehensive Design Proposal released on January 8, 2002, which stated the goals and guiding principles of the MD02 project and presented ISO staff's preliminary design thinking in considerable detail;
- A series of four 6-hour public focus groups on January 14-17 to discuss the January 8 Draft;
- A formal solicitation of written comments following the focus groups (due Jan. 23);
- A Revised Draft Comprehensive Design Proposal released on January 28 indicating significant changes to the content and time frame of MD02 based on ISO Management's responses to received comments; a formal solicitation of written comments on this draft (due Jan. 31).
- A series of 6-hour public focus groups on March 18-20 to discuss design elements;
- A draft October 1st Elements paper released on March 29; a formal solicitation of comments on this draft, due April 3.
- A revised draft Comprehensive Design Proposal released on April 3, which included explicit sections of stakeholder comments and ISO responses for each major design element; a formal solicitation of comments on this draft, due April 11;
- Two days of FERC-sponsored public meetings on ISO market design on April 4-5;
- A stakeholder forum on April 9, following the Board meeting on that date.

NOTE: A summary of stakeholder comments on this Comprehensive Design Proposal with ISO responses is provided as Appendix C to the present document.

1.2 Underlying Assumptions and Key Dependencies

The ISO's Comprehensive Design proposal assumes that California's electricity industry will retain certain basic structural elements established by AB 1890 and FERC Order 888. To be specific:

1. The electric transportation system within California will consist of a FERC-regulated transmission system and state- or locally-regulated distribution systems.
2. California will continue to have a mix of investor-owned utilities (IOUs) and publicly-owned utilities that, at a minimum, operate electric distribution systems and may, in addition, own and/or operate generation and transmission facilities, engage in wholesale marketing, and supply electricity to retail end-use consumers.
3. Some portion of the generation resources within California will be owned by entities that are not distribution utilities and hence are not inherently dedicated to any particular service territory. These resources will operate under market-based rates and will be free to sell into markets or to buyers of their choosing both within and outside of California.

4. California will continue to have an Independent System Operator (ISO) whose core functions include the following:
    - Reliably operate the transmission system that comprises its control area;
    - Provide non-discriminatory access to the transmission system under its control;
    - Procure the generation services needed for reliable operation (e.g., operating reserves and real-time balancing energy) in an efficient and cost-effective manner; and;
    - Provide adequate and timely information to all users of the ISO-controlled grid.

In addition to the above, this proposal assumes that the following conditions will exist in the long term. These conditions are required for this proposal to be fully effective.

5. All entities responsible for performing the key functions of electricity supply[2] will be creditworthy and fully capable of performing their designated functions.
6. In particular, all load serving entities (LSEs) will be creditworthy buyers, and the state-regulated LSEs will have clear, workable rules regarding supply procurement and cost recovery.
7. State policy makers and appropriate agencies will have defined and implemented an effective state role in ensuring supply adequacy for California's consumers.
8. Settlement of ISO-related transactions will be reliable and timely.
9. California will continue to rely on imported energy to meet a significant portion of in-state demand at certain times, and will have excess energy to sell out-of-state at other times.
10. Retail supply within each distribution utility's service territory may be performed by the distribution utility itself, in part or in full, and may or may not feature "direct access" by end-use customers to non-utility retail suppliers.

The ISO recognizes, however, that the conditions required by the long-term design will take some time to realize. This Comprehensive Design therefore assumes the following as likely conditions to prevail when the October 1st Elements are proposed to take effect:[3]

11. At least one of the IOUs operating as a LSE in California will not be creditworthy, and hence will not be able to fully meet its supply obligations without additional support.
12. The procurement and cost recovery rules for IOUs that serve California load may not be finalized by the California Public Utilities Commission (CPUC).
13. The California Energy Resource Scheduler (CERS) will be responsible for filling the supply gap that can not be covered by non-creditworthy IOUs and for providing financial backing for supplies procured through the ISO markets, at least until January 1, 2003.
14. Prior to January 1, 2003 the state will either extend CERS's existing roles or authorize another entity to fill these roles until all LSEs are fully creditworthy and functional. Unless

2 The key component functions required for the supply of electric service to end-use consumers are generation, transmission, distribution, and wholesale and retail supply. The first three of these involve operation of the physical assets required for the production and delivery of electricity, while the last two are commercial functions that may be performed by entities that do not operate any of these physical assets. These functions are defined more precisely in Section 4 of this document.

3 Readers should refer to the ISO's Third Quarterly Report on Market Conditions, filed with FERC on March 26, 2002, for additional information regarding near-term market conditions.

there is another designated creditworthy backer of ISO transactions, the ISO will not be able to fulfill its core functions.

15. The state-procured power contracts (i.e., the CERS contracts) will continue to provide a significant share of the supply needed to meet IOU load. If the state succeeds in its efforts to overturn these contracts, the state or the IOUs will need another means to obtain the required supply, as it is not likely that such volumes could be procured through the ISO spot markets at reasonable prices and without jeopardizing reliable operation.
16. Some of the factors originally identified as root causes of the California electricity crisis will not be fully remedied by October 2002. In particular: (a) there may still be shortages of supply at certain times, giving rise to supplier market power in the ISO control area; (b) there will still be transmission constraints that severely limit the competitiveness of supply in local areas at certain times; (c) there will be limited demand responsiveness, exacerbating supplier market power; and (d) the most significant market design changes proposed by the ISO can not be implemented until spring 2003 at the earliest, including the new congestion management design and the creation of an integrated day-ahead energy market.
17. Some improvement regarding the root causes will have been achieved, particularly the increased volume of forward contracting and commensurate reduction in reliance on spot markets, as well as the installation of significant new generation in California.

1.3 The Elements of the Comprehensive Design Proposal

The primary design effort on this project has been assigned to an inter-departmental team of ISO staff referred to as the MD02 team. The elements that comprise this Proposal were crafted from the MD02 team's synthesis of a number of materials, including: (1) staff analysis of the root causes of California's power crisis, (2) four years of experience operating the ISO markets and the grid, (3) the design and performance of other ISOs and the numerous rulings FERC has made on their filings, (4) the design elements of the January 2001 Congestion Management Reform proposal developed through an inter-departmental ISO staff effort, and (5) the design elements of the April 2001 Market Stabilization Plan developed by the ISO to ensure market and operating stability over summer 2001. In addition this draft has benefited from the input of stakeholders in numerous public meetings held at the ISO over the past two years, particularly in the context of developing items (4) and (5) above and over the last few months in connection with the MD02 effort itself.

As a result of this synthesis, the Proposal presented in this document retains some of the successful elements of the ISO's existing design, adopts design elements that have proven successful in other ISOs, and in some areas develops original proposals to address as yet unsolved problems. The principles that have guided the MD02 effort are:

1. improve upon the ISO's performance of its core functions, particularly the provision of non-discriminatory transmission service and reliable operation of the grid;
2. identify and address the root causes of problems; in particular, provide incentives and means for buyers to limit their exposure to volatile spot prices and for suppliers to fully offer all available capacity to the market;
3. ensure that forward market price signals, incentives, and transmission allocation rules are consistent with and support real-time operating needs;

4. design for flexibility and open architecture so the market design and the implementing systems are adaptable to changes, such as key FERC rulings expected over the coming year and the development of Regional Transmission Organizations in the west;
5. strive for simplicity and transparency, and make the ISO a more attractive place for all participants to do business;
6. provide adequate, timely, and transparent information, tools and incentives for market participants to self-manage their business activities and risks in the forward markets;
7. accommodate the needs of diverse ISO participants, including municipal and other vertically-integrated utilities that use the ISO grid and markets; and
8. support the creation of a seamless western market by addressing seams issues.[4]

The major component elements of this Comprehensive Design Proposal are:

- **Available Capacity (ACAP) Obligation on Load Serving Entities.** The main purpose of the ACAP obligation is to enable the ISO to verify in advance that adequate capacity is available on a daily basis to meet system load and reserve requirements. Thus, the ISO believes that the proposed ACAP Obligation is essential to the ISO's core function – that of providing reliable transmission service. Under Assembly Bill 1890 (AB 1890), the ISO is required to ensure efficient use and reliable operation of the transmission grid consistent with the achievement of planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council (WSCC). The ACAP proposal is consistent with, and supports, that statutory requirement. Specifically, as proposed, the ACAP Obligation will support reliable system operations by requiring LSEs to procure, in a forward-market timeframe, resources sufficient to satisfy the ISO's peak daily operating requirements. Moreover, by requiring that such ACAP resources are made available to the ISO in the day-ahead market, the ISO can satisfy its objective of moving operating decisions from real time into the forward market – further supporting stable and reliable operations.

  Recognizing that ACAP is a new element of the California energy market, and that it places new responsibilities and requirements on certain entities, the ISO proposes to transition, over a four-year period, to full ACAP implementation. That consideration notwithstanding, it is imperative that all affected parties begin immediately the substantial task of developing the operational, market, regulatory, and information-based systems necessary to implement the ACAP requirement.

  It is important to note that the ACAP Obligation is probably the one element of the proposal for which the roles of state entities and policy makers are most important. Specifically, the rules and practices under which the investor-owned utilities (IOUs) – the largest load-serving entities in California – procure ACAP and the rules for their recovery of associated costs are regulated by the CPUC. In addition, the California Power Authority will likely have a significant role in procuring resources (e.g., generating capacity, forward contracts, and demand-side programs) that meet some portion of the ACAP obligations of California load-serving entities. In addition, the power contracts negotiated by the state early in 2001 and currently administered by CERS will continue to comprise a significant share of California's supply. Finally, the question of long-term supply adequacy is a matter for state policy that must engage all policy makers and entities concerned with the functioning of the energy

[4] Because of California's high level of dependence on imported energy to meet its needs, seams issues must be addressed in ISO market design. These inter-control area coordination issues exist and must be resolved no matter how California's involvement in the evolution Regional Transmission Organizations (RTOs) in the western region unfolds.

market. Thus, while it is important for the ISO's performance of its core functions to define and verify compliance with the ACAP obligation, the ACAP Obligation alone is not sufficient to ensure adequate supply capacity for California, neither in the long term nor the near term. Supply adequacy is a problem that extends beyond the ISO and depends on effective state policy and on the actions of these other entities.

- **Day Ahead Congestion Management.** The ISO proposes to use a fully accurate model of the ISO transmission grid to adjust generation and load (and import and export) schedules to mitigate transmission overloads, ensure local reliability and, in the process, produce locational marginal energy prices at each node of the grid. With this change the ISO will eliminate the distinction between inter-zonal and intra-zonal congestion, will eliminate the "Market Separation Rule," and will conduct a forward spot energy market in the process of managing congestion. The proposed design will still allow Scheduling Coordinators (SCs) to establish firm physical schedules if they wish, and will accommodate commercial energy trading at a few key "trading hubs."
- **Forward Spot Energy Market.** With the demise of the Power Exchange the California energy market lost the primary vehicle for day-ahead energy trades to shape supplies to meet the next-day's expected demand. Even without the ISO explicitly creating a new spot market, the proposed congestion management approach would result in energy trading among participants anyway. With forward congestion management and forward energy trading thus integrated, there will not likely be a need to create a separate new market similar to the Power Exchange. The economic dispatch algorithm that performs integrated energy and congestion management will simultaneously procure ancillary services and perform a voluntary unit commitment service.
- **Firm Transmission Rights (FTRs).** These are financial instruments that allow participants to hedge the risk of congestion charges. With the changes to congestion management as proposed above, the ISO will also need to change the design of its FTRs from the current path-specific variety to a point-to-point design that specifies explicit generator and load locations without explicit reference to the network pathways affected.
- **Ancillary Services Markets.** The ISO proposes to perform ancillary service procurement simultaneously with day ahead congestion management and the energy market, to obtain Operating Reserves and Regulation. The proposed Comprehensive Design will allow the ISO to eliminate Replacement Reserves.
- **Residual Day Ahead Unit Commitment.** Unit commitment refers to the decision to start up a generating resource that has a long start-up time, so that it will be running at the time it is expected to be needed to meet demand. The original design of the ISO leaves commitment decisions entirely to participants and gives the ISO no ability to commit additional units in advance even when the forecast indicates they will be needed. Under the proposal, the ISO would evaluate whether day-ahead schedules include enough on-line resources to meet the next day's demand forecast, and if not, the ISO would be able to commit additional units. The ACAP obligation mentioned above would ensure that adequate units are available and are required to respond to ISO commitment instructions.
- **Changes to Structure and Timing of Hour Ahead Market.** Numerous parties have expressed a need to move the hour-ahead market closer to real time, to enable late energy trades and schedule changes to shape supplies as accurately as possible to meet demand. The ISO is considering a simplified hour ahead market that would perform congestion management and energy trading, and would close to submissions perhaps as late as 60 minutes before the start of the operating hour. This change would also satisfy a long-standing demand by many parties for a 60-minute dispatch market, since real-time energy

bids submitted to the hour-ahead market could be matched against load bids for the next hour or pre-dispatched by the ISO for imbalance energy.

- **Real-time Economic Dispatch Using Full Network Model.** Every 10 minutes during each operating hour the ISO would run a "security-constrained economic dispatch" program to determine which resources to dispatch at what operating levels to meet real time needs. This approach would meet the ISO's operating needs most accurately and efficiently by fully taking into account all transmission constraints, local reliability needs, and generator operating constraints, as well as system imbalance energy needs. This approach would produce nodal real-time energy prices, which would be paid to supply resources but could be aggregated to larger geographic areas for settling imbalance energy purchases by load serving entities. This change would also eliminate the current two-price system (separate INC and DEC prices in each interval), and would thus make it necessary to apply a system of penalties for resources that vary from ISO dispatch instructions beyond a reasonable tolerance band. Such a system of penalties was proposed for early implementation by the ISO in Amendment 42, recently rejected by FERC because it was filed separately rather than as an element of a comprehensive design. Since this design element in an essential component of the Comprehensive Design, the ISO will resubmit these penalty provisions in its May 1 filing.
- **Bid Mitigation for Local Reliability Needs.** FERC has granted mitigation measures against local market power to the other ISOs. The ISO's Comprehensive Market Design includes such mitigation in both the forward and the real-time markets. The forward market mitigation of incremental bids that are needed out of economic merit order due to locational needs follows the same logic and principles regardless of the granularity of the underlying network model used. Regarding local market power in the decremental bid market, nodal pricing should provide a natural mitigation in the first settlement market (i.e., the day ahead). However, short of strict activity rules (such as precluding bidders from submitting arbitrary decremental bids after the close of the day ahead market), local market power in the supply of decremental bids can emerge in the subsequent markets, again regardless of the granularity of the underlying network model. Such activity rules can be implemented when the ISO starts a forward energy market. With or without a forward energy market, bid mitigation for local reliability is still a needed feature of the real time market.
- **Damage Control Price Cap on ISO Markets.** To mitigate against excessive market power abuse, the ISO proposes a Damage Control Bid Cap (DCBC) that will limit the maximum bid allowed in the ISO's energy and ancillary service capacity markets. Since the ACAP Obligation will not be effective immediately, to protect against market power in the transition period, the ISO believes it is prudent to start with a relatively low DCBC and gradually raise it as capacity conditions improve. Beginning on October 1, 2002 and until market conditions are competitive enough to support a higher DCBC, the ISO proposes to set the DCBC at the current level of $108 per MWh, and to increase the DCBC in response to increases in the price of natural gas in accordance with the formulation approved by FERC in conjunction with the existing market mitigation provisions.[5] in addition the ISO proposes to increase the level of the DCBC over time as the structural elements necessary to support a competitive market improve and believes that the DCBC could eventually be increased to $1,000/MWh,

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5 The proposed DCBC would be a hard cap (i.e., bids above the DCBC would be rejected rather than accepted subject to justification as they would be under a soft cap), and the $108 per MWh value would represent a floor in the sense that the cap could increase but not decrease in response to gas price movements. The applicable methodology for adjusting the DCBC is described in FERC's December 19, 2001 "Order Temporarily Modifying the West-wide Price Mitigation Methodology."

which is the bid cap level currently in place in the eastern ISOs. However, the ISO does not believe it is appropriate to set specific dates for when the DCBC would increase because such dates would be arbitrary. The decision to raise the DCBC will be based on an assessment of overall competitiveness of the market rather than an arbitrary date.

- **Bid Screens and Mitigation.** Beginning on October 1, the ISO proposes to implement individual resource bid screens and mitigation procedures in the day ahead Residual Unit Commitment process and in the real time pre-dispatch process that occurs 45 minutes prior to the start of the operating hour. In the Comprehensive Design this procedure would also be applied to the integrated forward energy and congestion management markets. The procedure involves mitigating energy bids that (a) exceed an explicit threshold level and (b) have a material impact on projected market clearing prices. This mitigation element is similar to the Automatic Mitigation Procedures (AMP) utilized by the NY ISO, but would have more stringent bid and impact threshold levels. The ISO recommends that bid reference levels be based on historical bids for all resources. The ISO further proposes a bid threshold equal to the lower of a 100% increase from a resource’s reference level or $50/MWh, and a market impact threshold equal to the lower of a 100% increase or an increase of $50/MWh in the projected real-time market clearing price. This procedure would apply to all bidders into the markets to which the procedure is applied. As the ISO gains experience with the bid screen and mitigation procedures and if the overall competitiveness of the ISO markets improves, the ISO will consider raising the bid and price impact threshold levels.
- **12-month Market Competitiveness Index and Pre-authorized Additional Mitigation Provisions.** The fundamental objective underlying electricity market restructuring and implicit in all FERC Orders regarding ISOs and RTOs is that they will promote competition and provide for an efficient power market in order to bring cost savings to consumers over the regulated structure. These objectives have not been measured, however, and indeed can turn out to be unachievable if there are structural problems in the market and significant abuse of market power. The ISO believes it is imperative that FERC clearly define market power and commit to a tangible standard to measure just and reasonable rates in those ISOs that have market based rate authority. The ISO proposes an objective and explicit standard by which just and reasonable rates can be measured and tracked over time. The proposed standard uses a 12-month rolling price-cost markup index that compares actual average market cost to a competitive baseline average cost. The competitive baseline would be based on an explicit and transparent methodology that calculates the marginal cost of the highest cost unit available to serve system load each hour. If the 12-month rolling average markup is above $5/MWh, the market should be declared unjust and unreasonable. Once the market is declared non-competitive, the ISO would have the pre-authorized ability to reinstate FERC’s west-wide mitigation and to apply cost-based proxy bid mitigation in all hours for six months, or until FERC and the ISO develop more permanent solutions, or until market conditions are determined to be competitive.
- **Penalties for Excessive Uninstructed Deviations.** A fundamental requirement of reliable real time operation and market stability is that suppliers who make firm commitments, via their accepted schedules and bids, to perform in a particular manner be required to fulfill such commitments or face appropriate consequences. In Amendment 42 the ISO proposed to address this need through a system of penalties to be imposed on suppliers that engage in excessive uninstructed deviations. The ISO believes this element is both essential for predictable real time performance and an important market power mitigation element that will reduce physical withholding. Although FERC rejected this element of Amendment 42, the ISO believes it must be included as part of the Comprehensive Design if this design is to

achieve its objectives, and therefore the ISO will resubmit these provisions as part of the May 1 tariff filing.

In addition to these major design elements there are three important issues that need to be highlighted.

- **Scheduling and Settlement of Loads.** A crucial feature in the locational marginal pricing (LMP) market design the ISO is proposing is the geographic granularity used for scheduling and financial settlement of loads. The major changes will occur when the ISO implements the full network model in the forward energy and congestion management markets, when nodal prices for energy will be produced in the forward and real time energy markets. If the costs of energy to serve consumers in different locations are significantly different, there could be significant cost impacts introduced by the adoption of LMP. Today, locational differences in energy costs are hidden because energy prices in the ISO's real time market are no more granular than the major congestion zones. Even when there is intra-zonal congestion, the costs are spread across the major congestion zones, and the costs of RMR for local reliability are spread to entire PTO service territories as well as other users of the transmission system.

  The fundamental tradeoff to be considered is between (1) sending strong locational price signals to all market participants, to maximize the incentive effects of LMP for investment in transmission, location of new generation, forward contracting and demand responsiveness, and (2) the potential for severe cost impacts on consumers in congested areas due to constraints in a transmission system that was designed and built under an entirely different regulatory regime, one which did not anticipate competitive generation markets and locational pricing. The second point raises legitimate issues of fairness, which are addressed below. It also requires that we try to address in a realistic manner the question of how to upgrade transmission into congested areas to enable consumers in these areas to enjoy the benefits of competitive energy markets.

  In recognition of these issues the ISO proposes to utilize Load Aggregations as a permanent feature of the new design. When nodal pricing begins operation with the implementation of the full network model in fall of 2003, the ISO proposes to schedule and settle loads at the Demand Zone level, and to migrate when technically feasible to the Load Group level.[6] The ISO also proposes to allow LSEs to create custom Load Aggregations for scheduling, and settlement when feasible, using the actual nodes at which they serve load, provided there is appropriate revenue quality metering to enable the ISO to verify the accuracy of the custom aggregation. Individually loads with adequate metering and metered subsystems may also elect locational pricing that coincides with their actual locations.

  In addition, to mitigate the impact of congestion costs to loads under the proposed LMP design, the ISO proposes to provide an initial allocation of Firm Transmission Rights (FTRs) to loads based on their historic load levels and grid use patterns. These FTRs will effectively neutralize the impact of any congestion charges resulting from LMP in the day ahead market. FTRs are not likely, however, to fully eliminate the locational impact on loads when high-cost generation must be procured to serve their needs due to congestion constraints. Refer to Section 5.3 for a more detailed explanation of the allocation of FTRs to loads and an example to illustrate the effect of FTRs in mitigating congestion costs.

  Finally, to address the problem of transmission constraints the ISO is committed to a proactive transmission expansion process; a process that results in appropriate and timely

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6 There are roughly 20 Demand Zones within the ISO control area, and just over 40 Load Groups identified at this time; for a complete list see the table of Load Aggregations in Section 5.8.

expansion of the ISO Controlled Grid. Moreover, the ISO is committed to a proactive transmission planning and expansion process that is tightly integrated with both its ACAP and RMR policies. While a satisfactory answer to the transmission question is beyond the scope of ISO market redesign, the ISO will pursue efforts to further expand the system in parallel with the market redesign effort. See Section 5.1 for additional discussion of this topic.

- **Existing Transmission Contracts.** One design issue that does not yet have a completely satisfactory solution in this proposal relates to Existing Transmission Contracts (ETCs). Since the beginning of ISO operation, ETC holders have been able to reserve transmission capacity beyond the close of the day ahead market, up through the running of the hour ahead market and nearly up to the start of the Operating Hour, even though the ETC holders may not actually use all this capacity in real time. This provision for ETCs forces the ISO to perform congestion management as if all the ETC capacity is fully scheduled, thus frequently creating artificial or "phantom" congestion in the forward markets which can lead to extremely inefficient allocation of the grid. The ISO's ultimate objective in market redesign is therefore to perform all transmission allocation through a single congestion management and firm transmission rights (FTR) system, according to a single set of rules and a common scheduling time line. To achieve this objective will require converting all ETCs to FTRs and thus eliminating the need for separate scheduling provisions for ETCs. FERC's recent Options Paper on the Standard Market Design expresses concern about incompatibilities between ETCs and the LMP approach, and supports the objective of eventually treating all grid users according to a common Open Access Transmission Tariff.

  Toward this end the ISO will continue to work with ETC holders to find mutually agreeable terms for conversion of ETCs to FTRs and full compatibility with the ISO's scheduling time line. The ISO recognizes, however, that some quantity of ETCs may continue to exist in their present form at the time the ISO implements the comprehensive design. The proposed FTR design and the process for release of FTRs therefore includes provisions for transmission capacity to be set aside for non-converted ETCs as well as for ETCs that convert to FTRs. In addition, to minimize the adverse impacts of phantom congestion as long as there exists a significant quantity of non-converted ETCs the ISO is considering offering a Recallable Transmission Service (RTS) after the running of the forward congestion markets.

- **Treatment of Governmental Entities.** The ISO is currently engaged in an effort to develop a refined Metered Subsystem (MSS) proposal, to address concerns raised regarding the integration of Governmental Entities ("GE") into ISO operations, as expressed in the recent Federal Energy Regulatory Commission ("FERC") audit.[7] The refined MSS proposal is also intended to address the circumstances where a GE's existing Interconnection Agreement ("IA") or other umbrella Existing Contract with the relevant transmission owner terminates such that the GE is necessarily compelled to establish a new relationship with the ISO.

  The objective of the MSS concept and the current MSS proposal is to develop a workable market participation model for GEs, including but not limited to scheduling, operations and settlement. The proposal is intended to address the problems perceived with the ISO's structure as it affects a GE's obligation to serve the customers in its Service Area and GE tax-exempt financing issues. The proposal includes a provision that the GE will affirmatively accept the obligation to serve its Load and the option for the GE to follow such Load with minimal, if any, economic or operational impacts on the ISO. For the ISO, it must continue to honor Existing Contracts, allocate costs based on cost causation principles and minimize

[7] Governmental Entities may include municipal utilities, state agencies, water districts, irrigation districts and federal agencies.

cost-shifting among Market Participants. These steps hopefully will encourage GEs to more fully integrate with the ISO.

The ISO is the Control Area operator of both the ISO Controlled Grid and non-ISO Controlled Grid facilities. This dual role, and the fact that the ISO does not generally have access to detailed information regarding the status and scheduling of non-ISO-grid facilities, has hampered the ISO's functioning in the past. These issues are important because of the operational difficulties created by having two classes of participants and the "holes" it makes in the Control Area. By recognizing the differences among participants and reaching a resolution to such differences between GEs and other Market Participants through the MSS proposal, the originally anticipated efficiencies of a single ISO Control Area may be achieved.

1.4 Relationship of Comprehensive Design to the October 1st Elements

To date the FERC mitigation provisions enacted in the June 19, 2001 Order and related FERC decisions have been helpful in limiting the exercise of market power. Specifically, the must-offer obligation has targeted physical withholding while the price cap in non-emergency hours and the use of proxy bids in emergency hours have targeted economic withholding. In light of FERC's December 19, 2001 Order on Rehearing, which denied the ISO's motion to extend the stated September 30, 2002 expiration of mitigation until there is an adequate demonstration that the markets are workably competitive, the ISO has attempted to develop mitigation elements that would be helpful in mitigating market power after September 30. These elements – identified as "October 1st Elements" and fully described in the document of that title released by the ISO on March 29, 2002[8] – are actually elements of the Comprehensive Design, but ones that must be implemented by September 30 to be in place when the existing mitigation established by FERC is due to expire. In some instances these elements are modified somewhat from their long term design to compensate for the fact that the entire Comprehensive Design package can not be implemented at the same time. The main point is that the October 1st Elements should not be thought of simply as interim measures, but as components of a fully integrated, comprehensive redesign of the ISO markets that will be implemented at a later date, pending FERC approval.

The date of full effectiveness of the proposed long term Comprehensive Design – and hence the duration of the interim features and parameters specified in the October 1st Elements – can not be confidently predicted at this time, due to the nature of the underlying structural conditions that must be resolved and the actions required by policy makers and other entities. Purely in terms of the implementation effort required, the ISO believes it can implement the new market structure embodied in this Comprehensive Design proposal (specifically the integrated day ahead and hour ahead energy markets, congestion management, ancillary services and unit commitment based on locational marginal pricing using a full network model, and redesign of firm transmission rights) in two phases beginning in the spring of 2003 and concluding in the fall

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8 Based on guidance from the ISO Board of Governors at their April 9 meeting, ISO management has modified some of the provisions of the October 1st Elements as originally laid out in the March 29 document. These modifications are described in a separate document that is available on the ISO web site as part of the Board package for the April 25 meeting. In addition to the changes indicated in the April 25 Board package, the ISO has modified its proposed initial Damage Control Bid Cap level to reflect the Board's April 25 decision, as indicated earlier in this section.

of 2003, provided FERC expeditiously approves the Comprehensive Design without extensive modification.

1.5 Market Changes Proposed in Amendment 42

On March 27, 2002 FERC issued an order rejecting certain elements of the ISO's Amendment 42 filing which the ISO believes are necessary components of the Comprehensive Design. The specific elements in question are:

1. Real time economic dispatch, which would eliminate the problematic "target price" mechanism, eliminate the separate INC and DEC prices and create a single price in each 10-minute interval thus creating a need for explicit penalties for uninstructed deviations;
2. Penalties for uninstructed deviations;
3. Real time bid mitigation for local reliability needs, including intra-zonal congestion, under both normal operating conditions and when transmission facilities are out of service or derated;
4. Day ahead scheduling limits on generating resources in areas of the grid that would exhibit real time intra-zonal congestion in the absence of such limits.

The ISO had filed these elements as a separate amendment in advance of the Comprehensive Design proposal because they (a) address well-known flaws in the ISO's market design that continue to cause operational problems today, and (b) are implementable in a way that is fully consistent with and supports the transition to the Comprehensive Design.

In earlier versions of this Comprehensive Design proposal the ISO has assumed that these Amendment 42 elements would be approved and in place prior to Summer 2002. In light of FERC's recent rejection, the ISO has incorporated these elements more explicitly into the present document as elements of the Comprehensive Design, and also intends to include some of them in its May 1 filing of the October 1st Elements. As this document is being finalized for filing, however, the ISO has been engaged in discussions with stakeholders to develop an alternative approach for interim forward intra-zonal congestion management. The ISO has therefore taken this element out of its May 1 Tariff filing and will, upon the conclusion of these discussions, submit its preferred approach to FERC in a separate tariff filing.

In the present document the reader will find discussion of the rejected Amendment 42 elements in the following sections:

- Real time economic dispatch – Section 5.7;
- Penalties for uninstructed deviations – Section 5.13;
- Real time bid mitigation for local reliability needs – Section 5.9;
- Day ahead scheduling limits – Section 5.2.

2 Introduction

This document presents the recommended elements of the ISO's Comprehensive Market Design Proposal, as developed in the course of the ISO's Market Design 2002 (MD02) project.[9] To provide context and motivation for the proposal, this section begins with an overview of the electricity crisis that began in 2002, identifies some other factors driving the need to redesign California's markets, and describes the objectives, guiding principles and organization of the MD02 project.

ISO Management initiated the MD02 project to (1) take a comprehensive view of the changes needed in the structure of California's electricity markets, with a focus on those markets that are operated by the ISO in performance of its core functions, and (2) develop an integrated program of proposed market design changes that will address current problems in a systematic fashion and create a framework for a sustainable, workably competitive electric industry that benefits all California consumers and is compatible with the rest of the western region.

2.1 Root Causes of California's Electricity Crisis

Since the beginning of the electricity crisis in Summer 2000, the ISO has been assessing the structural features and design elements of the restructured California markets that contributed to the crisis. In an early report on the subject the ISO identified the following root causes:

- Tight supply conditions in California and throughout the western region;
- Under-scheduling in the forward markets, which increases the volume of the ISO real-time market far beyond its original design and raises the cost and difficulty of ensuring reliable operation of the grid;
- Lack of demand responsiveness to hourly prices, due to (a) limited technical capability for real-time price-responsiveness; (b) insufficient forward contracting for energy; and (c) ambiguous accountability for reasonably-priced power acquisition for retail consumers;
- Exercise of market power, both at the system-wide level and in connection with local reliability needs;
- Inadequate transmission capacity to support competitive markets throughout the ISO system; and
- Needed enhancements to market rules to improve market efficiency and to ensure that forward schedules are feasible.

Clearly not all of the above problems are resolvable through ISO market design changes. In particular, tight supply in the western region, limited demand responsiveness, and inadequate transmission infrastructure are areas where ISO market design changes will contribute only partially to the solution.

2.2 Reform of the ISO's Congestion Management

Even before the crisis began in Summer 2000, FERC's January 2000 rejection of locational market power mitigation provisions of the ISO's Amendment #23 had prompted the ISO to

[9] Earlier drafts of the MD02 Comprehensive Design Proposal were released publicly on January 8 and February 2, 2002, and are posted on the ISO's web site.

initiate a project to correct fundamental flaws in its congestion management procedures. This Congestion Management Reform (CMR) project held extensive stakeholder meetings in the process of assessing design options, and culminated in the CMR proposal of January 2001 which is available on the ISO web site. At that time, however, the ISO was unable to move forward to seek FERC approval or to implement this proposal due to the ongoing power crisis.

2.3 The ISO's Market Stabilization Plan

During the winter and spring of 2001, anticipating potential shortages in the coming summer the ISO developed a Market Stabilization Plan (MSP) to ensure adequate supply and to mitigate market power. As in the case of CMR, the ISO held stakeholder meetings to discuss the options being considered in the MSP. During the same period FERC was developing its preferred market mitigation plan for California and the western region, and in this context ordered the ISO to file the MSP on April 6. The ISO's MSP filing is also available on the ISO web site.

2.4 FERC's Market Mitigation Orders

FERC issued its initial order to provide market mitigation for Summer 2001 on April 26, 2001, followed by a second order on June 19 that revised, clarified and expanded upon the April 26 order. Then on December 19 FERC issued extensive orders responding to the ISO's compliance with the mitigation orders and addressing the clarification and rehearing filings that the ISO and numerous other parties had made. These orders and the ISO's implementation of their provisions collectively comprise the market mitigation framework that exists in California today and is due to expire on September 30, 2002.[10] This framework provides a number of important provisions which have helped ensure stability and reasonable prices in the ISO's markets. The major provisions include:

- The requirement for all in-state non-hydro generating units to bid all available capacity into the ISO's real-time market in all hours (the "Must Offer Obligation"); for long-start-time units this obligation extends into the day-ahead time frame to enable the ISO to issue start-up instructions (or deny shut-down requests) for units the ISO expects to need to dispatch the next day;
- Price mitigation in the real-time market in all hours; in particular, a cap on the real-time market clearing price (MCP) during non-emergency hours that is based on the highest-cost in-state generator that ran during the most recent Stage 1 System Emergency (the "Non-Emergency Clearing Price Limit" or NECPL), with cost justification required for bids exceeding the cap; during declared system emergencies the ISO may set market prices based on unit-specific cost-based proxy bids;
- The requirement that marketers (i.e., suppliers whose supply can not be tied to a specific generating unit) bidding into the real-time market be paid at the MCP but not be able to set the MCP (the "Price Taker" requirement).

[10] On December 19, 2001 FERC issued an Order denying the ISO's motion for rehearing of the September 30 expiration date. We had argued that the date was arbitrary and that to remove mitigation without a determination that the ISO markets were no longer subject to manipulation through the exercise of market power was an abrogation of FERC's responsibilities under the Federal Power Act to ensure just and reasonable rates. With FERC's denial of the ISO's motion, the only remaining recourse to seek reversal of this decision is through judicial review, which ISO Management initiated on February 14 in a petition submitted to the U.S. Court of Appeals for the Ninth Circuit.

The ISO believes that the provisions of these market mitigation orders have helped to ensure adequate supply in real time at reasonable prices. We are concerned, however, for reasons discussed further below, that not all features of the comprehensive market design discussed in this document can be fully implemented by September 30 when the mitigation orders expire. The MD02 effort has therefore placed great emphasis on identifying the essential provisions that will be needed at that time to ensure continued operational and market stability. In this proposal we identify a specific package of elements – the "October 1st Elements" – that we propose to implement by September 30 to try to maintain stable markets and reliable operation when the existing mitigation provisions expire.

2.5 FERC's Standard Market Design Proceeding

In 2001 the Federal Energy Regulatory Commission (FERC) initiated a Standard Market Design (SMD) proceeding, to specify the elements of an optimal electricity market structure for ISOs and RTOs. Towards this end FERC issued a Staff Paper in December 2001, a Commission Working Paper on March 15, 2002, and an Options Paper on April 10, which provided a strong sense of FERC's preferences with regard to market design and identified areas where additional work and consideration are required. The ISO has participated in FERC-sponsored activities related to the SMD and has paid close attention to FERC's guidance and preferences in developing the Comprehensive Design Proposal and the October 1st Elements. Although the SMD is still a work in progress at this time, the ISO believes that the proposals presented in this document and in the October 1st Elements document recently released by the ISO are consistent with both the intent and the specifics of the SMD as FERC has articulated them thus far. In the following pages the ISO provides a table laying out in detail how the ISO's Comprehensive Design Proposal, including the October 1st Elements, aligns with the elements of the SMD.

Comparison of MD02 and FERC's Standard Market Designs

	CAISO CURRENT	CAISO PROPOSED (10/1/02)	CAISO PROPOSED (long-term)	FERC STANDARD MARKET DESIGN
Prior to Day Ahead				
Capacity Obligation &/or Market	None	Available Capacity (ACAP) Obligation: Since ACAP will not be implemented initially, for the October 1, 2002 implementation, the ISO is considering extending the "must offer" obligation to serve California in return for some type of capacity payment.	Available Capacity (ACAP) Obligation: Load-serving entities (LSEs) will have an Available Capacity Obligation, defined as a margin above their monthly peak load, to be met by a combination of own generation, firm energy contracts, capacity contracts, and demand-side management. ISO will verify compliance monthly and assess penalties for any shortfall. Designated ACAP resources will be required to be fully scheduled or bid into ISO markets to serve ISO control area load (and specifically, except for Long Start Time units not scheduled in the day-ahead market for energy or A/S, and not committed in the Residual Unit Commitment, bid all unscheduled available capacity in ISO's real-time market), and daily performance will be monitored. ISO verifies that load-serving entities meet their capacity obligations.	State and Regional reliability authorities to coordinate setting long-term reserve margin to be maintained by LSEs subject to their jurisdiction.
FTR Auction/Release **Financial or Physical**	Financial with a day-ahead physical scheduling priority	Financial with a day-ahead physical scheduling priority	Financial (Considering day-ahead physical scheduling priority on point-to-point FTRs)	Financial
Option or Obligation	Option	Option	Point-to-point obligations initially, adding point-to-point options and FGRs (Flowgate Rights) depending on need and technical feasibility.	Both option and obligation for source to sink rights as well as Flowgate rights
Revenue Stream/ or Offset CM Cost	Revenue stream on specific path	Revenue stream on specific path	Allow purchase for revenue stream as well as hedging for scheduling	Hedge for CM, not required for scheduling

	CAISO CURRENT	CAISO PROPOSED (10/1/02)	CAISO PROPOSED (long-term)	FERC STANDARD MARKET DESIGN
Duration	Annual (individual hours can be traded in secondary market)	Annual (individual hours can be traded in secondary market)	Three-year (30% of minimum ATC), Annual (45% of minimum ATC), and Monthly (the rest of ATC); allowing secondary trades of individual hours	Not specified
Definition	Direction and path specific (open loop/contract path)	Direction and path specific (open loop/contract path)	Direction specific (accounting for parallel path flows) Source-to-sink, where end points may be individual nodes or aggregations of nodes. Considering additional "flowgate" or path-specific rights (closed loop)	Should offer both: ➢ Source-to-sink (e.g. TCCs or NY/PJM FTRs) and ➢ "flowgate" or path-specific rights (closed loop)
Primary Release Mechanism	Auction	Auction	Allocation to ETC holders, converted ETCs, and Loads (LSEs), followed by auction for the remaining capacity.	Possibility of initial allocation to customers that pay the embedded costs of the system. Also possibility of auction (with proceeds credited to customers who paid for the system)
Secondary Market	ISO does not operate a secondary market, but requires FTR holders to register secondary trades.	ISO does not operate a secondary market, but requires FTR holders to register secondary trades.	Will not operate a secondary market, require FTR holders to register secondary trades.	Possibility for secondary trading with no RTO involvement.
Day Ahead				
<u>Energy Spot Market</u>	None after the demise of the PX	No forward energy market facilitated by the ISO for the September 30, 2002 implementation.	Integrated with Congestion Management: Simultaneous forward energy, Congestion and Ancillary Service markets (see below)	Integrated with Congestion Management; simultaneous forward Energy, Congestion and Ancillary Service markets (see below)
<u>Market Power Mitigation</u>	N/A	N/A	Damage control bid cap for real time market will also apply to the forward energy market Bid screen and mitigation procedures proposed for real time will also apply to the forward energy market	Damage control bid cap

	CAISO CURRENT	CAISO PROPOSED (10/1/02)	CAISO PROPOSED (long-term)	FERC STANDARD MARKET DESIGN
<u>**Congestion Management Market**</u> **Model spatial granularity**	Zonal; radial model. Any congestion within zones is ignored in forward CM and mitigated in real time.	Zonal; radial model. Any congestion within zones is ignored in forward CM and mitigated in real time.	Full network model (3000 busses including external loops)	Nodal pricing
Model objective function	DC optimal power flow with market separation	DC optimal power flow with market separation	Optimal power flow (tending towards DC OPF with pre-computed GMMs) without market separation (allowing for voluntary market separation)	Integrated with DA energy market (optimized simultaneously); bid cost minimization
Schedule Components	generation schedule at nodes at hourly intervals; Loads schedule at Demand Zones at hourly intervals optional inc/dec bids on generation and loads used for CM	generation schedule at nodes at hourly intervals; Loads schedule at Demand Zones at hourly intervals optional inc/dec bids on generation and loads used for CM	Generation schedule (and settle) at nodes at hourly intervals; LPAs act as trading hubs; Loads schedule (and settle) at LPA level at hourly intervals; optional inc/dec bids on generation and loads used for both CM and energy trades Provision for 3-part bids (cost-based start-up and minimum-load; bid-based energy)	Bid-based Settlement based on nodal prices; possibility to define trading hubs
Other Scheduling Requirements	Requires balanced schedule	Requires balanced schedule	Accepts balanced or unbalanced SC schedules. Require generation feasibility. Proxy prices to be on file for mitigating congestion with no competitive inc/dec bids.	Accepts balanced or unbalanced SC schedules. (No balanced schedule requirement) Provides for local (out of merit order) market power mitigation
Congestion Prices	Congestion prices in forward market are the difference between marginal INC and DEC bids (of the marginal SC) accepted for redispatch to clear congestion across the interface	Congestion prices in forward market are the difference between marginal INC and DEC bids (of the marginal SC) accepted for redispatch to clear congestion across the interface	Congestion prices (including the cost of losses) in forward market are the difference between hourly nodal energy prices.	Congestion Price (including losses) is calculated as difference between 2 locational prices; Acceptance of schedule is physical transmission right – right to physically inject energy at a location and simultaneously physically withdraw energy at another location. No congestion costs are socialized

	CAISO CURRENT	CAISO PROPOSED (10/1/02)	CAISO PROPOSED (long-term)	FERC STANDARD MARKET DESIGN
Ancillary Service Market **Services**	Spinning Reserves, Non-Spinning Reserves, Replacement Reserves, Regulation Up, and Regulation Down	Spinning Reserves, Non-Spinning Reserves, Replacement Reserves, Regulation Up, and Regulation Down	Spinning Reserves, Non-Spinning Reserves, and Regulation	Operating Reserves Market required of RTO: including at least AGC and 10-minute operating reserves.
ISO Acquisition or Self-provision	Both, SC's option	Both, SC's option	Both, SC's option	Both
Acquisition Mechanism	Auction after CM market closes; award based on capacity bids only; markets for Regulation (Up an Down), Spin, Non-spin, and Replacement cleared sequentially in that order; Rational Buyer procurement allows demand substitution, i.e., procurement of higher quality A/S in the sequence to substitute for the lower quality A/S when doing so reduces total A/S procurement cost.	Auction after CM market closes; award based on capacity bids only; markets for Regulation (Up an Down), Spin, Non-spin, and Replacement cleared sequentially in that order; Rational Buyer procurement allows demand substitution, i.e., procurement of higher quality A/S in the sequence to substitute for the lower quality A/S when doing so reduces total A/S procurement cost.	Simultaneous auction with energy based on bid-cost minimization (rather than the Rational Buyer type payment minimization objective function)	Simultaneously auction with DA energy and CM markets.
Bid Components	Regulation and Reserves: Bidders submit capacity and energy bids; energy bids are not used in the A/S capacity auction; they can be changed following the capacity auction; energy bids (except for Regulation) will compete in the real-time market with supplemental energy bids to determine dispatch merit order.	Regulation and Reserves: Bidders submit capacity and energy bids; energy bids are not used in the A/S capacity auction; they can be changed following the capacity auction; energy bids (except for Regulation) will compete in the real-time market with supplemental energy bids to determine dispatch merit order.	Energy and capacity bids will both be considered in the simultaneous auction; once selected, energy bids associated with the selected A/S capacity would not be allowed to be modified	Both generators and demand-side participants to offer products that meet requisite technical requirements Permit submission of both capacity availability and energy bids
Centralized Unit Commitment.	None in original ISO market design. Currently, CAISO commits long-start-up time units subject to the FERC June 19, 2001 must-offer obligation (current approach similar to proposal)	**Residual Unit Commitment (RUC):** Following the day-ahead market, ISO runs the *Residual* Unit Commitment "market". If submitted schedules (final schedules clearing the day-ahead market) do not fully reflect ISO load forecast, ISO may commit additional units to ensure	**Day-ahead Unit Commitment Service (UCS)**; allowing submission of 3-part bids (cost-based or 6-month fixed start-up and minimum-load; bid-based energy), along with technical and inter-temporal constraints (start-up time, minimum run time, minimum down time, all	RTO to provide Unit Commitment service allowing submission of multi-part energy bids, star-up, and minimum loads, and various operating constraints in conjunction with integrated Energy/Congestion Management market.

	CAISO CURRENT	CAISO PROPOSED (10/1/02)	CAISO PROPOSED (long-term)	FERC STANDARD MARKET DESIGN
		commit additional units to ensure adequate capacity on-line. Designated ACAP resources are required to be available for unit commitment. Resources committed by the CAISO will be guaranteed recovery of appropriate start-up and minimum load cost, using a net-of-market-revenues approach. Imports may compete with internal (or external) resources in the RUC. Competitive imports selected in RUC will be pre-dispatched for the real-time market operation; they will not be allowed to set the real-time price, but will be paid the bid price based on which they were selected in the RUC. To limit the impact of RUC import pre-dispatch on the real-time market operation, commitment to import energy in RUC will be limited such that the total supply clearing the day-ahead market plus the resource-specific minimum load and the RUC import energy do not exceed 95% of ISO's load forecast.	based on technical parameters filed with the ISO). Resources committed by the CAISO (not self scheduled for any hour of the day-ahead market) will be guaranteed recovery of relevant start-up and minimum load cost, using a net-of-market-revenues approach. **Residual Unit Commitment (RUC):** Following the day-ahead market, ISO runs the *Residual* Unit Commitment "market". If submitted schedules (final schedules clearing the day-ahead market) do not fully reflect ISO load forecast, ISO may commit additional units to ensure adequate capacity on-line. Designated ACAP resources are required to be available for unit commitment. Resources committed by the CAISO will be guaranteed recovery of appropriate start-up and minimum load cost, using a net-of-market-revenues approach.	Management market.
Release of Un-used Transmission Capacity after Close of DA Markets	None (all transmission allocated in congestion management is firm)	None (all transmission allocated in congestion management is firm)	Recallable Transmission Service: Following allocation of firm transmission in CM, ISO is considering performing recallable transmission service (RTS) allocation using unscheduled ETC capacity.[11]	Transmission capacity sold in DA that is not used by DA purchaser in RT should be made available for FT energy market
Hour Ahead				

[11] Preferred option is for ETC holders to agree to ISO scheduling time line (i.e., ETC rights expire after DA, like FTRs).

	CAISO CURRENT	CAISO PROPOSED (10/1/02)	CAISO PROPOSED (long-term)	FERC STANDARD MARKET DESIGN
Timing	2- hours before operating hour; Provides opportunity for schedule changes and incremental procurement of A/S. See Day-Ahead section for more detail on mechanics.		Considering moving closer to real-time [Considering simplification, and possibly making it advisory in the future when ISO implements a day-ahead unit commitment service with 3-part bids (for start-up, no-load/min-load, and energy)]	
Energy Market	None	None	See DA	
Congestion Management Market	See Day-Ahead	See DA	See DA	
Ancillary Services Market	See Day-Ahead	See DA	See DA	
Real Time				
Model spatial granularity	Zonal	Existing three-zone model	Full network model (3000 busses + external loops)	Nodal
Model objective function	Least cost to meet system imbalance, using merit-order bid stack. Performed zonally if major internal interfaces are congested. (splitting real-time bid stack in case of real-time inter-zonal congestion on internal control area transmission; no splitting of the real-time stack at the ties). Dispatch for intra-zonal congestion and local reliability is taken our of merit order and does not affect imbalance energy price.	Economic Dispatch (including clearing of overlapping inc and dec bids in every 10 minute interval). Performed zonally if major internal interfaces are congested.	Security-constrained economic dispatch (SCED), which accounts for all transmission constraints, loop flows, and generator performance parameters and constraints, and imbalance needs [plan to use State Estimator (SE) results as input to SCED if/when SE is implemented]	Security-constrained Economic Dispatch
Energy/CM Market bids	inc/dec bids	inc/dec bids	inc/dec bids	Inc/dec bids

	CAISO CURRENT	CAISO PROPOSED (10/1/02)	CAISO PROPOSED (long-term)	FERC STANDARD MARKET DESIGN
Ancillary Services bids	Out-of-Market Transaction if bids are insufficient	Out-of-Market Transaction if bids are insufficient	Nothing specific [considering real-time purchase of A/S if the hour-ahead market is made advisory]	Nothing Specific about A/S procurement in real-time
Market Power Mitigation	Per FERC 6/19 order: cost-based bids (with uniform market clearing pricing) in declared emergencies (reserve shortage); "soft" market-clearing price caps in non-emergency hours. No bid mitigation for locational needs.	Mitigation against economic withholding (pre-dispatch AMP) and local market power in real time [see market power mitigation below]	Mitigation against economic withholding (pre-dispatch AMP) and local market power in real time [see market power mitigation below]	(see market power mitigation section below)
Dispatch interval	Every 10 minutes	Every 10 minutes	Every 10 minutes	Every 5 minutes
Imbalance Price	Separate INC and DEC prices each 10 minutes for entire system, or for each zone if there is congestion.	Single 10-minute Real-time Price in each zone reflects redispatch costs for imbalance needs taking into account inter-zonal congestion.	Single 10-minute Real-time Price at each location reflects redispatch costs for congestion, loop flow, and imbalance needs.	Each locational price reflects redispatch costs for congestion, loop flow, & imbalance needs; Difference between 2 locational prices reflect costs of congestion and losses.
Penalties	Difference between INC and DEC prices creates incentive to follow dispatch instruction.	System of penalties for uninstructed deviation. [slightly modified from Amendment 42 filing]	System of penalties for uninstructed deviation.	Considers 3 options: No Penalty Penalty for uninstructed generation & load for reliability threat only Penalty for uninstructed generation & load
Post Real-Time				
<u>Settlement</u> **Stages**	3-stage settlement: DA, HA, RT .	3-stage settlement: DA, HA, RT. RUC compensation based on unrecovered start-up and min-load; real-time zonal prices for both load and generation.	3-stage settlement: DA, HA, RT[possible simplification in the future to make hour-ahead market advisory; leading to a 2-settlement system]. RUC compensation based on unrecovered start-up and min-load; real-time zonal prices for both load and generation.	2-stage settlement recommended: DA and RT

	CAISO CURRENT	CAISO PROPOSED (10/1/02)	CAISO PROPOSED (long-term)	FERC STANDARD MARKET DESIGN
Pricing/Payment: **Spatial Granularity**	System-wide or by zone when there is congestion between ISO zones.	System-wide or by zone when there is congestion between ISO zones.	Generators will earn nodal prices; loads may pay average LPA prices.	Nodal
Temporal Granularity	Hourly in Forward Markets (CM/AS) Every 10-minutes in Real-time (Energy)	Hourly in Forward Markets (CM/AS) Every 10-minutes in Real-time (Energy)	Hourly in forward markets (Energy/CM/AS); Every 10-minutes in Real-time (Energy; possibly also residual CM and AS under consideration)	Hourly for both pricing and settlement in forward market; sub-hourly pricing in RT with hourly settlement
Bid Caps	Per FERC 6/19 order soft cap– see above	Damage control bid cap in ISO energy and ancillary services markets is equal to $108/MWh (hard cap), and may be increased (but not decreased) in response to gas price movements, in accordance with FERC December 19, 2001 Order.	Damage control bid cap in ISO energy and ancillary services markets is equal to $108/MWh (hard cap), and may be increased (but not decreased) in response to gas price movements, in accordance with FERC December 19, 2001 Order. As market conditions improve it is anticipated that the level of the DCBC can be increased.	Damage control bid caps
DEMAND RESPONSE PARTICIPATION	Loads can participate in the Non-spinning Reserve and Supplemental Energy markets through Participating Load Program.	Loads can participate in the Non-spinning Reserve, Residual Unit Commitment and Supplemental Energy markets through Participating Load Program.	Adds capability for load to participate in the day-ahead and hour ahead energy markets; load will be allowed to submit three-part market-based bid blocks (minimum curtailment duration); also demand response can fulfill ACAP obligation. Demand response designated ACAP can participate in Residual Unit Commitment.	"Demand resources … should be able to participate fully in energy, ancillary services and capacity markets" "Market rules … must not unduly bias the choice between demand or supply resources" "Demand can best respond by participation in the day-ahead market" "Sellers (including demand side) must have the option of submitting multi-part bids"
MARKET POWER MITIGATION		To mitigate physical withholding: • Must Offer Obligation • RUC • Penalties for uninstructed deviations (not following	To mitigate physical withholding: • ACAP • Must Offer Obligation • RUC	Structural Solutions preferred. Behavioral rules for locational market power

	CAISO CURRENT	CAISO PROPOSED (10/1/02)	CAISO PROPOSED (long-term)	FERC STANDARD MARKET DESIGN
		dispatch instructions is s form of physical withholding) To mitigate economic withholding: • Resource specific bid caps for locational market power mitigation • Damage control bid/price cap • Automated Mitigation Procedure (action & impact thresholds similar to the NYISO AMP) applied to the real time market • Just & Reasonableness Price Index Mitigation Trigger: 12-month rolling average price cost markup threshold that if exceed will trigger additional system-wide bid mitigation measures To mitigate local market power: • Limit generation schedule out of constrained areas in the forward market • Mitigate out-of-merit Order INC bids needed for locational requirements in real-time • Mitigate out-of-merit Order DEC bids needed for locational requirements in real-time	• Penalties for uninstructed deviations (not following dispatch instructions is s form of physical withholding) To mitigate economic withholding: • Resource specific bid caps for locational market power mitigation • Damage control bid/price cap • Automated Mitigation Procedure (action & impact thresholds similar to the NYISO AMP) applied to day ahead, hour ahead and real time markets • Just & Reasonableness Price Index Mitigation Trigger: 12-month rolling average price cost markup threshold that if exceed will trigger additional system-wide bid mitigation measures To mitigate local market power: • Mitigate out-of-merit Order INC bids needed for locational requirements in the forward market and in real-time • Mitigate out-of-merit Order DEC bids needed for locational requirements in the forward markets and in real-time	Bid cap as a proxy for demand bidding Transmission provider to identify generating units that must run for reliability and have them subjected to mitigation Limitations on flexibility to change bids

3 The Market Design 2002 Project

The ISO initiated the Market Design 2002 (MD02) project in October 2001, and assigned the primary design effort to an inter-departmental team of ISO staff referred to in this document as the MD02 team. The present draft represents the recommendations of the MD02 team, based on the team's own design efforts, direction from ISO management, and the substantial comments and suggestions offered by participants in two series of stakeholder forums the ISO hosted in January and March. The remainder of this section frames the MD02 design effort by providing the mission statement, scope, deliverables and timing, guiding principles, and design objectives.

3.1 Mission Statement

The mission of the MD02 Project is to develop, obtain Board approval for, and file at FERC a program of ISO market design changes needed to ensure the ISO's effective and sustainable performance of its core functions, position the ISO to better serve the needs of all of its diverse customers, and support efficient performance of the electricity markets for the benefit of all California consumers.

3.2 Scope

To accomplish the stated mission, the program of market design changes developed by the MD02 project will:

- address the underlying deficiencies that led to the 2000-2001 electricity crisis, to the extent these deficiencies can be mitigated by ISO market design changes;
- correct the major design flaws in the ISO markets, some of which were identified well before the crisis began;
- provide a menu of services that better meet the demands of the ISO's diverse group of customers and market participants (including municipal and other vertically integrated utilities that utilize ISO-controlled facilities and ISO markets);
- be feasible to implement prior to Summer 2003;
- provide necessary features to ensure stable market performance and system operation when the FERC June 19 Mitigation Order expires on September 30, 2002;
- fulfill the ISO's commitment to FERC to file a permanent solution to intra-zonal congestion problems to replace the interim solution recently filed with FERC as a component of Amendment 42;
- be compatible with the designs being developed by RTOs in the western region and address other seams issues as necessary to ensure, to the greatest extent possible, a seamless energy market in the West.

3.3 Proposed Deliverables and Timing of the MD02 Project

There are a few key considerations and constraints that influence the content and timing of the MD02 project's major deliverables. These factors are:

- FERC's December 19, 2001 Order on Clarification and Rehearing directs the ISO "to file by May 1, 2002 its revised congestion management proposal and a plan for implementation of a day-ahead market."
- FERC's June 19, 2001 Market Mitigation Order expires on September 30, 2002.[12] By that time the ISO must have substitute mechanisms in place to, as far as possible, provide for stable market performance and reliable system operation.
- Significant changes to the real-time market will be made in implementing the Real Time Market Pricing proposal (i.e., the permanent "Target Price" resolution), included as part of the October 1st Elements Tariff filing. The proposal is to implement an economic dispatch algorithm to continuously clear overlapping real-time energy bids, subject to transmission and generator ramping constraints. As a result there will be a single price in each 10-minute interval and a new set of incentives to comply with dispatch instructions. In implementing these changes the ISO will install economic dispatch software, and thus these changes represent a first stage of implementation of real-time security constrained economic dispatch, which is a key design element of this proposal.

To accomplish its mission the MD02 project is structured to produce four deliverables.

1. The first deliverable is the package of October 1st Elements, which the ISO proposes to implement by September 30, 2002, when the existing market mitigation rules expire. ISO management discussed this package with the ISO Board of Governors at their March 14 meeting, and issued a revised package for public review and comment on March 29. At the April 9 Board meeting the Board conceptually approved this package.
2. The second deliverable, which the present document represents, is a "Comprehensive Design Proposal" that identifies the full set of problems to be addressed and describes the entire program of long-term market changes necessary to address those problems. The word "comprehensive" refers to the scope of the proposal, not to the implementation language for the ISO tariff, hence this document does not include draft tariff language at this time. At the April 25 Board meeting the Board approved the filing of this proposal.
3. The third deliverable will be a FERC filing that includes tariff language for the October 1st Elements and the narrative form of the Comprehensive Design (i.e., the present document). This tariff filing will be developed based on the guidance provided by the Board at the April 9 and 25 meetings, and will be filed on May 1 in compliance with FERC's December 19 Order.
4. The fourth deliverable will be a FERC filing that includes the tariff language for the Comprehensive Design. The ISO expects to make this filing on or about June 15, 2002.

3.4 Guiding Principles

The initial effort of the MD02 team produced the following principles to guide the development of specific design proposals.

[12] On December 19, 2001 FERC issued an Order denying the ISO's motion for rehearing of the September 30 expiration date. We had argued that the date was arbitrary and that to remove mitigation without a determination that the ISO markets were no longer subject to manipulation through the exercise of market power was an abrogation of FERC's responsibilities under the Federal Power Act to ensure just and reasonable rates. With FERC's denial of the ISO's motion, the only remaining recourse to seek reversal of this decision is through judicial review, which ISO Management initiated on February 14 in a petition submitted to the U.S. Court of Appeals for the Ninth Circuit.

1. Improve upon the ISO's performance of its core functions (non-discriminatory transmission service, reliable operation, congestion management, ancillary services, real-time balancing, transparency, timely market information, etc.).
2. Draw upon viable proposals and principles that have been developed or identified through previous ISO and stakeholder efforts, and upon the ISO's experience accumulated over nearly four years of operating its markets and the grid. For example, the January 2001 CMR Proposal and the April 2001 Market Stabilization Plan will both be revisited for the design effort, but will not limit the consideration of other options.
3. Develop a clear understanding of the root causes of problems, and solve problems at that level.
4. Design from ideal viewpoint at first – what is the best design to achieve the objectives – then consider impact of system constraints and other factors that must be accommodated. One implication of this principle is that there are no aspects of today's markets that we are accepting as compulsory design features.
5. Design for flexibility so that the market design and the underlying systems are adaptable and can be easily changed to reflect changed circumstances (e.g., changes resulting from FERC's Standard Market Design proceeding, changes necessary as a result of evolving western RTO development, and principles of open architecture).
6. Strive for the creation for seamless western market by considering and addressing seams issues.
7. Appropriately prioritize and stage FERC filings and implementation efforts to enable the ISO to implement the necessary market design features by the time the current FERC-established price mitigation measures expire.
8. Strive for simplicity and transparency.
9. (From January 2001 CMR Proposal) Recognizing that reliable real-time operation of the grid is fundamental to the ISO's core function of providing reliable transmission service to support a competitive electricity market, the ISO's proposed market design changes must be consistent with and must support real-time operating needs ("the consistency principle").

3.5 Design Objectives

The MD02 team identified the following design objectives as a way to translate the mission statement, scope and guiding principles above into more focused, specific ISO market design issues that need to be addressed in a comprehensive market design proposal.

3.5.1 Overall

1. Enhance the ISO markets to be a more attractive place for all participants to do business.
2. Provide adequate, timely, and transparent information, tools and incentives for market participants to self-manage their business activities and risks in the forward markets (i.e., offer a "toolbox" of services).
3. Accommodate, to the greatest extent possible, the special circumstances and needs of municipals and other vertically integrated utilities that use ISO systems or markets.
4. Improve operational control of the ISO-controlled grid.

3.5.2 Real Time Market

5. Minimize volume so that real time is a balancing market only. (NOTE: This may be less of a concern than it is today as the ISO implements a Capacity Obligation and Day-ahead Residual Unit Commitment as discussed below.)
6. Attract adequate supply bids for competitive real-time prices (including increased participation of imports and demand response).
7. Ensure reliable, predictable and adequate performance by generating resources (i.e., maximize incentives to comply with dispatch instructions so that real-time market provides effective load following, with minimal need to rely on Regulation to do load following).
8. Provide price transparency.
9. Provide dispatch transparency – procedures are clear to market participants, are followed consistently by ISO, and are consistent with price signals (see #8).
10. Ensure ISO dispatch instructions are responsive to all system and resource constraints, i.e., realistic.
11. Mitigate locational market power.
12. Provide operational simplicity, to minimize burden on real-time operations.
13. Improve ability to maintain Operating Reserves (O/R) within the hour.
14. Ensure inter-control area compatibility.

3.5.3 Forward Markets (Day Ahead, Hour Ahead)

15. Ensure adequate capacity is available to meet RT needs.
16. Ensure final schedules are feasible (i.e., satisfy inter-zonal, intra-zonal and ramping constraints).
17. Ensure final schedules are “operable” – scheduled quantities and locations reflect expected reality, i.e., final schedules should be “close” to their real-time profile and adequate supply should be available with proper locational dispersion to meet ISO’s forecast load. (This may be less of a concern with a Capacity Obligation and Forward Unit Commitment.)
18. Maximize availability and efficient use of transmission capacity.
19. Mitigate both system-wide and locational market power.
20. Satisfy local reliability needs efficiently.

4 Context and Assumptions Underlying This Proposal

4.1 Terminology: the Components of Electric Service

For purposes of this discussion we identify the major structural and functional components of the provision of electric service as follows.[13] Prior to electric restructuring these components were all performed by a single corporate entity, the traditional vertically-integrated utility (VIU), which could be either investor-owned or publicly owned. Under electric restructuring, these components may all be performed by different entities, in some instances under competitive market structures and in other instances under regulated monopoly structures. As a starting point, the transmission and distribution functions were considered regulated monopoly activities, while generation and the wholesale and retail supply functions were considered areas where competition would yield significant efficiencies and should therefore be facilitated.

Generation – the production of electricity through the conversion of a primary energy resource (such as fossil fuel, wind, geothermal steam, flowing water, sunlight, nuclear energy).

Transmission – the transportation of electricity at high voltages. (This may include delivery of electricity to certain end-use consumers who take service at these high voltages.) In California and other restructured jurisdictions, the transmission component is further subdivided into the ownership and maintenance of the transmission network (by the transmission owner or TO) and the real-time operation of that system (by the system operator). The very important function of building new transmission facilities and upgrades is still a matter for policy resolution.

Distribution – the transportation and delivery of electricity from the transmission system to the premises of end-use consumers. Included in this function is the stepping-down of voltage from transmission level (typically in the range of 60 to 500 kilo-Volts or kV), to end-use consumption level (typically 110 Volts for households). The entities that perform this function are called "utility distribution companies" (UDCs) and, for the purposes of this proposal, may be either investor-owned or publicly-owned.

The generation, transmission and distribution components (plus the supply of primary energy resources to be converted to electricity, which is not per se a component of electric service and therefore is not a subject of this proposal) are the *physical components of electricity supply*. In addition there are several *commercial components*, which do not require the performing entity to own or operate any of the physical components directly:

Wholesale supply (power marketing) – the purchase of electricity from generators or other wholesalers for resale to buyers who are primarily not the end-use consumers; also, the operation of markets and exchanges to facilitate trades between wholesale sellers and buyers.[14]

Retail supply – the provision of electric service to end-use or retail consumers. In this proposal the providers of retail electric service will also be referred to as "load-serving entities" (LSEs). To perform this function the LSE must obtain wholesale energy supply from generators and/or marketers, and procure transmission and distribution services to transport the energy from the

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[13] In this document, hopefully without confusion, we will use these primary component terms to denote functional activities or sectors of the industry (e.g., "the generation sector"), the physical facilities used to perform the functions (e.g., "generating plants"), and the corporate entities that perform the functions (e.g., "the generators").

[14] We recognize the important distinction between whether or not an entity operating at the wholesale level actually takes title to wholesale power, versus simply acting as a broker to facilitate trading between buyers and sellers together. For the purposes of this proposal, however, it is sufficient to encompass both types of activity within the wholesale supply component without distinguishing them.

generation sources and deliver it to end-use consumers. In addition the retail supplier must perform or otherwise ensure accurate performance of the retail business functions of metering, billing and revenue collection.

Finally, there are certain crucial *regulatory functions* whose precise design depends on the organization of the industry, the nature and extent of market versus regulated activities, and the nature of the entities performing the various physical and commercial functions identified above. The following discussion begins by identifying certain key assumptions about the structure of California's electricity industry and the nature of the entities involved.

4.2 Basic Elements of California Restructuring

This proposal assumes that California's electricity industry will retain certain key assumptions of, and basic structural elements established by AB 1890 and FERC Order 888. Specifically:

1. The electricity transportation system within California which serves California's electricity consumers will consist of a FERC-regulated transmission system and a state-regulated distribution system.
2. California will continue to have a mix of investor-owned utilities (IOUs) and publicly-owned utilities (municipals, irrigation districts, other governmental entities, etc.). At a minimum these entities will operate electric distribution systems whose service territories collectively comprise all of California's retail (i.e., end-use) consumers. In addition these entities may own and/or operate generation and transmission facilities, may participate in wholesale marketing, and may supply electricity to retail end-use consumers in their distribution service territories.
3. Some portion of the generation resources within California will be owned by entities that are not utilities in the previous sense, i.e., do not have distribution service territories. Resources in this category will therefore not inherently be dedicated to any particular service territory. Rather, they will operate under market-based rates rather than cost-of-service regulated rates, and will be free to sell their output into markets or to buyers of their choosing both within and outside of California. In this regard, crucial objectives of California's electric industry restructuring are to attract private investment in generation to serve California consumers, and to facilitate competition among generation suppliers.
4. California will have an Independent System Operator (ISO) whose core functions include the following:
    - Reliably operate the transmission system that comprises its control area, which includes the transmission facilities owned by the IOUs as well as facilities owned by any of the publicly-owned utilities that become "participating" transmission owners. We assume that, for the foreseeable future, some transmission facilities within the state will not be under ISO control.
    - Facilitate and ensure non-discriminatory access to the transmission system under its control, through appropriate policies and procedures for scheduling, congestion management, allocation of transmission rights, etc.
    - Procure the generation services needed for reliable operation (e.g., operating reserves and real-time balancing energy) in an efficient and cost-effective manner.
    - Provide adequate and timely information to all users of the ISO-controlled grid as needed to facilitate self-management of essential electricity supply activities by those users and to simplify their interactions with the ISO, as far as is practical.

4.3 Long-term Conditions

In addition to the structural aspects identified above, this proposal assumes that the following conditions will exist in the long term. These conditions are the underlying requirements for this proposal to be fully realized and its elements to be fully effective.

5. All entities responsible for performing the functions identified above will be creditworthy and fully capable of performing their designated functions.
6. In particular, all LSEs will be creditworthy buyers, and the state-regulated LSEs will have clear and workable rules regarding supply procurement and cost recovery.
7. State policy makers and appropriate agencies will have defined and implemented an effective state role in ensuring supply adequacy for California's consumers.
8. Settlement of ISO-related transactions will be reliable and timely, so that the business risks of transacting with the ISO will be reduced to a normal and sustainable level.
9. California will continue to rely on imported energy to meet a significant portion of in-state demand at certain times, and will have excess energy to sell out-of-state at other times. In this regard, crucial objectives of the industry structure are to facilitate operational coordination and trading of energy and reserve capacity between California and other control areas in the western region, as well as between the ISO control area and any non-ISO-members within the state.
10. Retail supply within each distribution utility's service territory may be performed in any of the following manners: (1) pure monopoly – retail supply is a monopoly service of the distribution utility itself; (2) pure "direct access" – retail supply is performed completely by non-utility retail suppliers (called "electric service providers" or ESPs), including perhaps a supplier affiliated with the distribution utility but separated by formal operational and legal firewalls; (3) in between options (1) and (2), the distribution utility retains a share of the retail load alongside non-utility ESPs. Under model (3) the utility may or may not have a "default service" obligation whereby it must serve all consumers who do not elect a non-utility ESP. The current proposal is intended to be compatible with any of these options for retail supply.

4.4 Near-term Conditions

Recognizing that the requirements of the long-term design may take some time to realize, the second objective of the present proposal is to identify mechanisms to promote stable market performance and grid operation in the interim, specifically beginning with the expiration on September 30, 2002, of the FERC-ordered mitigation mechanisms that currently exist. The specific near-term conditions we assume will exist at that time are:

11. At least one of the IOUs operating as a LSE in California will not be creditworthy, and hence will not be able to fully meet its supply obligations without additional state support because it (a) does not own enough generation to serve its native load, and (b) does not meet the Commission's standards to be able to purchase energy in the ISO markets.
12. The procurement and cost recovery rules for IOUs that serve California load may not be finalized by the California Public Utilities Commission (CPUC), thus contributing an uncertainty that may prevent the IOUs from procuring power in the forward markets.
13. The California Energy Resource Scheduler (CERS) will be responsible for filling the supply gap that can not be covered by non-creditworthy IOUs using their own generation, at least for the period through December 31, 2002. There are two crucial

aspects to CERS's role: direct procurement and scheduling of supply resources to meet net IOU load, and financial backing of supplies procured through the ISO markets (i.e., real-time balancing energy, ancillary services and residual unit commitment).

14. Prior to January 1, 2003 the state will need to either extend CERS's existing roles or identify and authorize another entity to continue to fill these roles until all LSEs who utilize the ISO control area and the ISO markets are fully creditworthy and functional. Unless there is another designated creditworthy backer of necessary ISO transactions, the ISO will not be able to fulfill its core functions since it relies on the creditworthiness of the entities that purchase through its markets.
15. The state-procured power supply contracts currently scheduled by CERS will continue to provide a significant share of the supply needed to meet IOU load. If the state succeeds in its petition to overturn these contracts and actually does decide to void them, the state or the IOUs will need to devise another means to obtain the required supply. The ISO does not believe that it is feasible to procure such supply volumes through the ISO spot markets at reasonable prices and without jeopardizing reliable operation.
16. Some of the factors originally identified as root causes of the California electricity crisis will not be fully remedied by October 2002. In particular: (a) there may still be shortages of generation supply at certain times, giving rise to supplier market power in the ISO control area; (b) there will still be significant transmission constraints that limit competitiveness of supply in certain portions of the ISO control area at certain times; (c) there will still be limited demand responsiveness, which exacerbates the problem of supplier market power; and (d) some of the market design changes proposed by the ISO can not be implemented until spring of 2003 at the earliest, including the reform of congestion management and the creation of a day-ahead energy market.15
17. At the same time, some improvement regarding the root causes will be achieved, particularly the volume of forward contracting and commensurate reduction in reliance on spot markets. Note, however, the potential complication of overturning the existing state supply contracts currently scheduled by CERS, as mentioned above.

[15] Readers should refer to the ISO's Third Quarterly Report on Market Conditions, filed with FERC on March 26, 2002, for additional information regarding near-term market conditions.

5 Elements of the Proposed Comprehensive Design

The proposed Comprehensive Market Design is comprised of the following elements, each of which is discussed in detail in this section:

1. Available Capacity Obligation on Load Serving Entities
2. Forward Congestion Management and Forward Energy Market
3. Firm Transmission Rights
4. Ancillary Services Markets
5. Residual Day Ahead Unit Commitment
6. Structure and Timing of Hour Ahead and Real Time Markets
7. Real-time Economic Dispatch Using Full Network Model
8. Demand Scheduling, Bidding and Settlement
9. Bid Mitigation for Local Reliability Needs
10. Damage Control Bid Cap on ISO Markets
11. Bid Screens and Mitigation
12. 12-month Market Competitiveness Index and Pre-authorized Additional Mitigation Provisions
13. Penalties for Excessive Uninstructed Deviations.

Item 1 addresses a fundamental flaw in California's original electric restructuring design, namely, the absence of a well-defined responsibility on load serving entities to ensure that adequate supply resources are procured to serve their expected loads and meet reserve requirements.

Items 2 through 5 represent the central design changes to the ISO's market structure: the creation of a forward congestion management procedure integrated with an energy market, ancillary service procurement, and transmission-constrained unit commitment market, based on a full network model and locational marginal pricing at the nodal level. The adoption of such a structure then requires redesign of the transmission rights instrument. Finally, a residual unit commitment procedure for reliability purposes completes the new day ahead structure.

Item 6 involves some simplifications possible in the hour ahead and real time markets as a result of the new day ahead structure, while item 7 applies the same full network model that is used in the forward markets as the basis for real time economic dispatch. Item 8 discusses the geographic granularity of demand scheduling, bidding and settlement and the participation of loads in the ISO markets.

Items 9 through 13 address market power monitoring and mitigation both at the local level and the system-wide level.

5.1 Available Capacity (ACAP) Obligation on Load Serving Entities

5.1.1 Introduction

Since the beginning of the Market Design 2002 (MD02) effort, the ISO has identified, as an integral part of MD02 effort, the need to establish an Available Capacity (ACAP) obligation on Load Serving Entities (LSEs)[16], as represented by their Scheduling Coordinator (SC), in California. As stated by the ISO in its April 3 Draft Comprehensive Design Proposal, the ACAP Obligation is necessary to support the ISO's core function – that of providing non-discriminatory and reliable transmission service to all customers. In addition, the ISO's ACAP obligation is consistent with the ISO's obligations under Assembly Bill No. 1890 (AB 1890). In that regard, AB 1890 required the ISO to ensure efficient use and reliable operation of the transmission grid consistent with the achievement of planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council (WSCC).

Specifically, as proposed, the ACAP Obligation will support reliable system operations by requiring LSEs to procure, in a forward-market timeframe, resources sufficient to satisfy the ISO's peak daily operating requirements. Moreover, by requiring that such ACAP resources are made available to the ISO in the day-ahead market, the ISO can satisfy its objective to move operating decisions from real time into the forward market – further in support of reliable operations. As stated in the April 3 Draft Comprehensive Proposal, an ACAP Obligation will also provide ancillary benefits to the market by creating a platform for forward-contracting and generation investment, thereby stabilizing spot-market energy prices. The ISO continues to believe that its proposed ACAP Obligation, as modified below, is reasonable, necessary, and consistent with the ISO's limited role in the market – that of ensuring reliable and non-discriminatory transmission service.

Over the past several months, market participants, other stakeholders and state agencies have raised a number of issues regarding the ISO's ACAP proposal. These parties have questioned the need for, and details of, the ISO's proposal. Specifically, as described further below, a number of parties have questioned the need for ACAP in light of the California Public Utilities Commission's (CPUC) commitment to specify procurement rules for the states' Investor-Owned Utilities (IOUs). Moreover, parties have questioned the ISO's proposal to move ahead with a near-term ACAP proposal in light of the uncertainty surrounding the IOUs financial status and the role of the state in procuring power to serve the IOUs' net-short position. Finally, among other issues, a number of market participants raised concerns that the ISO's proposal will unnecessarily raise costs to consumers, especially those located within constrained regions of the ISO control area.

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[16] The term "load-serving entity" or LSE refers to any entity that provides electric energy to end-use consumers. While there are some non-utility electric service providers (ESPs) that serve end-use consumers under the direct access provisions of the California restructuring, the largest LSEs in California are the three Investor Owned Utilities (IOUs). The three IOUs, in combination with five Governmental Entities, make up the Utility Distribution Companies (UDCs) in the ISO's structure. The UDCs are the distribution system operators in their respective Service Areas as well as the default electric service providers for consumers who have not chosen a non-UDC direct access provider. The proposed ACAP obligation would of course apply to all LSEs. Moreover, since the ISO transacts directly only with Scheduling Coordinators (SCs), the ACAP obligation would be applied through the SCs who schedule for LSEs.

The ISO has carefully and thoroughly considered these comments. Based on this feedback, the ISO has concluded that:

1) An ACAP Obligation, appropriately tailored and structured to support ISO operations, is a necessary element of the ISO's long-term market design. That is, consistent with the ACAP proposal outlined in the April 3 Draft Comprehensive Design Proposal, the ISO's ACAP Obligation should be based on the minimum requirements necessary to support reliable transmission system operation;

2) The timeframe for implementing an ACAP Obligation should be sufficient to allow for:

    a. Enhanced coordination between the ISO, LSEs and affected state agencies to allow for the thorough development of the ACAP proposal. The ISO believes that such coordination will ensure better alignment between the procurement rules established by the CPUC and the obligations established by the ISO. In addition, such communications will facilitate better coordination between the CEC and the ISO with regard to the collection and assessment of information regarding California's long-term resource adequacy. Finally, as noted in the April 3 Draft Comprehensive Proposal, development of the ACAP proposal will necessitate the transfer, collection, assessment and use of new information and the new tools necessary to process such information. These efforts will require close coordination between the ISO and all LSEs. In the end, it is the express intent of the ISO to not duplicate or assume any of the functions or responsibilities already performed by other entities in California.

    b. Development of an integrated proposal that systematically and consistently addresses the ISO's ACAP, Reliability Must-Run Generation (RMR) and transmission planning requirements and objectives. The ISO believes that all of these areas must be coordinated so as to further the ISO's long-term objective to develop a reliable and robust transmission system capable of supporting a stable and competitive electricity market.

    c. In close coordination with achieving (b) above, minimizing the exposure of load to market power and permitting the development of appropriate market power mitigation measures.

Thus, the ISO's final ACAP proposal, as outlined herein, reflects the above considerations. In order to ensure that a fully effective ACAP proposal can be implemented within a reasonable timeframe, the ISO proposes to do the following:

1) Finalize, and include as part of its May 1, 2002, Comprehensive Design Proposal to FERC, the conceptual framework for an ACAP Obligation on LSEs;

2) In the period subsequent to May 1, 2002, continue to work will all market participants to develop the details of an ACAP proposal; a proposal that recognizes, and is aligned with, the requirements and functions of other entities within the state. The ISO would aim to file such a detailed proposal on June 15, 2002;

3) The ISO is *not* proposing to implement a "Transitional ACAP" on October 1, 2002. However, the ISO will, on a cooperative basis, begin to work with LSEs and exchange information in order to work towards full ACAP implementation.

The ISO believes that the ACAP Obligation proposal outlined below will enhance the ISO's ability to reliably operate the transmission system. Specifically, the ISO's ACAP proposal will ensure that LSEs have procured, on a monthly basis, the resources necessary to satisfy the

ISO's peak-load requirements for operating and regulation reserves. Moreover, the ISO's proposal will require ACAP suppliers to make their resources available to the ISO on a day-ahead basis for potential commitment in the ISO's day-ahead market – thus achieving a primary objective of the ISO's market design initiative, to move the majority of operating decisions from real-time into the forward market. Finally, the ISO believes that its proposal will further the efforts of both state and federal policymakers to ensure adequate forward contracting, reduced reliance on the spot market, and create a platform for generation and demand-side investment in the California market.

5.1.2 Background – Dimensions of the ACAP Design

The primary purpose of the ISO's proposed ACAP obligation is to ensure that adequate capacity is available to be committed on a daily basis to meet system load and the ISO's operating and regulation reserve requirements. Under California restructuring, as codified in AB1890, no entity was given the explicit responsibility for ensuring adequate capacity to serve IOU and ESP load, including the IOUs and ESPs. One result of this was that the ISO frequently faced supply shortages right up to and including the operating hour. To remedy this defect in the original market design, the proposed ACAP obligation will apply to all LSEs, thus placing the responsibility to procure adequate capacity to meet expected peak monthly loads plus reserve requirements on the SCs for LSEs.

ACAP introduces a new element into the governance of the California power markets. The ISO, therefore, believes that implementation of the ACAP obligation will likely require a phased approach.

Three principles underlie the development of this ACAP proposal:

1) The ACAP obligation is intended to enhance system reliability and security by providing the operator with adequate resources to enable a fully scheduled day-ahead unit commitment.
2) Customers should not incur additional costs for meeting ACAP obligations that do not enhance reliability; and
3) The ACAP obligation will not create market mechanisms that promote the abuse of market power.

The ACAP obligation requires LSEs to develop a portfolio of supply arrangements and demand management capabilities to meet their customers' needs. An ACAP requirement imposed without adequate lead time or recognition of existing contracts could place the LSEs at a severe disadvantage in negotiating with suppliers. The ISO has attempted to conform this proposal to satisfy the above identified criteria.

Finally, the ISO notes that the concept of a forward capacity market is not a new idea. In fact, such markets and obligations similar to that proposed by the ISO herein, are already in place in the eastern ISOs and in other markets around the world. Appendix B to this Comprehensive Design Proposal contains a detailed background summary of these other markets.

5.1.3 Summary of ACAP Proposal

The ISO proposes to require each LSE in the ISO Control Area to identify, on a month-ahead basis, the resources they will make available to serve their forecast load for a given month, plus a reasonable reserve margin. The ISO proposes to *base* such reserve requirements on the established Western Systems Coordinating Council (WSCC) Minimum Operating Reserve Criteria (MORC), but then translate those daily operating requirements into a monthly requirement. LSEs and the ACAP suppliers will then have an obligation to schedule or bid the ACAP capacity into the ISO's day-ahead market. LSEs and ACAP suppliers that fail to satisfy the ISO's monthly and daily requirements will face penalties; penalties set at level necessary to provide incentives for such entities to continually satisfy the ISO's operating requirements. The ISO thus believes that, through its ACAP proposal, system security will be enhanced because sufficient resources will have been committed to serve forecast load and satisfy the ISO's peak-load operating reserve requirements. Moreover, satisfaction of these requirements will allow the ISO's real-time market to become a true imbalance market; a market that adjusts for unforeseen outages or demand increases and whose purpose is not to serve large quantities of unscheduled demand.

As detailed further below, the ISO's proposal provides that each LSE's ACAP obligation will be calculated on a monthly basis as a fixed margin above the next month's forecast peak load. LSEs will be required to meet this obligation for all hours that have a significant probability of being the peak hour (most likely the three or four hours across the monthly peak). The obligation may be met by a combination of own generation, firm energy contracts (including contracts obtained by the State on behalf of consumers served by the IOUs), capacity contracts, and physical demand management (as opposed to financial arbitrage between the forward and real-time markets). Prior to the start of each month, the LSE will demonstrate to the ISO that it has secured adequate capacity for the coming month and will be required to identify the relevant "ACAP resources" and associated MW quantities.[17] The LSE will be assessed a penalty for any shortfall.

As the title "Available Capacity" suggests, the ACAP obligation differs from the "Installed Capacity" or ICAP obligation common to the eastern ISOs by virtue of the ACAP's availability requirement. This means that a resource designated as an ACAP resource by an LSE must be fully available to the ISO (for the amount of contracted capacity) via a combination of firm forward energy schedules, bids to participate in unit commitment, supply ancillary services and energy markets, and must respond to ISO dispatch instructions. In the event of a plant outage or derating other than planned maintenance, the supplier would be responsible for providing a substitute resource or paying for replacement energy, would be charged the ACAP shortfall penalty and, if the supplier does not report the outage to the ISO in a timely manner, would be assessed penalties for failing to follow dispatch instructions.

It is important to clarify that this does not necessarily mean that the supplier has to physically withhold another resource as back up or insurance against an outage. If the back-up resource is bid into the real-time market (BEEP stack), even if it is dispatched for imbalance energy, as long as the amount (MW) bid into the BEEP stack (at or below prevailing market-wide bid caps) equals or exceeds the (forced out) capacity of the ACAP resource, the real-time ACAP unavailability penalty would be waived. Moreover, the ISO's proposed real-time uninstructed deviation penalties would be waived if the outage information is provided to the ISO within 30 minutes. When the DEC instruction is issued to the forced out resource, there would be a charge equal to the MCP. However, if the bid in the BEEP stack from the back-up resource is below the MCP, the other resource would collect the MCP for at least the same amount of MW or more. This means the ACAP provider would not incur any additional cost than the alternative where the other resource had been kept on standby and started up only upon the forced outage of the ACAP resource. In fact, by bidding the other resource in the BEEP stack, the generation

[17] The ISO expects that LSEs would procure portions of their ACAP obligations on different time horizons, such as up to 90 percent on an annual basis, 5 percent seasonally, and 5 percent monthly. However, at least with respect to the IOUs, this matter is appropriately and best addressed in the CPUC's procurement rulemaking.

owner collects additional revenue as long as the ACAP resource is available (a much more profitable outcome for the generation owner than simply keeping the other unit on standby). If the real-time bid from the other unit reflects that unit's operating cost and is higher than the MCP, the generation owner should be satisfied with the ISO providing the replacement energy from a cheaper unit and charging the corresponding MCP.

In summary, the ISO will verify each LSE's compliance with the ACAP obligation on a monthly basis based on its demonstration of adequate contracts and designation of specific resources, and then will verify compliance for designated ACAP resources on a daily basis based on their availability.

5.1.3.1 Transitional Issues and Implementation Timeline

In order for the ISO's ACAP proposal to become fully effective, a number of conditions must be met and institutional mechanisms created. For example, before ACAP can be a fully effective tool Pacific Gas & Electric Company (PG&E) and Southern California Edison Company (Edison) must be returned to creditworthy status and be capable of procuring the necessary resources to satisfy the ACAP requirement. Moreover, before the ISO can realistically expect LSEs to enter into forward contracts to supply ACAP, those LSEs subject to the CPUC's jurisdiction will likely require assurances that such forward contracts will be deemed reasonable by the CPUC and that the CPUC will allow recovery of the contract costs through retail rates. Therefore, the ISO believes that it will be unable to fully implement ACAP until the CPUC has concluded its ongoing proceeding regarding the specification of procurement rules for CPUC-jurisdictional entities. The CPUC has stated that it expects to conclude this proceeding by October, 2002. Finally, the ISO's ACAP proposal contemplates the development of certain information-driven requirements and mechanisms. For example, as explained below, the ISO proposes to use an ISO Control Area forecast (broken down on a UDC basis) to determine and allocate the ACAP requirement for each LSE in the UDC Service Area. The ISO proposes to base such determination from the historical loads of these entities. The ISO has actual load data for the UDCs, but does not currently have or receive such information on a LSE basis. Therefore, as part of its proposal, the ISO proposes to develop and establish such a database.

These mechanisms will take time to develop and require close coordination with the UDCs and LSEs, as well as with affected state agencies. Based on these considerations, the ISO anticipates that its ACAP proposal may not be fully implemented until these mechanisms are in place. Nonetheless, the ISO believes that it is imperative that the ISO, market participants, and all affected regulatory agencies move forward now to establish the policy framework and institutions necessary to support the ACAP proposal. Subject to the constraints identified above (including creditworthiness) and in the next section, the ISO proposes to make the ACAP Obligation fully effective by January 2004.

5.1.4 The Inter-relationship Between ACAP, RMR and Transmission Planning

A number of market participants have raised concerns that the ISO has not adequately explained the interrelationship between the ACAP proposal, RMR and transmission planning. The ISO understands that a comprehensive approach is required in order to effectively and fairly address these issues. The ISO also understands and appreciates the fact that the incentives and requirements established in each of these subject areas impacts the ISO's ability to reliably operate the control area. Moreover, the ISO believes that appropriate and consistent incentives and cost-responsibilities should be established in all three venues in order to achieve the common objective – creation of a reliable and robust transmission system capable of supporting competitive market outcomes.

5.1.4.1 The Locational ACAP Requirement

The ISO proposed that the ACAP requirement be defined on a locational basis and determined in a manner that recognizes the major transmission constraints on the system. By so doing, the ISO is intending to maximize the availability of such resources and to prevent over-reliance on resources located in one part of the system to serve needs in other areas between which a transmission constraint might exist. This approach is consistent with the ISO's existing practice to procure RMR and ancillary services on a locational basis, appropriately recognizing transmission constraints and the ISO's ability to call on those resources to serve system or local needs. Moreover, a locational ACAP requirement is also consistent with the ISO's proposed approach to Residual Unit Commitment, which will once again factor in transmission constraints on the system when committing resources to serve forecast load. By recognizing operational reality (e.g., transmission constraints) in the design and structure of market rules and requirements, the ISO will further its efforts to ensure reliable system operation - a fundamental goal of the market redesign.

As provided in the April 3 Draft Comprehensive Proposal, the ISO proposed to define the locational ACAP requirements based on today's RMR areas, since the RMR areas by definition represent load pockets on the grid with limited import capability.[18] Thus, in RMR areas, load may be unable to rely on resources outside of the area to satisfy forecast requirements. Thus, the ISO believes there is an appropriate relationship – deliverability of resources – between RMR, ACAP and the ISO's general AS procurement practices. Finally, we believe that such an approach is consistent with the established practices of the eastern ISOs.

5.1.4.2 ACAP and RMR

The April 3 Draft Comprehensive Proposal also provided for a transition from the ISO-administered RMR process that exists today to an ACAP paradigm where LSEs within each LRA have an obligation to procure ACAP on a locational basis and thus contract with the local providers. In recognition of the local market power currently addressed through RMR, the ISO proposed an approximately two-year phase-out of RMR. During that transition period, the ISO stated that either the existing RMR contracts would be assigned to the LSEs, or, the LSEs, in conjunction with the ISO, will develop new cost-based ACAP contracts.

Market participants raised, among others, the following concerns with the ISO's RMR phase-out proposal: 1) that the ISO's proposal unfairly shifts RMR costs to local LSEs and that such treatment is inequitable in light of the previous decision by the transmission owners to not invest in transmission in those local areas; 2) that the ISO has failed to consider or explain how its proposal is related to transmission planning and the consideration of generation and demand-side substitutes for transmission and RMR; 3) the ISO did not fully consider the market power implications of its proposal and that the proposal exposes LSEs to local market power abuse;

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[18] It is important to note that the ACAP requirement (MW) and the RMR requirement (MWh) are different. The ACAP requirement will be defined by *capacity* requirements whereas the RMR requirements are local *energy* requirements. Therefore, the local ACAP requirement is likely to be higher than the RMR requirement that exists today. The consequence of this difference is that LSEs will most likely have to procure a portion of their local ACAP requirement from local providers (existing RMR) and a portion from outside the local area (secured, in part, through FTRs). In addition, for the period of time that RMR continues, the ISO proposes to reduce the local ACAP requirement in each LRA based on the RMR capabilities in the area.

and 4) since these local areas are by definition transmission constrained, the ISO's proposal to permit the use of FTRs to ensure delivery of resources outside the area is of limited value, since there likely will be insufficient FTRs into the area.

The ISO agrees that its ACAP proposal must be coordinated and integrated with the treatment of RMR and transmission planning. Moreover, as stated in the April 3 Draft Comprehensive Proposal, the ISO agrees that the imposition of the ACAP requirement should not transfer market power from one market to another and should not result in increased costs to load with no benefit. In consideration of the concerns expressed above, the ISO offers the following observations and modifications to its draft proposal.

5.1.4.3 Transmission Planning

First, the ISO has always believed that a proactive transmission planning process is an essential element of any long-term market design and the ISO believes that it is necessary for the ISO to proactively identify and address, if appropriate, transmission constraints on the system. As many market participants are aware, the ISO has recently sponsored testimony before the CPUC on the "economic" need for a Path 15 upgrade. As explained in the ISO's testimony, a primary driver for the ISO in recommending that Path 15 be expanded was the potential benefits to load of increased competition and the concomitant mitigation of market power. To identify and achieve those benefits on a broader scale, the ISO is currently finalizing a methodology for evaluating all proposed "economic" transmission expansion projects. Thus, the ISO is committed to proactively identifying "needed" expansion of the grid.

Of course, the ISO has always taken seriously its obligation to reliably plan the transmission system. To date, the ISO has approved almost a billion dollars worth of new transmission projects, most of which are necessary to maintain reliable service to load.

The ISO takes a similar position when addressing the transmission constraints that are the genesis of the ISO's RMR requirements. In 1998 the ISO initiated the innovative Local Area Reliability Service (LARS) process, wherein the ISO solicits and identifies potential non-RMR alternatives, including generation, transmission and demand management, that meet the ISO's RMR requirements. In fact, it was through the ISO's transmission planning process that the ISO successfully sponsored the addition of the Jefferson-Martin transmission line into the City of San Francisco. Once in operation, the Jefferson-Martin line will relieve long-standing congestion into the city and will reduce the cities RMR requirement.

In addition, as explained further below, the ISO will also reexamine its interconnection procedures and requirements to ensure that ACAP resources are deliverable (i.e., can satisfy their obligations to provide ACAP).

Finally, at this juncture, the ISO is not convinced that that the implementation of locational marginal pricing and other features of the new market design will create, by themselves, sufficient incentives for transmission expansion. In its Standard Market design rulemaking, even FERC notes that "while price signals should support efficient decisions about consumption and new investment, they are not full substitutes for a transmission planning and expansion process that identifies and causes the construction of needed transmission and generation facilities or demand response."[19] The ISO therefore believes that it must continue to identify and advocate for necessary expansion of the system. The ISO believes this approach to be consistent with the approach FERC has outlined in both Order No. 2000 for RTOs and in its statements regarding the new Wholesale Standard Market Design.

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[19] Federal Energy Regulatory Commission Working Paper on Standardized Transmission Service and Wholesale Electric Market Design, March 15, 2002, p. 6.

Based on these considerations and the comments of market participants, the ISO proposes and commits to the following:

Economic Transmission Expansion – The ISO proposes to finalize, by the end of 2002, its new methodology for evaluating economically-driven transmission expansion and to include that methodology in a FERC filing that outlines a comprehensive and proactive long-term transmission planning process. In the end, the effectiveness of a proactive long-term transmission planning process will largely depend on: 1) FERC acceptance of the process and, consequently, cost-recovery for projects approved through that process; and 2) a willingness of the state to agree that such projects are "needed" and to approve the siting of the new transmission projects;

Potential Sites for New Generation/Transmission – Consistent with certain of the ideas put forth by FERC in its SMD rulemaking process, the ISO proposes to identify, and publish on its website, the preferred sites for new generation and transmission. The ISO is likely to begin with today's RMR areas, but will also identify areas where new generation is likely to have a positive impact on grid operation (reliability), has access to fuel and water supplies, and would not necessarily require major transmission expansion in order to deliver its output to load. As part of this effort, the ISO will aggressively pursue, as explained below, appropriate expansion of the grid as a substitute for RMR generation.

RMR Transition – The ISO is obviously very concerned about the market power implications and potential cost-shift from transitioning from RMR to ACAP. Therefore, the ISO proposes to extend the manner and timeframe for addressing RMR issues. First, the ISO recognizes that although the ISO assesses RMR costs to the applicable PTO, the PTOs have been successful in demonstrating to FERC that such costs are transmission related and therefore should be paid by all users of the grid, wholesale and retail. Thus, under the ISO's ACAP proposal, RMR-related costs that are today paid by all Participating TO load and wheeling transactions in the control area, may, in the future, be borne by location-specific loads on the system. While the ISO does not necessarily believe this to be inappropriate from a cost-signal perspective, the ISO recognizes that it raises certain consistency and equity issues. Therefore, as opposed to the approach outlined in the April 3 Draft Comprehensive Proposal that provided for a RMR-transition to ACAP by January 2004, the ISO now proposes the following:

RMR Phase-Out – The ISO will aggressively pursue, beginning with the 2002 LARS process, expansion of the transmission system and demand-side management programs, as appropriate, to substitute for RMR generation. In light of the lead time necessary to bring such alternatives into service, the ISO's goal will be, to the extent possible, eliminate, at a minimum, Condition 1 RMR units, or those RMR units that meet the intent of Condition 1, by January 2006.[20]

Determination of Local ACAP Requirement – During the transition period discussed above, the ISO will subtract RMR generation from the local ACAP requirement of each LSE, based on a load-weighted percentage. Thus, RMR costs will continue to be borne as they are today, by all transmission users.

[20] Condition 1 RMR units are generally competitive and in most hours can recover their costs from the market. Thus, the payment for condition 1 RMR units is primarily for the right to call the unit on for local reliability. Condition 2 RMR units are not competitive in the market and cannot recover their unit costs from the market. In this case, the ISO pays all of the units costs, but the unit can not bid in the market absent a RMR dispatch instruction. These units, absent a RMR Contract, these units may shut down or would have significant market power and a separate transition timeline may be required.

Assignment/Development of New RMR/ACAP Contract – During the transition period to January 2006, the ISO, in conjunction with both transmission owners and LSEs, will work to develop a form of cost-based ACAP contract that will enable LSEs to mitigate against the exercise of local market power.

5.1.5 The Role of the ISO in ACAP

The imposition of an ACAP obligation will produce an “ACAP market(s)”. The ACAP market, the market before the obligation must be met, is likely to be a West-wide bilateral market that includes the LSEs and all the providers. At this juncture, the ISO does not contemplate facilitating a formal ACAP market. A deficiency market could also exist if the penalty for the monthly obligation is structured to allow for either one-time or continuing corrections. Further, the possibility of unavailability for any given set of resources suggests the need for risk pooling methods such as an insurance market for available capacity. In the end, the ISO believes that these markets are best facilitated by others and not the ISO.

However, as recognized in the April 3 Draft Comprehensive Proposal, the ISO recognizes that there are potential benefits to a centralized ACAP market. First, deficiencies or poor performance in the markets may be more readily identified and addressed if the ISO were to oversee the market. More importantly, the ISO would potentially be better positioned to assess, determine the impact of, and potentially mitigate market power in the ACAP market if it were directly involved in facilitating such a market. The ISO certainly agrees that such markets require strict oversight and monitoring, as market power abuse has been endemic in California. Both the immature market structure and the concentration of ownership and control provide an environment that is not presently conducive to competition. Thus, the ISO believes a gradual transition, and the grand fathering of much of the existing supply, is warranted and will prevent market power from becoming an immediate problem. Furthermore, the provision of ACAP by demand responsive sources will increase the competitiveness of ACAP supply. However, close scrutiny of the ACAP market is warranted.

The ISO believes that FERC will play a critical role in the oversight of the ACAP market. Since the ISO does not propose to establish a formal ACAP market, ACAP obligations will likely be satisfied though bilateral forward market transactions between LSEs and ACAP suppliers. While the ISO assumes such arrangements will be consummated through good-faith, arms-length negotiations between the parties, FERC will by necessity have to maintain a vigilant watch over these transactions in order to prevent the exercise of market power. In addition, the CPUC will play a critical role in the oversight of these transactions. Since the CPUC is likely to establish procurement rules for the state’s IOUs regarding the manner by which they satisfy the ISO’s ACAP obligation, the CPUC will also have a significant role in shaping the ACAP contracts.

In the April 3 Draft Comprehensive Proposal, the ISO questioned whether the ISO should establish certain reporting requirements on LSEs and ACAP suppliers. For example, the ISO questioned whether to require each LSE to report, on a monthly basis, the costs incurred by that LSE in satisfying the ISO’s ACAP Obligation. In addition, the ISO questioned market participants whether it is necessary for the ISO to file monthly reports to FERC on the status and functioning of the ACAP market. As stated in the April 3 Draft Comprehensive Proposal, the ISO believes that such reporting may be critical if the ISO and FERC are to effectively satisfy their market monitoring and enforcement functions. Few market participants provided feedback on this issue. In light of the ISO’s continuing concern with respect to the exercise of market power and its ongoing obligation to monitor the functioning of the market, the ISO will require such reporting and to file regular reports at FERC.

5.1.6 WSCC Resource Adequacy Reporting Requirement

In the April 3 Draft Comprehensive Proposal the ISO proposed to establish an annual planning process that would serve as an early warning system and identify, hopefully years in advance, that insufficient capacity is being planned or built to serve forecast load and would be only for the purpose of gathering information that could be fed into the WSCC's established annual planning reporting process.

A number of market participants questioned the need for this process and stated that the process may be duplicative with the functions of other entities. As noted earlier, it is not the intent of the ISO to duplicate any function or responsibility already in place. Therefore, in order to further streamline the ISO's proposal and to assuage the concerns of other entities that may perform similar functions, the ISO is now proposing to further limit its proposed annual process to the collection of the information necessary to fulfill the established WSCC reporting requirements and to provide for explicit coordination between the ISO and state entities in satisfying such reporting requirements.

As stated by the WSCC, the WSCC was established to promote the reliable operation of the interconnected bulk power system by the coordination and planning of generating and interconnecting transmission facilities. To that end, the WSCC has adopted a "Power Supply Assessment Policy" to "establish a uniform policy for assessing the adequacy of installed and planned resources within the WSCC region for the purposes of reporting within the Council, and to outside agencies." As stated by the WSCC, "such information will allow regulators and policymakers to anticipate potential shortfalls so that determinations can be made as to whether impediment or insufficient incentives exist in the market." The WSCC states that the purpose of the assessment is to "project whether enough resources exist, at any price, to meet load and possible reserves while considering the transmission transfer capabilities of major paths." WSCC states that such an assessment is required to comply with the NERC Planning Standards and that these standards require each region to perform a regional assessment of existing and planned (forecast) adequacy of the bulk electric system. The WSCC-established assessments cover the next 5 years. In support of satisfying this requirement, the WSCC requires each of its member systems to provide the following:

DATA REQUIREMENTS

Load Forecasts

- Electricity demand and energy forecasts, including uncertainties
- Variations due to weather
- Variations due to other factors affecting forecasts

Demand Side Management (DSM) Programs

- Existing and planned demand-side management programs
- Direct controlled interruptible loads
- Aggregate effects of multiple DSM programs.

Resource Information

- Supply-side resource characteristics, including uncertainties
- Consistent generator unit ratings, including seasonal variations and environmental considerations affecting hydro and thermal units

- Availability of generating units
- Fuel type

Transmission Information

- Capabilities, availability of transmission capacity, and other uncertainties.

Therefore, the ISO proposes to establish a formal requirement on its participating systems to submit the above-identified information to the ISO on a periodic basis. In fulfilling its WSCC responsibility to report this data, the ISO will coordinate with the CEC and other affected state agencies to ensure that the information provided to the WSCC is accurate.

5.1.7 ACAP and the Impact on LSEs

The following sections outline the implementation details of the ISO's final ACAP proposal and how that proposal impacts LSEs. Thus, the following sections detail:

1) A LSE's Monthly ACAP Obligation, including:
   a. The determination of the Monthly Reserve Margin – the reserve margin for each LSE that is necessary for the ISO to maintain reliable system operation;
   b. The methodology for determining a LSE's LRA-specific monthly obligation (MW) based on forecast load;
   c. The basis for assessing whether a LSE has acquired sufficient resources to satisfy its monthly obligation;
2) A LSE's daily ACAP Obligation
3) The consequences on a LSE of a ACAP Obligation deficiency;
4) The inter-relationship between ACAP and RMR; and
5) The ACAP Timeline

The sections following detail the opportunities and requirements for suppliers to participate in the ACAP market and outline the ISO's plan for transitioning to a fully effective ACAP requirement.

5.1.7.1 The ACAP Obligation Defined

A LSE's ACAP obligation would consist of three parts: the annual reporting of information to the ISO, the monthly obligation to have resources available for delivery into the day-ahead market and the daily obligation to deliver resources the ISO can commit and dispatch to meet load and provide reserves. In order to more precisely define those obligations, the April 3 Draft Comprehensive Proposal presented in detail how the ISO would determine and apply the monthly ACAP Obligation, including the daily requirements on LSEs that go hand-in-hand with the monthly obligation. The ISO also identified a number of unresolved issues and requested feedback of those open issues. The discussion below sets forth the ISO's final proposal on the determination of the monthly ACAP requirement and addresses how the ISO has resolved any open issues, including the rationale for its proposed approach.

5.1.7.1.1 Determination of the Reserve Margin: Daily Margin Plus Monthly Safety

The ISO's daily operating and regulating reserve level requirements represent the desired level of operating system reliability. The operating reserve requirements of the ISO are those currently established by the Western System Coordinating Council's (WSCC) Minimum

Operating Reliability Criteria (MORC).[21] This daily reserve level (which may vary but must be specified for designing an ACAP obligation on a monthly basis) is sufficient in the day ahead, but, without modification, it will not be sufficient for use as the month-ahead reserve level. This is because the load and plant outage forecasting error on a month-ahead basis is greater than the error from forecasting on a day-ahead basis. Ignoring unplanned outages, if the load forecast is considered to be the expected peak, then there is an approximately 50% chance of the actual peak exceeding the forecast. This chance is the same for the day-ahead forecast, but with the day ahead forecast the expected size of the error is smaller. Hence, a given margin for a monthly forecast has a greater chance of being insufficient than that same margin applied to the day-ahead forecast.[22]

5.1.7.1.2 Accounting for Load-Forecast Error

As stated in the April 3 Draft Comprehensive Proposal, correcting for the difference between the monthly and daily forecast error can be accomplished in the reserve margin calculation or in the forecast itself. If the objective is that the monthly reserve margin have the same probability of sufficiency as the daily reserve requirement, then the monthly forecast could be made to reduce the chance of under-forecast to something less than 50%, i.e. a forecast above the expected value. Under such an approach, the Reserve Margin would not have to account for the difference between the monthly and daily forecast error. Whether the monthly forecast is made as a traditional expected value or is made to hold constant the probability of exceeding some margin is something that must be determined either internally within the ISO or in a broader set of entities including the ISO and standard-setting organizations such as the WSCC. Given a forecasting objective, expected value or otherwise, the monthly margin that corresponds to the day-ahead margin can then be determined.

The ISO solicited feedback on this issue in the April 3 Draft Comprehensive Proposal. Few market participants commented on this topic in general and no one indicated a preference for one option or the other. At this juncture, the ISO is in favor of factoring load-forecast error into the Monthly Reserve Margin. In this manner, the ISO will be able to explicitly and transparently track and indicate its ability to forecast load. As outlined further below, the ISO is advocating determining each LSEs ACAP requirement by first performing a monthly ISO Control Area-wide load forecast (ISO Forecast), applying the factor (1 + MRM), and then determining each LSEs responsibility by multiplying the total ACAP requirement by each LSEs contribution to the ISO’s monthly system peak, based on the prior year’s historical data. The load forecast contingency is therefore based, or driven by, the ISO’s ability to accurately forecast.

5.1.7.1.3 Accounting for Outages

The second part of determining the monthly margin that will achieve the desired day-ahead margin concerns resource outages. The proposed ACAP design provides that the resources that are being offered to meet the ACAP requirement will be adjusted for their expected unavailability. When the ISO considers the outage factors in determining the monthly margin, its main concern is not the planned outages and expected forced outages, since ACAP resources are net of these outages. As explained below, ACAP resources will be required to

[21] The WSCC MORC states that each control area must continuously provide adequate operating reserves to maintain schedule frequency and avoid unplanned loss of load following transmission or generating contingencies.

[22] This use of the reserve margin in comparison to the load forecast errors is not meant to imply this the purpose of the reserve. Rather, it is meant to note the relative level of the reserves in comparison to load when viewed on a month-ahead basis versus a day-ahead basis.

provide resource-specific availability data. The set of ACAP resources being nominated to meet the obligation should not include units whose scheduled outages preclude them from being available when needed within the month. Accounting for the expected outage rate, however, does not mean there cannot be coincident outages for a short period of time like a month or a couple of days. The more diversified (in the financial sense of the term) the set of ACAP resources are, the less the problem of coincidence. Still the Reserve Margin may need to include a few extra percentage points to cover this uncertainty.

In summary, the ACAP Reserve Margin has two components – operating reserves and contingencies - and the second component has two parts. The first component is the operating margin the ISO must maintain and such requirement should be the WSCC's established MORC. The second component is an adjustment that provides a margin of safety for two things: 1) the difference in load forecasting errors between the monthly forecast and the daily forecast, and 2) the likelihood of outages beyond the expected outage level.

5.1.7.1.4 Calculation of the Monthly Reserve Margin

The ISO proposes that the Monthly Reserve Margin (MRM) be calculated by summing historical ISO operating reserve and regulation requirements, a contingency for load forecast error, and a contingency for outages. The contingencies for load forecast error and outages shall consider the following:

(a) Historical accuracy of ISO monthly load forecasts;

(b) Generating unit capability and types for every existing and proposed unit;

(c) Generator forced outage rates for existing mature generating units based on data submitted by the LSEs for their respective systems, from recent experience, and for immature and proposed units based upon forecast rates related to unit types, capabilities and other pertinent characteristics; and

(d) Generator maintenance outage factors and planned outage schedules.

Based on the above, the ISO proposes that the MRM be determined as follows:

MRM = ORM + FCM + OCM

and

ACAP = FMP*(1+MRM)

Where,

FMP: the forecast monthly peak for the ISO system, which shall be the weather-normalized, 50/50 probability load.

ORM: the operating reserve margin, as determined by a review of historical ISO operating reserve procurement levels. As ISO improves operating efficiency or when system efficiency increases with better resource sharing, the ORM may reduce and that will translate into a reduced ACAP requirement.

FCM: Forecast contingency margin. To be decided by historical data and statistical analysis. (Since ACAP is not going to be implemented for almost 2 years there is no need for an exact FCM estimate at this time). FCM may be smaller when all load diversity is considered. FCM may be in the order of 3-6%.

OCM: Outage contingency margin. To be decided by historical data and statistical analysis. OCM should be very small since it does not include planned outages and expected forced outages. OCM should be jointly decided with FCM and

ORM to consider any correlation among various types of contingencies to eliminate any double counting and maximize the utilization of reserve resources. (Since ACAP is not going to be implemented for almost 2 years, there is no need for an exact FCM estimate at this time)

The ISO is will continuing to define the above formulation for determining the MRM and the ACAP requirement during the transition period to full ACAP implementation. Based on the general formula expressed above, the MRM may in the approximate range of 10-12%.

5.1.7.1.5 Specification of ISO Operating Reserve Requirements

The ISO's operating reserve (spin and non-spin) requirements are well defined. The ISO notes, however, that as a result of the PriceWaterhouseCoopers Operations Audit of the ISO, the ISO is developing a formal procedure for determining the amount of Regulation the ISO procures on a daily and hourly basis. The setting of day-ahead and hour-ahead market requirements for upward and downward Regulation Reserve are judgmentally determined by the Generation Dispatcher and the respective day-ahead Grid Resource Coordinator (GRC) or hour-ahead GRC. Considerations taken into account in determining day-ahead market upward and downward Regulation Reserve requirements include the following:

- Prior day's actual system loads;
- Overall performance of the system; and
- Significant changes in the SDLF between certain operating hours (i.e., HE 0600 through HE 0700 and HE 2200 through HE 2400).

Considerations taken into account in determining hour-ahead market upward and downward Regulation Reserve requirements include the following:

- Prior hour's actual system load;
- System load for the same hour of the previous operating day; and
- Overall performance of the system over the last few hours.

In practice, the factors considered by the day-ahead GRC and hour-ahead GRC in determining the amount of Regulation Reserve to procure, differ from the factors set forth in the ISO's existing Operating Procedure. The ISO's intent is to revise the previously implemented formula and to consider a variety of operating deltas to determine the proper amount of Regulation to procure. In addition, real-time deviations that alter the procurement amount in the hour-ahead will be factored into the procedure.

The end result is that, during the transition period to full ACAP implementation, the ISO will endeavor to develop a methodological basis, based on historical and ongoing operating practice, for quantifying the ISO's actual operating reserve and regulation requirements.

5.1.7.2 Determination of a LSE's Locational ACAP Requirement

5.1.7.2.1 Defining a Locational ACAP Requirement

As provided in the April 3 Draft Comprehensive Proposal, the ISO proposes to define the ACAP obligation for the LSE in terms of LRAs. These LRAs are the same as today's RMR Areas. Thus, initially there will be eleven LRAs on the ISO Controlled Grid. The LRAs will reflect the critical subdivisions of the system that require individual designation of the resources to meet load and provide reserves. Since these subdivisions are primarily defined by the transmission constraints that restrict the amount of power that can be imported into such areas to serve area load, the ISO anticipates that, over time, the number of these areas will be reduced as a result of enhanced locational price signals and a proactive transmission planning and expansion process. Finally, the ISO believes that the ACAP requirement for LRAs should reflect the relevant operating nomograms, e.g., a minimum portion of LRA load should be covered by ACAP from within the LRA. This requirement should be prorated to all LSEs in the LRA. As noted earlier, in recognition of the equity and market power concerns raised by market participants, the ISO has proposed to phase out RMR (and thereby phase-in full ACAP) over a longer time horizon, thereby reducing the LSEs exposure to market power and better aligning the ACAP implementation with the inter-related transmission planning/expansion timeframes.

5.1.7.2.2 Assessing Deliverability

A critical feature of the month-ahead ACAP obligation is that the capacity offered to meet the ACAP obligation must be deliverable. In other words, there must be a demonstration that the capacity will be capable of providing reliability benefits to the load that claims that capacity to satisfy its ACAP obligation. The ISO believes that there are two viable approaches to ensuring the deliverability of ACAP resources. First, because the ISO will define the ACAP requirement on a locational or LRA basis, a LSE can ensure deliverability by procuring ACAP resources that are located within the LRA in which all or a portion of its load is located. However, the ISO also recognizes that there are a limited number of potential ACAP resources located within each LRA. Therefore, the ISO recognizes that LSEs may wish to contract with ACAP resources that are distant from a LRA. Thus, as described further below, the ISO is proposing that a LSE can obtain FTRs from the ACAP resource's point of injection to the system (source) to the applicable LRA (sink).

5.1.7.2.3 Satisfying Deliverability Through FTRs

As explained in the April 3 Draft Comprehensive Proposal, a practical alternative to directly assessing the deliverability of a specific ACAP resource is to require FTRs from the injection point (source) of the resource into the system to the LRA (sink). Under this approach, either the LSE or ACAP supplier can obtain, through the annual or monthly FTR auctions, the FTRs required to deliver the ACAP resource. Moreover, the total number of FTRs available to or from an LRA may provide a suitable measure of the amount of ACAP that must be provided from within a particular LRA.[23] However, in order for this to be effective, the Scheduling Coordinator representing the LSE or ACAP resource must schedule the above-described transaction and exercise the physical scheduling priority of the FTR.

The ISO reaffirms its position that LSEs that choose to rely on resources external to an LRA to fulfill their ACAP obligation must procure (and schedule) the necessary FTRs to deliver such resources. The ISO believes that both the FTR product (point-to-point with scheduling priority) and access to such products (first through the direct allocation to load, as described in the FTR Section of this Comprehensive Proposal, and through the annual and monthly FTR auctions) are compatible with and support this requirement.

5.1.8 Proposed Methodology for Determining the Monthly ACAP Requirement

In the April 3 Draft Comprehensive Proposal, the ISO stated that it was currently considering two options for determining a LSE's ACAP obligation. As explained, the difference between the two options under consideration lay in the role of the ISO and LSEs.

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[23] As noted earlier, the number of available FTRs into the LRAs is likely to be based on the operating nomograms that presently and effectively define these areas.

Option 1 - The ISO would determine the ISO's base Control Area ACAP requirement in MWs by multiplying the ISO's forecast monthly peak load and the quantity one (1) plus the Monthly Reserve Margin (MRM). The ISO will then determine the unforced ACAP requirement by multiplying the base requirement by the quantity of one (1) minus the average forced outage rate for the ISO Control Area, based on the same data that is used to determine the MRM, as defined above. The ISO would then determine the ACAP requirement for each LRA by calculating the product of the ISO's Control Area ACAP requirement and the ratio of the LRA's forecast monthly peak load to the sum of the forecast monthly peak loads for all LRAs. Finally, the ISO would determine the ACAP requirement for each LSE would be calculated separately for each LRA in which it serves load. The requirement would be based on each LSE's contribution to each LRA's forecast peak based on actual contributions to the LRA's peak load for the prior calendar year. This approach is similar to that employed in the eastern ISOs.

Option 2 - The monthly ACAP obligation of the LSE would be based upon the forecast coincident (with the ISO's peak) peak load of the LSE. This option would require the UDCs (IOUs and munis) to do the load forecasting. Under this option, the ISO would issue, twelve weeks prior to the start of a month, an ISO forecast by UDC. LSEs would then use that ISO forecast to determine their coincident peak load.

5.1.8.1 Comparative Analysis of the Options:

The ISO has identified the following criteria for use in evaluating the two options:

- Relative ease or difficulty of forecast and forecast reconciliation;
- Compatibility with roles and responsibilities of the ISO (centralized vs decentralized decision making);
- Satisfying reliability objectives of ACAP;
- Potential cost impact on LSEs; and

1. *Relative ease or difficulty of forecast and forecast reconciliation*

Both options contemplate the development of an ISO load forecast. Option 1 involves the development of the LSE ACAP Obligation through an allocation based on historical LSE load data. Option 2 relies on the development of, and ISO reliance on, LSE load forecasts. Therefore, Option 1 is easier to implement, since it does not require the reconciliation of ISO and LSE forecasts, nor does it require penalties or other mechanisms to ensure accurate LSE load forecasts.

2. *Compatibility with roles and responsibilities of the ISO*

Option 1 contemplates a more central reliance on ISO forecasts, although Option 2 also relies, in the first instance, on development of an ISO forecast. Option 2 also requires a proactive ISO role in overseeing, whether through some form of validation or through an after-the-fact assessment and penalties, LSE load forecasting. Option 1 also limits the ISO's role by using historical data and thereby avoids a proactive role for the ISO in overseeing LSE forecasts.

3. *Satisfying reliability objectives of ACAP*

Both Option 1 and Option 2 meet the reliability objectives of ACAP since both options attempt to derive and assign the peak load ACAP requirements of the ISO. Moreover, both methods are susceptible to variations – Option 1 from variations from historical load patterns, Option 2 from poor LSE forecasting.

4. *Potential Cost Impact on the LSEs*

Option 2 appears less costly for the LSEs, in part because it will be driven by LSE forecasts – which could of course result in purposeful under-forecasting. In addition, since the allocation of the ACAP Obligation under Option 1 will be based on historical data, the allocation could result in a higher obligation if the historical data is not representative of then current conditions.

Summary Comparison of the Options

Criterion	Option 1	Option 2
Ease of forecast/reconciliation	Easier	More difficult
Compatibility with roles and responsibilities	More compatible	Relatively less compatible
Satisfying reliability objectives	Meets objectives	Meets objectives
Potential cost impact on LSEs	Only slightly more cost exposure	Only slightly less cost exposure

Recommendation

Based on the above analysis, and the guidelines described above, Option 1 is recommended. Option 1 is more consistent with the role defined for the ISO is this process – that of ensuring reliable system operations – and is simpler.

5.1.9 ISO Assessment of Compliance With the Monthly Obligation

5.1.9.1 Monthly LSE Certifications

Each month, LSEs will submit completed certification forms to the ISO demonstrating that they have obtained sufficient ACAP for the upcoming month. The certification forms shall, at a minimum, require LSEs to: 1) designate the total amount of ACAP they have procured; and 2) specify how much ACAP is associated with ACAP suppliers that are located in each LRA, the remainder of the ISO Control Area and each external Control Area.

As stated in the April 3 Draft Comprehensive Proposal and reconfirmed here, the monthly ACAP Obligation requires that each LSE obtain an amount of ACAP resources equal to its forecasted monthly peak plus a Reserve Margin, i.e. forecasted monthly peak load times the quantity 1 + Reserve Margin. The purpose of the monthly obligation is for the system as a whole to have access to resources that can reasonably be expected to meet the upcoming month's load with sufficient reserves. Therefore, as discussed further below, resources that will provide ACAP must be specified by point of delivery into the system and demonstrate feasibility of delivery to the Local Reliability Area (LRA) in which the LSE's load is located. The resources that satisfy the ACAP requirement can be selected to meet load in its anticipated shape; that is, each LSE will be able to procure the portfolio of ACAP resources that best satisfies its hourly load requirements for a given month.

5.1.9.2 ACAP – Monthly Obligation Assessment Options

Statement of the Issue:

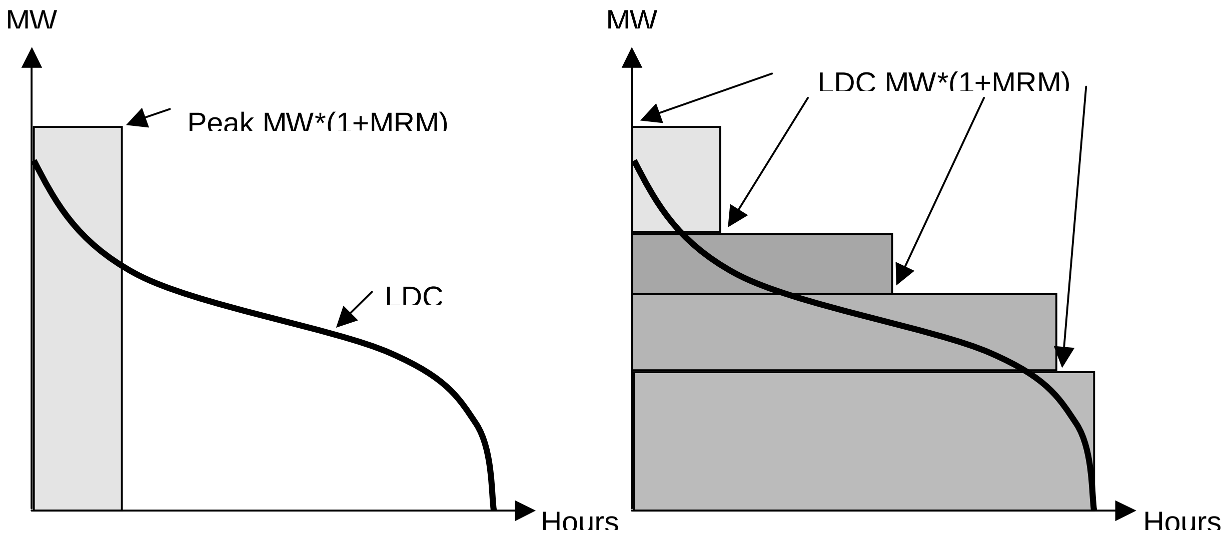
In its April 3 Draft Comprehensive Proposal, the ISO identified two options for measuring compliance with the monthly ACAP obligation as follows:

> ***Option 1:*** Measure an LSE's resources against their peak demand (the hours with a high-probability of being the peak) because it is that load which puts the greatest demand upon the generation resources of the system and, other things being equal, the greatest strain on the system reliability.
>
> ***Option 2***: Measure an LSE's resources against their load for the entire month using a monthly load-duration curve. Under this approach, a LSE could specify the portfolio of resources that it would use to satisfy its hourly load requirements (interruptible load, peakers, hydro, QFs, nuclear, energy contracts, ACAP contracts, etc.). This option would take into account energy and emission limits, as well as planned outages.

Under both options the requirement would be to demonstrate that a LSE has secured resources to cover the product of (1 + MRM) and their forecast load, where MRM is the monthly reserve margin.

***Comparative* Analysis of the Options:**

The following figure schematically demonstrates the two options, using a hypothetical monthly load duration curve (LDC) for a given LSE.



Option 1 Option 2

Under Option 1, the LSE would be responsible to cover the forecast monthly peak load (including the MRM) for a specified number of hours (forecast peak load duration). Under Option 2, the forecast monthly LDC (including the MRM) is approximated by a number of blocks with different durations (including one block for the total number of hours of the month, one for the duration of the monthly peak, and one or more blocks with durations between the two.

The ISO has identified the following criteria for use in evaluating the two options:

- Relative ease or difficulty of forecast and forecast reconciliation;
- Compatibility with roles and responsibilities of the ISO (centralized vs decentralized decision making);
- Satisfying reliability objectives of ACAP;
- Market power mitigation;
- Potential cost impact on LSEs; and
- Incentives for generation investment;

It is assumed that under *both* options the ACAP resources are available for a designated number of hours during the month, but that their exact allocation (commitment) for the different hours of the day is accomplished in the day-ahead (and where relevant hour-ahead, or pre-dispatch) time frame through a combination of SC self scheduling, Unit Commitment Service (UCS) and Residual Unit Commitment (RUC) processes to meet the ISO's reliability objectives. In other words, operational reliability of the system is a centralized function delegated to the ISO (under AB1890) rather than a decentralized task left at the discretion of the transmission users (SCs). If a LSE is short in satisfying its ACAP obligation and is willing to accept firm load curtailment as a consequence, the final decision whether to curtail the deficient SC's load or commit a pool of resources (and charge a deficiency charge to the SC) is left to the ISO based on system reliability considerations (vulnerability to cascading outages, etc.).

1. *Relative ease or difficulty of forecast and forecast reconciliation*

Option 1 involves forecasting the monthly peak and its duration. Option 2 requires determination of the monthly load duration curve (or its approximation by a number of blocks). Option 1 is easier to implement and reconcile the ISO and LSE forecasts.

2. *Compatibility with roles and responsibilities of the ISO*

Option 1 is more in line with the role and responsibility of the ISO, namely ensuring reliability of the system during high demand periods. It leaves the responsibility to "meet the demand" during the rest of the hours to the LSEs, as overseen by the appropriate regulatory agencies. Option 2 may be construed by some (e.g., the State entities) to be an unnecessary intrusion by the ISO outside the peak demand hours – the hours most likely to directly impact, from a total system resource perspective, the ISO's ability to maintain system reliability.

3. *Satisfying reliability objectives of ACAP*

Both Option 1 and Option 2 meet the reliability objectives of ACAP since the ISO can allocate the ACAP resources to cover the peak demand hours of the day under either option. However, Option 2 may be considered slightly superior in that it ensures supply adequacy during shoulder and off-peak hours as well. This fact, of course, needs to be balanced against the appropriate role for the ISO in making such determinations.

4. *Market power mitigation*

Under otherwise comparable structural conditions (ownership and control concentration), the deeper the supply stack, the lower the potential for the exercise of market power (the less the probability of having pivotal suppliers). Option 1 presumably provides for a deep enough supply stack to mitigate system-wide market power during peak hours. Option 2 provides a somewhat superior protection since it ensures supply adequacy for all hours.

5. *Potential Cost Impact on the LSEs*

Option 1 appears less costly for the LSEs to satisfy their ACAP obligation. However, since the exact allocation (commitment) to meet the peak load is driven by reliability objectives, the cost of ACAP under the two options may not be substantially different. In other words, the ACAP providers would internalize the risk of being committed by the ISO (i.e., having to sell only non-firm energy exports in order to ensure adequate ACAP for the ISO's "commitment" call option) for almost as much capacity under Option 1 as Option 2.

6. *Incentives for generation investment*

Option 2 may provide for stronger incentives for generation investment than Option 1 since under Option 2, the LSE would have to line up a variety of contractual arrangements with different time durations (base, cycling, peak). Thus, Option 2 may provide incentives for a more diverse set of potential new generation and demand-response resources. Nonetheless, both options will provide a platform for new investment. Moreover, with respect to resource diversity, the ISO believes that state public policy considerations (fuel-type diversity, environmental considerations, the development of demand response programs) will be a critical and important driver in deciding that issue.

Summary Comparison of the Options

Criterion	Option 1	Option 2
Ease of forecast/reconciliation	Easier	More difficult
Compatibility with roles and responsibilities	More compatible	Relatively less compatible
Satisfying reliability objectives	Meets objectives	Meets objectives
Market power mitigation	Effective	Only slightly more effective
Potential cost impact on LSEs	Only slightly less expensive	Only slightly more expensive
Incentives for new generation investment	Lower	Higher

Recommendation

Based on the above analysis, and the guidelines described above, Option 1 is recommended. Option 1 is more consistent with role defined for the ISO is this process – that of ensuring reliable system operations.

5.1.10 LSEs Daily Obligation

In the April 3 Draft Comprehensive Proposal, the ISO stated that on a daily basis, each LSE will be obligated to provide and schedule the ACAP resources necessary to satisfy its forecast load requirements. The ISO identified two options for satisfying the daily obligation.

> ***Option 1***: Require that a LSE provide and schedule an amount of ACAP resources equal to its next-day's hourly load, plus a fixed percentage (such percentage based on the MRM defined earlier). This option would enable LSEs to shape their ACAP resources to satisfy their hourly load requirements.
>
> ***Option 2***: Require that each LSE make available to the ISO, on a daily basis, their entire monthly portfolio of ACAP resources. The ISO would then determine which resources it must commit for dispatch in order to serve the next day's forecast load. The ISO would optimally commit such resources based on their bids through its unit commitment process. The ISO recognizes that, in light of the strong availability requirements placed on resources, this approach may be onerous and result in higher ACAP costs.

As discussed below, under both Option 1 and 2, the ISO would impose daily penalties on an LSE that fails to schedule and provide the necessary ACAP resources to satisfy its forecast load for that day.

Comparative Analysis of the Options:

The ISO has identified the following criteria for use in evaluating the two options:

- Simplicity
- Compatibility with roles and responsibilities of the ISO;
- Satisfying reliability objectives of ACAP;
- Potential cost impact on LSEs; and

1. Simplicity

Option 1 appears more simple and straightforward. Option 2 requires that the ISO factor in and consider resource constraints to determine an effective commitment.

2. Compatibility with roles and responsibilities of the ISO

Option 1 minimizes the role of the ISO in determining the manner in which resources are committed to serve forecast load. Option 2 contemplates a more central role for the ISO in determining the commitment of resources.

3. *Satisfying reliability objectives of ACAP*

Both Option 1 and Option 2 meet the reliability objectives of ACAP since both ensure that resources are committed in a day-ahead timeframe to serve forecast load.

4. *Potential Cost Impact on the LSEs*

Option 2 is likely to be more costly since it will require all ACAP resources (those necessary to satisfy peak load requirements) to be available for ISO commitment on a daily basis. This will likely increase the cost of ACAP to LSEs.

Summary Comparison of the Options

Criterion	Option 1	Option 2
Simplicity	Easier	More difficult
Compatibility with roles and responsibilities	More compatible	Relatively less compatible
Satisfying reliability objectives	Meets objectives	Meets objectives
Potential cost impact on LSEs	Less expensive	More expensive

Recommendation

Based on the above analysis, and the guidelines described above, Option 1 is recommended. Option 1 is more consistent with the role defined for the ISO is this process – that of ensuring reliable system operations – is simpler and is likely to be less expensive.

5.1.11 Consequences of ACAP Deficiency

In addition to the assessment of monthly deficiency charges, discussed further below, the rules and consequences of a LSE's failure to satisfy the monthly obligation must be clearly specified. Specifically, the role and actions of the ISO must be clearly understood. In the April 3 Draft Comprehensive Proposal the ISO posed the following questions, should the ISO procure ACAP - facilitating a "last resort" ACAP deficiency market with obligatory participation of all available resources? Should non-ACAP resources that participate in the ISO's RUC process (in the long term) be used to cover ACAP deficiencies? As noted in the April 3 Draft Comprehensive Proposal, if the answer to these questions is "No," the ISO must establish procedures for addressing these circumstances.

The April 3 Draft Comprehensive Proposal stated that the ISO was not inclined to facilitate a formal centralized ACAP market. The ISO reaffirms that position here. The ISO believes that such an approach would necessitate a larger role for the ISO in the procurement of resources and engaging in market activity – a role or function that the ISO does not believe is necessary or appropriate for it to assume. Based on that position, the ISO proposes that ACAP-deficient LSEs be required to provide to the ISO an amount of demand-side bids necessary to cover their shortfall. If the ISO cannot meet all demand in real time, these demand-side bids will be called and the deficient LSEs would be asked to curtail the identified amount of load.[24] This proposed requirement and process will protect the LSEs that adequately procure ACAP and will provide incentives to LSEs to procure sufficient ACAP. Moreover, such an approach will enable the ISO to identify, prior to real-time, the resources (supply and demand) necessary to serve load – a key objective of the market redesign effort. In the long-term, the ISO hopes that LSEs, working in coordination with the CPUC, develop demand-response or interruptible programs that are used to satisfy the monthly ACAP obligation in the first instance.

In the April 3 Draft Comprehensive Proposal, the ISO requested feedback on the nature and extent of the ISO's role in satisfying ACAP deficiencies. As noted below, a number of entities have stated that the ISO should not be assuming a central role in ensuring resource adequacy, while a few supported creation of an ISO-facilitated central market for planning reserves – similar to those that are in place in the eastern ISOs. In addition, most entities support, if a resource deficiency is identified, measures to assign the consequence of addressing that deficiency directly to the deficient LSEs – including the required submission by such LSEs of an amount of demand-side bids equal to the deficiency. Based on this feedback, the ISO reaffirms here its intent to adopt the procedures outlined above. Therefore, if, on a monthly basis, the ISO determines that a LSE has not demonstrated that it has procured resources sufficient to satisfy the ISO's ACAP requirement, the ISO will:

1) assess, on an ex post basis, as discussed further below, a deficiency charge based on the seasonally weighted annual cost of a new peaking resource; and

2) require ACAP-deficient LSEs to submit an amount of demand-bids equal to their deficiency and make those bids available to the ISO in a day-ahead timeframe.

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24 In the context of this discussion, it is important to distinguish between outages that are necessitated by certain contingencies (e.g., generating plant or transmission line outages) and those necessitated by a LSE resource deficiency. Demand-bids submitted by an ACAP-deficient LSE would not be called in the context of a "normal" system contingency (outages). Demand-bids submitted by ACAP-deficient LSE would be called when there is a reliability-related need to reduce demand as a result of a system resource deficiency caused by a LSE(s) failing to provide the ISO with adequate resources ("economic outage").

The ISO recognizes the practical implementation issues regarding the second requirement. That is, the ISO understands that the tools and mechanisms necessary to curtail a specific LSE's load do not currently exist (e.g., both regulatory rules, notification requirements and obligations, and the mechanics – the ability to curtail load on specific feeders and substations). Moreover, the development of those tools and mechanism will require close coordination with state regulatory agencies and LSEs. Thus, over the transition period and until ACAP becomes fully effective, the ISO proposes that the ISO, LSEs and state regulatory agencies engage in discussions to assess the feasibility and developmental requirements of implementing such a proposal.

5.1.11.1 Validation and Enforcement

The ACAP obligation serves as a checkpoint of the system with regard to the sufficiency of resources necessary to satisfy the ISO's operating requirements. Therefore, satisfaction of the monthly obligation must be validated and there must be severe penalties for deficiencies with respect to that obligation. The penalties for insufficient resources will be structured around the monthly obligation and daily obligation.

5.1.11.2 The LSE Monthly Deficiency Charge

The penalty for a deficiency in meeting the monthly obligation will be weighted on a monthly or seasonal basis and chosen to reflect the probability of attaining peak for the month or season.[25] The monthly penalty will be derived from the cost of new peaking capacity for the LRA. The penalty must be large enough so that there is no incentive for LSEs to rely upon the penalty for deficiency as a means of meeting peak month capacity needs. The size of the monthly and daily penalties, the monthly or seasonal weights, and penalty differences between first occurrence and subsequent occurrences will work together to provide a severe penalty for monthly deficiency yet keep an incentive to cure the deficiency during the month. The objective of the penalty structure is to make ACAP deficiency significantly more expensive than procurement of ACAP without having the penalties be unnecessarily harsh.[26]

The ISO reaffirms here the proposed deficiency charge set forth in the April 3 Draft Comprehensive Proposal. The ISO estimates the current cost of new peaking capacity in the range of $70-185/kw-year. Therefore, the monthly charge should be a prorated share of the annual cost of a peaker. In addition, the ISO believes that it is critical to set the summer deficiency charge as high as the annual cost and to set other months at a lower level. Therefore, based on the above, the ISO proposes a monthly ACAP deficiency charge equal to the following:

Summer months: June-August: $50/kw-month.

Shoulder months: March, May, September, October: $30/kw-month.

Winter months: December-February.: $40/kw-month

Spring and Fall: April and November: $20/kw-month

The ISO proposes to assess these charges on an ex post (after-the-fact) basis. Thus, each month, during the ISO's initial monthly assessment of LSEs ACAP sufficiency, the ISO will identify deficient LSEs and notify such LSEs of the amount of deficiency charge that they face if

25 An alternative weighting method could use Loss of Load Probabilities or other similar methods that included a generation component in the measure.

they fail to address their deficiency prior to the operating month. Subsequent to the end of a given operating month, the ISO will assess whether a LSE actual satisfied, on a daily basis, its ACAP requirement. This will require an examination of the LSEs schedules and actual loads. If it did, the ISO will not assess a deficiency charge. If it is determined that the LSE did not address or remedy the previously identified deficiency, the ISO will assess the previously determined charge. Moreover, during the given month, to the extent the LSE failed to remedy the identified deficiency, the ISO may curtail the LSE's load, via its required submission of demand bids, as explained above.

5.1.11.3 The LSE Daily Deficiency Charge

In the day ahead market, the LSE must provide a set of ACAP resources, for each of the LRAs where it has load, that will meet the daily forecast requirements. Until a LSE has provided a sufficient set of resources (that have also been confirmed available by the resource), the obligation to provide such resources resides with the LSE. Failure to meet that daily obligation will result in a daily penalty to the LSE. The LSE can meet its monthly obligation but fail to meet its daily obligation because of the unavailability of the resources after the beginning of the month. The LSE may also fail to meet its daily obligation because it has a monthly deficiency.[27] However, a monthly deficiency does not automatically become a daily deficiency unless the forecast daily requirements of the LSE necessitates a level of ACAP for which there is a deficiency.[28]

The dollar penalties per unit of capacity for LSE deficiency toward the daily obligation and unavailability of confirmed ACAP resources will be the same and will be equal to a multiple of the cost of replacement resources high enough to discourage physical withholding.

5.1.11.4 The ACAP Supplier Deficiency Charge

For the ACAP resources provided (and confirmed by the resource itself) to the ISO to meet the daily needs of the system, the daily obligation to provide ACAP by the LSE becomes an obligation for the resource to be available. If the resource then turns out not to be available, it should incur an availability penalty (in addition to whatever penalties it incurs for schedule deviations, etc.).

As noted above, the dollar penalties per unit of capacity for LSE deficiency toward the daily obligation and unavailability of confirmed ACAP resources should be the same and should be equal to a multiple of the cost of replacement resources high enough to discourage physical withholding. In addition, the ACAP resource will incur an additional implicit penalty in that there will be an adjustment of the unavailability rate used in determining the future amount of ACAP it can offer toward the monthly obligation.

With respect to the assessment of these penalties, specifically the daily availability penalty, the ISO believes that LSEs should incorporate these penalties into their agreements with ACAP suppliers and should also be responsible for enforcement. A number of LSEs supported this approach and the ISO agrees. Assessment of supplier penalties should, in the first instance,

[27] If the ISO assumes the role of purchaser of any deficiency from the monthly ACAP obligation, then it is not necessary to have an incentive for the LSE to remove the deficiency during the month. The ISO will have taken those steps. Therefore, the principal rationale for having a daily obligation on the LSE is removed, and obligation during the month can be treated as an availability issue with regard to only the ACAP providers.

[28] For instance, if the monthly obligation was 500 MWs and there was a 50 MW deficiency, then a call for 350 MWs of ACAP would not cause a daily deficiency because there was 450 MWs of ACAP provided.

occur through LSE administration of the LSE-ACAP supplier contracts. The ISO understands that it may have to participate in (or at least provide data for) compliance assessment.

5.1.11.5 Forced Outage Penalties for ACAP Resources

Similar to the discussion above, the ISO recommends that suppliers face penalties for forced outages. As detailed in the April 3 Draft Comprehensive Proposal, the ISO proposes the following: First, the ISO defines scarcity hours as any hour that total available capacity < Load + MRM%. Then define one outage incidence as any number of outages within a day. If an outage lasts beyond a day, it will be counted as 2 or more incidences. For each outage incidence outside scarcity hours, the penalty will be $1/30^{th}$ of monthly deficiency charge. For each outage incidence that overlaps with scarcity hours, the penalty will be 1/3 of monthly deficiency charge.

Once again, the ISO believes that such penalties are best administered by the LSEs in their contractual arrangements with ACAP suppliers, thus appropriately minimizing the ISO's role.

5.1.12 ACAP and the Impact on RMR

As posed in the April 3 Draft Comprehensive Proposal, a natural and obvious question that arises when considering the ACAP proposal: What is the interrelationship between ACAP and RMR?

The ISO designates RMR Units annually to address the local reliability needs and to resolve intra-zonal congestion. The pool of existing RMR Units is clearly a source of ACAP supply. More importantly, since the ISO intends to define the ACAP requirement by location (i.e., on an LRA basis), RMR Generation becomes all that more important to LSEs that need to procure locational ACAP resources. Thus, to the extent that an LSE must satisfy a locational RMR requirement, an RMR Unit in that LRA could count towards that requirement (conversely, however, if the ACAP resource is outside the LRA, the amount of ACAP will have to be adjusted for the relevant transfer capability into the LRA that it would provide service for).

As noted earlier, a number of market participants expressed concerns regarding the ISO's ACAP proposal and is potential impact on RMR. In addition, the ISO itself is and must remain cognizant of the interplay between ACAP and RMR since it is in part through the existing RMR generation that the ISO is able to maintain grid reliability. As summarized earlier and further explained below, the ISO's final ACAP proposal addresses the market power issues by 1) extending the timeframe for effective long-term ACAP implementation (and the phase-out of RMR) and 2) providing for the development/continuation of cost-based mechanisms for addressing the local market power concerns.

5.1.12.1 Locational Market Power

As discussed in the April 3 Draft Comprehensive Proposal, RMR Units, by definition, have locational market power and therefore are presently required to execute a cost-based RMR Contract with the ISO. Thus, going forward, if those contracts are terminated, the opportunity for arms length negotiations between a RMR Unit owner and a LSE is limited. However, the RMR Contracts allow the ISO to assign the existing cost-based RMR Contract from the ISO to any party, including a LSE. The logical assignment would be to assign the RMR Contract to the LSE of the appropriate existing Participating Transmission Owner. The Participating TOs are the parties that have paid the contracts to date, assisted in negotiating the contracts, and are involved in contract administration today. The ISO, working in conjunction with the LSEs and PTOs, will certainly pursue this option during the transition period to full ACAP implementation. In addition, during the transition period, it may be advisable for the ISO and LSEs to revisit the current form, structure and payment terms of the existing RMR Contracts. This option should not be discarded quickly. Finally, as explained earlier, the ISO is not proposing, in this Final Comprehensive Proposal, to phase out RMR over a longer period. Whereas the ISO proposes a two-year phase out of RMR (except for Condition 2 units) in the April 3 Draft Comprehensive Proposal, the ISO is now proposing an almost four year phase-out of RMR. A longer transition to full ACAP effectiveness will allow for the assignment/development of cost-based contracts and will permit the ISO to pursue, through its transmission planning efforts, expansion of the grid in these LRAs in order to increase import capability and thereby potentially reduce the RMR requirements in these areas. The ISO believes that this approach reasonably and prudently addresses the local market power concerns. More generally, the longer timeframe will also better position LSEs in their negotiations with suppliers, since the longer the timeframe, the less likely suppliers will be able to exercise market power.

5.1.12.2 Contract and Control of RMR Generation

As originally discussed in the April 3 Draft Comprehensive Proposal, another issues of concern with respect to the transition from RMR to ACAP pertains to the control of RMR resources. Today, RMR Units are units that the ISO has the right to dispatch in advance of the forward market to maintain local reliability and manage intra-zonal congestion. Therefore, the operation of these units is and must remain under the control of the ISO. Thus, transfer of existing RMR Contracts from the ISO to a LSE can only prudently occur if the ISO maintains its ability to dispatch the unit for the sole purpose of maintaining system reliability.

5.1.12.3 The Transition From RMR to ACAP

In the long-term, the ISO foresees a full transition from today's RMR paradigm to an ACAP paradigm. However, the ISO foresees a multi-year transition plan that would continue the existing RMR structure through December 31, 2003. During this period, a load-weighted percentage of RMR capacity will be deducted from each LSE's obligation in a LRA. Additionally, during this period the ISO will fully develop a transition plan that may include:

- Assignment of the RMR Contracts to LSEs with the ability for the ISO to request dispatch if needed for reliability of the ISO Control Area; or
- The ISO may terminate all existing RMR Contracts that are Condition 1, or meet the intent of Condition 1. The ISO may retain all Condition 2 RMR Contracts. In addition, prior to termination of any RMR Contract, the ISO must have sought and been granted the ability to call on such resource to address locational requirements at a mitigated price.

5.1.13 Temporal Dimensions and Timeline

Under the proposed ACAP obligation, a LSE is responsible for providing a demonstration that it has enough capacity to meet the monthly peak with a reserve. Each source of ACAP supply must be identified. This is done in the month before the month in which the capacity must be available to serve a LSE's load.

Once in the month of the obligation, the LSE has the responsibility to identify each ACAP resource necessary to meet the daily demands of its forecast loads. To the extent not self-scheduled by the Scheduling Coordinator representing the LSE, the ISO can, if necessary, commit the capacity in the day-ahead timeframe for potential dispatch the following operating day. The LSE's specification (and provider's confirmation) has to be done before the ISO's unit commitment process. As noted above, failure to provide sufficient confirmed ACAP at this stage incurs the daily penalty for the LSE.

After the LSE has specified the resources and those resources have confirmed their availability, those resources are individually responsible for being available and the ISO becomes the enforcer.

The following timeline shows the sequence of events before and then in the month of obligation. The timing offered in the sequence is approximate.

5.1.13.1 ACAP Timeline – before month of obligation

- Annual (+): CPUC and CEC review IOU resource plans
- Annually: LSEs provide ISO with updated WSCC five-year resource data based on WSCC requirements

In period leading to month of obligation

- Twelve weeks prior: ISO issues ISO forecast, by UDC.
- Two months prior: new generation resources identified as potential ACAP providers
- Eight weeks prior: LSEs provide load forecasts to ISO.
- Seven weeks prior: ISO review of LSE forecasts. ISO determines if sum of LSE forecasts is greater than or equal to ISO forecast (on a UDC basis)
- Six weeks prior: forecast allocated to LSEs by LRA
- One month prior: ISO publishes ACAP obligations for LSEs
- Three weeks prior: LSEs report set of ACAP resources to meet obligation to ISO
- Two weeks prior: ISO review of feasibility of each LSE's set of ACAP resources
- One week prior: LSEs report final set of ACAP resources to ISO
- One day prior: Monthly Deficiency penalty notifications issued by ISO

5.1.13.2 ACAP Timeline – within month of obligation

- LSE identifies, and the individual resources confirm, the ACAP for each day on a day-ahead basis
- Deficiency in the amount of confirmed, available capacity triggers LSE daily penalty
- Applicable ACAP resources must participate (schedule and bid) in the day-ahead markets
- Based on ex post assessment of LSE ACAP compliance, ISO determines final monthly ACAP Deficiency Charge for prior month.

5.1.14 ACAP and the Impact on Suppliers

The following subsections explain the opportunities and requirements for suppliers that participate in the ACAP market..

5.1.14.1 The Eligibility to Provide ACAP

In that the purpose of an ACAP requirement is to provide a month-ahead checkpoint that integrates with the ISO's daily operation, all efforts will be made to be as inclusive as possible in determining what resources can provide ACAP towards the monthly obligation. Resources that provide ACAP do not have to be available all hours of the month because the ISO will not call upon them all hours. Thus, energy-limited resources and resources whose power is confined to certain hours can provide ACAP. However, resources must have some way for demonstrating their nominated capacity. Similarly, resources must show that they can be controlled by the ISO in a manner consistent with the delivery of ACAP. In addition, resources must offer ACAP that is available to the LRA, i.e. it must be feasibly deliverable. And finally, resources cannot be counted twice in the provision of ACAP.

The resources that can be used to meet the ACAP obligation include:

- Specific generation and load-based resources within the ISO control area (PGA and PLA ACAP Resources)
- PGA or PLA resources aggregated into LRA-specific portfolios (ACAP LRA Portfolio Resource);
- External resources (i.e., ACAP System Resources);
- Demand response resources that can be controlled by the ISO (qualifying ACAP UDC Interruptible Load programs);
- Contract power that can serve in the manner of available capacity

5.1.14.2 ACAP Requirements Applicable to ACAP Suppliers

5.1.14.2.1 Participating Generator and Participating Load Agreement ACAP Resources

All Participating Generators and Participating Loads should be able to provide ACAP given that the appropriate contractual access to the resource is obtained by the LSE. These resources include energy-limited resources and intermittent resources. New generation not currently accessible through ISO controls will have to be identified and specified for such control at least a month before its use in a month of obligation.

All PGA and PLA resources will be eligible to provide ACAP to the extent that they agree to the comply with the following requirements:

a. Perform Demonstrated Maximum Net Capability (DMNC) tests in accordance with established ISO Procedures for determining the Pmax of a PGA or PLA Resource. Such DMNC test will be required before a Generating Unit or Load can qualify as a PGA or PLA ACAP Resource;

b. Comply with the ISO's established procedures for Outage Coordination, as those requirements are specified in ISO Tariff Section 5.5.

c. Provide to the ISO, by the 20^{th} day of each month, GADS data or data equivalent to GADS data pertaining to the previous month (See Exhibit A);

d. When an ACAP resource (the "seller") sells ACAP to another ACAP resource (the "purchaser"), the Seller and the Purchaser may designate the Purchaser as the entity responsible for fulfilling the obligations and requirements set forth in the ISO Tariff. Such designation shall be made in writing to the ISO at least five (5) calendar days before the date by which any of the relevant obligations or requirements must be fulfilled. If no designation is made to the ISO, the Seller shall be responsible for fulfilling all the obligations and requirements set forth in the ISO Tariff. The Purchasers that are designated pursuant to the preceding paragraph shall be subject to the sanctions provided in Section of the ISO Tariff as if they were a Seller.

e. For every hour of any day that a PGA/PLA ACAP Resource has been identified to provide ACAP, such ACAP Resource must provide its ACAP capacity through a combination of scheduling or bidding in the ISO's day-ahead market.

5.1.14.2.2 LRA Portfolio ACAP Resources

In light of the strict availability requirements that will be placed on ACAP suppliers, the ISO believes that it is reasonable to permit the aggregation of ACAP resources on an LRA basis. Therefore, potential ACAP suppliers will be permitted to develop portfolios of ACAP resources within LRAs, thus enabling the owner(s) of such resources to reduce their potential risk and financial exposure from forced outages or other unforeseen circumstances.[29]

Initially, there will be eleven defined LRAs for purposes of creating an LRA Portfolio ACAP Resource. The eleven areas will be those identified and posted on the ISO website. As noted above, in the future, the number and configuration of these areas may change. Therefore, on a prospective basis, the ISO may establish larger areas for which ACAP portfolios will be permitted.

At present, the ISO anticipates establishing the following requirements for and limitations on ACAP portfolio creation. Within the LRAs a single entity may aggregate its PGA or PLA resources into a portfolio for the purposes of creating a LRA Portfolio ACAP Resource, so long as:

1) All the PGA or PLA Resources are located within the same LRA; or
2) For PGA or PLA Resources located outside of the LRA, the applicable LSE or LRA Portfolio ACAP Resource owner has secured Firm Transmission Rights from the point of injection of the PGA or PLA Resource onto the ISO Controlled Grid (source) to the LRA (sink);
3) For each PGA or PLA resource in its portfolio, it satisfies the required DMNC, Outage Coordination, and Operating Data requirements specified above.
4) For every hour of any day that a LRA Portfolio ACAP Resource has been identified to provide ACAP, such ACAP Resource must provide its ACAP capacity through a combination of scheduling or bidding in the ISO's day-ahead market.

5.1.14.2.3 System Resource- ACAP Resources

California has traditionally relied on imported power, and that power has served California needs to maintain the reliability of the system. At present, the ISO does not see any need to limit the amount of ACAP capacity that is supplied from other control areas, except to the extent limited by the transfer capability from an external control area to the ISO's control area. How to specify the requirements for an external resource to provide ACAP is a critical part of determining the amount of ACAP that these out-of-control resources will be able to provide. At a minimum external resources or the LSE using them for ACAP must:

[29] This capability will not relieve the constraints (limited to resources connected to the same bus) on resources on netting uninstructed deviations, as proposed in Amendment No. 42 to the ISO Tariff.

1) certify that the control area in which the ACAP System Resource is located will not recall or curtail, for purposes of satisfying its own control area load, imports from that control area into the ISO control area of an amount of energy equal to the ACAP capacity that ACAP System Resource is supplying to the ISO control area;
2) certify that the control area in which the ACAP System Resource is located will afford the ISO control area the same curtailment priority that it affords its own control area load;
3) identify the delivery point to the ISO system;
4) verify that it has made all arrangements required by its control area to ensure that the energy associated with the ACAP System Resources sale to the ISO control area will be delivered to the ISO control area. For example, an ACAP System Resource located in Bonneville Power Administration's (Bonneville) Control Area must demonstrate that it has acquired firm transmission service from Bonneville from the point(s) of injection on the Bonneville system to the point of delivery identified in (3) above;
5) verify that it has acquired Firm Transmission Rights from the point of delivery identified in (3) above (source) to the LRA to which it is supplying ACAP (sink);
6) the nature of the underlying source of the power; and
7) the means of contractual control.

5.1.14.2.4 UDC Interruptible Load Program ACAP Resources

Demand response offers a large potential, internal ACAP resource, particularly for transmission-constrained areas. The principal issue regarding the use of programmatic demand response is one of control. The ISO will have to coordinate with the UDCs and the CPUC, if applicable, to implement a control structure where individual loads are not accessible to the ISO.

At present, the ISO anticipates that the following procedures should apply to UDC interruptible Load Program ACAP resources that are metered by the ISO:

1) Such resources must be bid into the day-ahead market as price cap bid load. These resources will be scheduled based on their bids and day-ahead prices;
2) In real-time, these resources determine whether, and at what level, to purchase energy or to interrupt through their bids into the hour-ahead market;
3) If the load chooses to purchase energy, it will pay the nodal price for the difference between its scheduled load and the load for which it is purchasing;
4) These resources must interrupt, if requested to do so by the ISO;
5) These resources must notify the ISO at least thirty days prior to the beginning of a scheduled maintenance period that would reduce their ability to interrupt during an upcoming period;
6) These resources must notify the ISO of any major equipment that is out of service and therefore cannot be interrupted because it is already off, and notify the ISO when the equipment is coming back on;
7) These resources must provide the ISO with a written commitment that any scheduled maintenance that would reduce their ability to interrupt without reducing load will only be conducted from November 1st through March 31st of any calendar year.

5.1.14.2.5 **Contract *Power ACAP Resources***

For a discussion on the treatment and requirements for these resources, please see the Transition Plan discussion regarding treatment of existing contracts.

5.1.15 Interconnection Requirements for New ACAP Resources

As originally explained in the April 3 Draft Comprehensive Proposal, the ISO will likely need to develop and implement new interconnection requirements for generation that is proposed to be a certified ACAP resource. These requirements are likely to require that a resources full or ACAP certified output be "deliverable" to load. That is, if the developer of a potential ACAP resource contracts with an LSE for the delivery of 1000 MWs, that resource will be required to pay for/construct interconnection facilities and potentially transmission upgrades necessary to ensure the delivery of all 1000 MWs.

The ISO continues to believe that such requirements are consistent with the direction of FERC's ongoing rulemaking on standardizing generator interconnection procedures and agreements. In the ongoing rulemaking, FERC has identified two types of interconnection service. The first is identified as Energy Resource Interconnection Service and is applicable to resources that request interconnection service recognizing that they may not be able to deliver their full output to load. The second is labeled Network Resource Interconnection Service and is intended for resources that wish to compete with existing resources for the ability to serve network customers on the grid. The requirements for this service are thus more stringent than those required for Energy Resource Interconnection Service. The cost-responsibility for the direct and network transmission facilities necessary to interconnect the new ACAP resource is an unresolved issue. Therefore, the ISO proposes to continue to track and participate in the FERC rulemaking proceeding in order to assess and determine the resulting FERC policy on generator interconnections.

5.1.16 The Transition Plan for Implementing ACAP

In the April 3 Draft Design Proposal, the ISO identified three options for transitioning in the full ACAP obligation: 1) the obligation can first be implemented on an informational basis: 2) the obligation can be phased-in over a period of years; or 3) the obligation can be fully implemented on day one.

While the ISO expressed a preference for transitioning to a fully-effective ACAP by establishing, on October 1, 2002, the ACAP obligation as an information-only process with a gradual phase-in over time of the requisite penalties, feedback from the ISO's Governing Board indicated a discomfort with implementing any form of "transitional" ACAP, even an information-only process. The ISO Governing Board stated, among other things, that it would not be reasonable to implement any form of interim ACAP proposal until such time as it was clear to whom the ACAP Obligation would apply. Thus, at this time, the ISO does not propose to implement ACAP until January 1, 2004. By that time, the ISO believes that IOU creditworthiness issues will have been resolved and the CPUC will have issued its final order in the IOU procurement rulemaking process.

5.1.16.1 Transitional and Developmental Issues

The transition to a full ACAP faces many developmental hurdles. These include:

1) Development of the information infra-structure to support ACAP obligation.
2) Translation of existing contracts, such as the DWR and IPP contracts;

3) Incorporation of existing features of Municipal planning and resource adequacy processes and requirements;
4) Treatment of new ACAP resources; and
5) The phase-out of RMR.

5.1.16.2 Information Structures

The creation of the ACAP obligation introduces certain complexities and new features into the California power markets. This feature will require that LSEs, UDCs, power marketers and the ISO interact and do business differently. Thus, each entity will need to create the information infra-structure and support systems required to implement the ACAP obligation. In addition to internal systems for tracking ACAP, systems for transferring information will need to be worked out.

Therefore, the ISO believes that the transition plan for ACAP implementation must accommodate the development of the necessary information infra-structure. It is important to get the accounting of the ACAP obligation worked out. There are a number of points when information is passed between the ISO, LSEs and ACAP suppliers. These include:

- The annual submission of 5-year resource planning information. This information needs to conform to the requirements of the WSCC;
- The periodic submission of historic LSE load data on an LRA basis. This may require the existing UDCs to modify their existing forecasting and data collection tools;
- The submission of month-ahead load forecast data by the LSEs to the ISO for its review and feedback;
- The ISO's dissemination of system-wide and LRA specific load forecast data. This may require the ISO to develop or modify existing forecasting tools;
- The ISO's dissemination of each LSE's ACAP requirements to the LSEs. As explained above, this may require the ISO to develop system-wide resource availability measures;
- The receipt by the ISO of Governmental Entity resource planning data and information;
- The receipt by the ISO of availability, operating, outage and other data from ACAP resources;
- The receipt of information by the ISO of information regarding the location, FTR data, and other information necessary to ensure the deliverability of ACAP resources;
- The receipt by the ISO of meter data from ACAP resources;
- The receipt and review of information regarding existing contracts in order to determine their qualifications an ACAP resource; and
- The receipt of information by the ISO from ACAP suppliers and potentially other control areas regarding ACAP System resources.

Any of these points can become a bottleneck in the implementation of the ACAP obligation. More importantly, as identified above, the required information identified above may require the development of new forecasting and data collection tools. In addition, concerns over the treatment of confidential information may have to be addressed. The ISO is committed to work with market participants and state agencies during the ACAP transition period to plan and accommodate the development of such tools and mechanisms.

5.1.16.3 Grandfathering of Existing Contracts

In the April 19, 2002 Comprehensive Design Proposal, ISO management recognized that the ACAP obligation and process should accommodate and recognize, to the maximum extent possible, existing supply arrangements (including contracts entered into by the State during the past one to two years). At that time Management stated that this would ultimately involve a review and translation of existing supply contracts in order to determine whether and to what extent these contracts qualify as an ACAP resource. At the April 25, 3002 ISO Governing Board meeting, the Board resolved “that any ACAP give full credit to any contracts endorsed by CERS.”

The ISO recognizes that the existing contacts (including the State’s) did not contemplate an ACAP obligation and were written accordingly. While recognizing, by necessity, the validity of contracts entered into by the State, the ISO also intends to remain flexible when determining whether and to what extent any other existing contract qualifies for ACAP. In all likelihood, these other contracts will have to be reviewed and a determination made on a contract-by-contract basis. The intent, however, is to maximize the amount of grandfathering, while remaining consistent with the objectives of the ACAP obligation.

The ISO believes that in most circumstances existing firm energy contracts, call options, and imports will qualify as ACAP resources. However, the ISO believes that, to the extent a form of supply has uncertainty associated with its delivery, such resource may not fully qualify as an ACAP resource. The ISO believes that grandfathering should be limited to firm capacity and energy contracts. For example, to the extent a LSE has contracted for the delivery of non-firm energy from another control area, such resource would not qualify as ACAP. Moreover, a “conditional firm” contract may or may not qualify as an ACAP resource. For purposes of this discussion, the ISO uses “firm” as defined under WSCC standards.

With regard to power purchase agreements (“PPAs”) with cogenerators and qualifying facilities, the IOU may use the PPA quantity to meet their ACAP requirement provided the IOU incorporates the facilities gross load in their LSE requirement. Additionally, to the extent that the IOU uses the PPA to meet its ACAP requirement, all penalties discussed above would apply.

In addition, the ISO believes that it is appropriate to determine an “ACAP equivalence” for both unit-specific existing firm energy contracts and existing contracts that supplied from system resources (both within and outside the ISO’s control area). For unit-specific contracts, the ISO believes should be adjusted to reflect that unit’s historical availability. For system resources, the extent and deliverability of the portfolio will bear the equivalence determination.

Finally, the ISO also believes that the grandfathering should be limited to some reasonable time period. For example, the could limit the grandfathering period to contracts entered into prior to October 1, 2002. Alternatively, the ISO could provide a grace period (e.g., until October 1, 2003) and grandfather contracts executed up to that date.

5.1.16.4 Treatment of Utility-Owned Generation

The ISO believes that all utility-retained generation (URG) will qualify as ACAP resources. The question remains, however, as to whether and to what extent that existing generation should be evaluated to determine an “ACAP equivalence”. At this point in time, the ISO believes that it is appropriate to review the historic availability of such resources for purposes of determining the amount of ACAP each resource would qualify to provide. Obviously, the URG is highly diversified by resource type – nuclear, coal, biomass, gas, wind, etc. To the extent that resource-specific availability data is not available, the ISO would propose to use resource-type (i.e., not unit specific) availability data. Such a review and evaluation will take considerable time and effort. The transition plan must accommodate such a review.

5.1.16.5 Governmental Entities Planning Processes and Requirements

Governmental entities have long planned their systems to ensure resource adequacy. In fact, during the advent of competition, while other entities were moving away from the concept of long-range resource planning, Governmental Entities were continuing to plan their systems to ensure that they had sufficient resources to satisfy their future load. The ISO believes that its proposed ACAP requirements and process must recognize this fact and not create conflicts with existing Governmental Entity planning and resource adequacy standards. Based on its current understanding of these standards, the ISO does not believe that its proposed standards or requirements necessarily conflict with established Governmental Entity standards. In most cases, the ISO believes that the existing Governmental Entity standards are more stringent than those proposed by the ISO. However, the ISO believes that review of, and discussions regarding, the interface between the ISO's ACAP proposal and established Municipal planning and resource adequacy standards is warranted.

5.1.16.6 Treatment of New ACAP Resources

As noted above, the ISO will have to develop standards and procedures to determine whether new resources qualify as ACAP. Among other things, the ISO will have to receive and review operating, availability and outage information, as well as information conforming the availability of such resources. While the ISO already has certain mechanisms and procedure in place to receive and process this information, new information databases and review procedures will have to be established. Moreover, new compliance measures, including metering data receipt and review, will have to be developed. Finally, as explained above, the ISO may have to develop new interconnection requirements for new ACAP resources.

5.1.16.7 RMR Phase-Out

As explained earlier, the ISO proposes to phase-our RMR generation over approximately four years. Such phase-out will require close coordination among the ISO, affected LSEs and the existing PTOs. The ISO must ensure that: 1) to the extent not eliminated through transmission upgrades, that RMR Generation remain available to the ISO for dispatch under mitigated prices. This will require: 1) the development of procedures analogous to those that exist in other ISOs for managing local area constraints; and 2) that appropriate contractual arrangements are in place and available to the LSEs to ensure that they have access to such generation at just and reasonable prices. The ISO believes that such issues can be addressed during the proposed phase-out period for RMR.

5.1.17 Conclusion

The ISO firmly believes that the proposed ACAP Obligation is necessary to support reliable operation of the system. It is imperative that the MD02 initiative result in a significant shift of operating decisions and actions from real-time to the forward market. The ISO believes that the ACAP Obligation will play a key role in achieving that goal of the market redesign. The ACAP Obligation will place on the LSEs the clear responsibility to procure, in the forward market, the resources necessary to serve their forecast load. Most importantly, the ACAP Obligation will require the LSEs to schedule and offer those resources in the day-ahead market. The importance of these objectives cannot be over-emphasized when considering grid reliability and stable operations.

The ACAP obligation will necessitate and result in the creation of new market mechanisms. It is of vital importance to recognize the chance of unforeseen or unintended consequences from the implementation of a new market design. The ISO is therefore committed to remain flexible and ready to receive feedback from its market monitoring unit and market participants about impediments and problems associated with the ACAP obligation (for example, will reliance on bi-lateral markets add an entry barrier for new LSEs and will the ISO be urged to facilitate a central market for reserves). The ISO can then use this feedback to determine how to improve the ACAP obligation and its concomitant requirements going forward. Notwithstanding the size of this effort, the ISO is committed to working with all LSEs and affected regulatory agencies in implementing the ACAP proposal.

5.2 Forward Congestion Management and Energy Market

5.2.1 Introduction

The ISO proposes to implement an integrated forward congestion management procedure that includes:

1. Management of congestion using a full network model that enforces all transmission constraints and eliminates the distinction between inter-zonal and intra-zonal congestion;
2. A forward energy market that eliminates the Market Separation Rule and the balanced schedule requirement, clears all economic demand and supply bids, and produces locational marginal energy prices at the nodal level;
3. Simultaneous ancillary services procurement; and
4. A transmission constrained unit commitment service, which would provide options to preserve flexibility for those SCs that wish to self-commit resources.[30]

Because the proposed design is such a dramatic departure from the ISO's current congestion management design, its implementation will be a complex task for both the ISO and the market participants. The implementation timetable must recognize this complexity and must be realistic. The most complex aspect of implementing this market for the ISO is the full network model (FNM), and with it the transition to nodal pricing and a redesigned firm transmission rights (FTR) instrument. The ISO therefore proposes to implement the new market design in three phases:

- Phase 1 would begin on October 1, 2002, when the current FERC market mitigation rules are set to expire, with a subset of elements referred to as "October 1st Elements" designed to help provide continued market mitigation. For the most part the October 1st Elements are all elements of the Comprehensive Design, with slight modifications to account for expected conditions in the California markets and the fact that the substantive core of the new design

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30 The integrated unit commitment service (UCS) is separate from and has a different purpose than the Residual Unit Commitment (RUC). The UCS is integrated and performed simultaneously with the day ahead congestion management, energy, and ancillary services market, while the RUC is performed after the running of this market for reliability purposes, based on the ISO's load forecast. The RUC procedure is fully described in Section 5.5.

– the new forward congestion management and energy markets – will not be available at that time.[31]

- Phase 2 would occur in Spring 2003 and would establish the integrated forward congestion management, energy, ancillary services and unit commitment market using the ISO's current three-zone network model, but relaxing the market separation rule. Nodal pricing and the new FTR design would not be implemented at this time.
- Phase 3 would occur in Fall 2003 and would complete the implementation by installing the FNM and establishing nodal pricing and the new FTR design. To facilitate the transition to Phase 3, the ISO intends to have the FNM available for running in a test mode for several months prior to Phase 3 implementation, and to begin using the model to generate and publish nodal prices for informational purposes as soon as possible.

As soon as the FNM is developed and tested, the ISO would begin utilizing this FNM with all thermal physical constraints enforced. For voltage stability or transient stability constraints the model will include nomograms or interface flow limits as required by ISO Operating Procedures. The full network model will capture external loop flows by representing external transmission as an equivalent network.

A security constrained unit commitment optimization routine will be used to minimize the cost of meeting the scheduled demand and clearing economic demand bids subject to all transmission constraints and generator performance characteristics. Security constraints will be determined through off-line studies and security analysis of the transmission system with all clearances of transmission elements modeled. Provision will be made for accommodating a contingency list for those contingencies that may not have been taken into account in the off-line studies. The security constrained unit commitment will then identify and account for the most constraining contingency and the associated constraints.

Although the ISO would prefer that all Existing Transmission Contracts (ETCs) be converted to Firm Transmission Rights (FTRs), the ISO recognizes that full conversion of all ETCs may need to extend beyond the market implementation timetable proposed here. The ISO will therefore provide a method to continue to honor ETC rights. The continuation of ETC scheduling rights on a different time line from the ISO's congestion management raises the familiar problem of excessive curtailment of forward schedules, i.e., "phantom congestion." The ISO is therefore considering development of a recallable transmission service (RTS) product. At present RTS is an element under discussion in a settlement proceeding at FERC, and therefore the ISO can not say at this time when, how or even whether RTS will be implemented. Although an approach to RTS was proposed by the ISO in the context of the January 2001 Congestion Management Reform proposal, that approach will need to be reconsidered in the context of a simultaneous energy and congestion market based on locational marginal pricing at the nodal level.

5.2.2 ISO Proposal

5.2.2.1 Congestion Management, Energy Market, Nodal Prices

The ISO is proposing a forward congestion management (CM) procedure that adjusts generation and load (and import and export) schedules to clear congestion using an optimal power flow algorithm (OPF) and a Full Network Model (FNM) that includes all busses and

[31] Specific details of the October 1st Elements are not discussed in this document; the reader is referred to the document "Market Design 2002 – October 1st Elements" dated March 27, 2002, which is posted on the ISO web site.

transmission constraints as well as a network representation of the rest of the WSCC system to capture external loop flows. Using the FNM for CM does not, however, mean that we must use individual busses for all scheduling and settlement purposes. Rather, it will be possible to aggregate busses to create trading hubs to facilitate energy trading and load aggregations[32] to simplify load scheduling and settlement.

The proposed CM approach ensures that final schedules are feasible with respect to all transmission constraints as well as generator ramping and other performance constraints,[33] and eliminates the current distinction between inter-zonal and intra-zonal congestion. The last point deserves emphasis. A crucial assumption in the original zonal congestion management design of the ISO was that intra-zonal congestion would be infrequent and would have relatively small cost impacts. The idea was that a new zone would be created as soon as the frequency and cost of intra-zonal congestion exceeded a certain threshold, provided the congested interface defining the new zone could be managed through competitive bidding.

In practice, however, the distinction between inter-zonal and intra-zonal constraints and their management in separate congestion management steps have led to severe problems at various times in the ISO's history, and except for one instance (creation of ZP26) new zone creation has not offered a viable solution.[34] The ISO's experience has shown that not all intra-zonal problems are conducive to creation of a new zone, since a workable new zone must have a fairly simple physical topology, i.e., with a few well-defined constraining interfaces connecting it to the rest of the grid, and must have a competitive supply of bids on both sides of the defining constraints. In addition, some intra-zonal congestion is periodic in nature (e.g., seasonal), and some arises only on a temporary basis when transmission facilities are taken out of service.

Thus, in reality the "simplicity" of the zonal system only appears so because the complexity is assumed away, allowing market participants to ignore it in scheduling while the ISO must manage it by real time adjustments and periodic modifications to the rules to mitigate novel gaming strategies as they arise. The ISO believes that it will be far simpler, and more transparent, to design forward CM to be as consistent as possible with the real-time operating needs of the grid based on realistic expectations of actual daily grid conditions. In this regard eliminating the inter-zonal-intra-zonal distinction will increase the simplicity, transparency and accuracy of congestion management.

Another significant impact of the proposed CM approach is its implications for forward energy trading. The proposed CM approach will effectively create a day-ahead energy market that runs simultaneously with CM, as the next paragraph explains. Thus, while a separate PX-type energy market may still be desirable, the ISO does not see a need to create such a market given the energy trading inherent in CM.

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32 The ISO is proposing three types of load aggregations: (a) demand zones, which would coincide with utility distribution service territories (including municipals), and would recognize Path 15 by splitting the PG&E service territory into two demand zones; (b) load groups, i.e., subdivisions of the large PG&E and SCE demand zones; and (c) custom aggregations, to allow a retail service provider to aggregate those nodes where its customers are. These are discussed in detail in Section 5.8.

33 The proposed concept of feasibility does not, however, require that final schedules reflect actual levels of load and generation expected in real time. Any shortfall between final schedules and the ISO's load forecast is addressed by the ISO's day-ahead residual unit commitment, discussed below.

34 For example, ignoring intra-zonal constraints in establishing forward schedules has allowed "the DEC game," whereby suppliers can over-schedule a constrained intra-zonal pathway and then exercise local market power to receive a premium payment in real time to reduce their output to eliminate the overload.

The threshold design decision is to perform forward CM using a network model that is more complex than today's model of three radial zones. The same logic thus applies whether we are considering the model with 12 "Locational Pricing Areas (LPAs) as proposed in CMR, or one with all busses and constraints as proposed here, or something in between. The key point is that to manage congestion in such a model using a market-based approach with submitted bids – which reflect SCs' willingness to pay congestion charges rather than be curtailed – it will be impractical most of the time to keep each SC's schedule in balance. Rather, it will be necessary for the ISO to create energy trades, effectively treating adjustment bids as energy supply and demand bids. Alternatively, if the ISO does try to preserve the market separation rule, we will continually run out of adjustment bids and be forced to make pro rata curtailments.

In summary, under the proposed CM approach SCs will submit Energy/Adjustment Bids on their preferred generation and load schedules that will be used to clear congestion. As a result, balanced schedules for each individual SC become an option rather than a requirement. SCs who want to preserve physical bilateral contracts can submit high adjustment bids or no bids at all, thus becoming price takers for congestion charges, and can hedge their congestion risks with FTRs. The ISO is currently considering the implications of allowing a balanced schedule to declare a maximum congestion price it is willing to pay, so that congestion management would curtail it only when the relevant nodal price difference hits that maximum. In addition, under a simultaneous energy and congestion market design, SCs will be able to submit demand bids unmatched by supply, or supply bids unmatched by loads, and the simultaneous Energy/CM algorithm will execute all economic trades and clear the market in a manner that respects transmission and generator performance constraints. Thus bid-based CM using a complex network model ultimately undermines the rationale for a balanced schedule requirement, while still allowing physical bilateral scheduling for those SCs who wish to schedule in this manner.[35]

Thus the proposed forward CM approach addresses the need for a day-ahead energy market, as required by FERC in its December 19, 2001 order, since it accepts bids from unmatched loads and generators and clears all economic bids, subject to constraints. In so doing the forward CM approach results in nodal energy prices at each of the internal busses and intertie points, and forward congestion prices then become the difference between nodal energy prices. This will require some redesign of the existing FTR structure, as described in a later section.

5.2.2.2 Market Time Line

The Day-Ahead market timeline would be modified to eliminate the revised preferred iteration currently in place. With a formal DA energy market in which all economic energy trades are executed, there is no need for a second iteration. The ISO recommends leaving the deadline for receiving preferred energy bids and schedules at 10 A.M. The simultaneous market will likely take about one hour to run. The ISO would then publish final DA energy schedules between 11 A.M. and 12 Noon.

Following the integrated DA market, the ISO would perform the Residual Unit Commitment (RUC) procedure,[36] which is described fully in a later section. Since all ACAP resources will be

[35] With the introduction of an energy market, there may not be a need to receive inter-SC trades from SCs as the ISO does currently. Since all injections and ejections will be settled at the associated locational price and schedules need not be balanced, there is no need for the ISO to be aware of inter-SC trades. The ISO may want to continue to receive inter-SC trades, but they effectively become financial trading instruments. However, to facilitate the use of Existing Transmission Contract rights there may be a need to maintain the concept of an explicit resource transfer trade.

[36] In addition to the simultaneous market, which is based on SCs' preferred schedules and bids, the ISO would to perform the RUC procedure to commit the additional resources it expects to need to meet

required to bid into both the DA energy market and the RUC process, and since the RUC process will not be open to non-ACAP supply resources that may wish to participate, there will be no need to accept additional bids for the RUC process. The ISO will therefore run the DA RUC process between 12 Noon and 1 P.M. with the expectation that any additional ACAP capacity committed in the RUC can be published by 2 P.M.

5.2.2.3 Trading Hubs and Load Aggregations

As noted above, using the Full Network Model and generating nodal prices for forward CM does not require that all transactions be settled based on nodal prices. As is typical of other ISOs that utilize a FNM for forward CM, the ISO proposes to create various aggregations of nodes for the purpose of load scheduling and settlement and as trading hubs. SCs would be able to schedule loads at the nodal level or at the level of the "load aggregation" (which could be a demand zone (utility distribution service territory), a load group (a subdivision of a distribution service territory), or a custom aggregation based on a load serving entity's actual customer locations), and the ISO would allocate these loads to specific nodes using "bus load distribution factors" (BLDF, not to be confused with "power transfer distribution factors" also known as "shift factors") prior to running CM. The FNM would be used to run CM and the nodal prices would determine congestion costs, but then prices would be aggregated to the appropriate level for settlement purposes. A later section of this document describes these aggregations in detail.

5.2.2.4 Bid Mitigation for Local Market Power

The proposed forward CM approach also raises a need for forward bid mitigation for locational needs, to prevent the exercise of local market power in areas of the grid or across transmission pathways where there is not a competitive supply of bids. Thus far the ISO has either relied on RMR for forward management of local reliability, or has issued dispatch instructions to non-RMR resources as needed only in real time. The comprehensive design proposal therefore includes provisions for forward bid mitigation, discussed in a later section.

5.2.2.5 Phantom Congestion and Recallable Transmission Service

One persistent problem with the ISO's congestion management since the beginning has been so called "phantom congestion," a byproduct of the Existing Transmission Contract (ETC) rights that have existed since before ISO start-up. In some cases ETCs allow the rights holders to retain scheduling priority on designated transmission pathways up to 20 minutes before the start of the operating hour, which the ISO accommodates by fully removing ETC capacity from the CM process even though significant portions of that capacity will ultimately be unused by the rights holders and will become available in real time. As a result of reserving all ETC capacity the day ahead and hour ahead markets are frequently plagued by congestion that does not materialize in real time, hence the term "phantom."

Ideally the ISO would like to see all ETCs converted to FTRs or in some other way made consistent with ISO scheduling and congestion management procedures and timeline. If this is not possible initially, the ISO may consider offering recallable transmission service (RTS) on a day-ahead or perhaps hour-ahead basis after allocating firm transmission.

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the next day's load forecast. When the RUC is initially implemented on October 1, 2002, it would be open to receive bids from resources such as imports that are not required by a must offer obligation to bid into the RUC. Once a forward energy market is established, however, the RUC process will be limited to ACAP resources, based on the concept that all other non-ACAP resources will be able to bid their energy and capacity into the DA energy market.

RTS was discussed in detail in the January 2001 Congestion Management Reform proposal, which is available on the ISO web site. The RTS procedure the ISO is considering is to perform a second round of congestion management in the day ahead market, after all firm transmission has been allocated, utilizing the adjustment bids of those SCs whose day ahead schedules had been curtailed due to congestion and had indicated a desire to obtain RTS, and would allocate any reserved ETC capacity that was not scheduled by the ETC rights holders.

In June 2001 the Morgan Stanley Capital Group filed a complaint against the ISO regarding phantom congestion at FERC under section 206 of the Federal Power Act. The ISO is now engaged in settlement discussions centered on the details of implementing RTS to mitigate phantom congestion and thereby resolve the complaint. The final characteristics of RTS and whether RTS will be implemented at all currently hinge on the outcome – whether through settlement or litigation – of the Morgan Stanley complaint. The ISO will continue to participate in the proceedings to define RTS and will propose appropriate revisions to the comprehensive market design should they be necessary.

5.2.2.6 Determination of Losses

Some thought must be given to how losses are calculated in a simultaneous energy market that is using locational marginal prices. The ISO is considering an approach similar to the New York ISO's approach in which marginal prices with and without losses are produced.

One approach is to continue using the GMM/TMM procedure used today. If this approach is used the GMM/TMM will continue to be applied to generators and imports. This approach will continue to make generators responsible for the losses associated with delivery to system load. Under this paradigm an entity that has a generator and a load at the same bus will be responsible for losses even though the generator is delivering to the same bus. This approach will be consistent if a DC-OPF is utilized for resolving congestion management but would require an AC solution to determine network loss sensitivity for each generator.

Another approach to consider is to incorporate the losses into the locational marginal prices. In the New York ISO an AC-OPF is used for the simultaneous optimized market. From this AC-OPF, the locational marginal prices are broken into three components, a reference energy price, a marginal loss adder and a congestion adder. With this approach an entity that has a generator serving a load at the same bus would not incur a loss charge because the settlements for the load and generator are the same locational price (LBMP).

Lastly, PJM utilizes a very simplified approach in which load is charged a 3 percent loss adder to the locational marginal price during on-peak hours and a 2.5 percent loss adder in off-peak hours.

5.2.3 Phasing of Implementation

5.2.3.1 Overview

The purpose of the present section is to describe the ISO's proposed phasing of the implementation of the integrated forward markets and the full network model.

The ISO anticipates that implementation would occur in three phases:

1. Phase 1 has a target date of October 1, 2002, and includes the design elements described in the separate document titled "October 1st Elements."

2. Phase 2 has a target date of Spring 2003, and would include most of the comprehensive design proposal except for the full network model and the features that require that model, i.e., nodal energy pricing and the new FTR design.
3. Phase 3 has a target date of Fall 2003, and would complete the comprehensive design with the full implementation of the full network model, using a state estimator, and the redesign of FTRs.

During the 1st quarter of 2003, the ISO anticipates having the necessary software ready to support the changes associated with the integrated day ahead (DA) market, and would implement these changes as part of Phase 2 using the existing three-zone network model. These changes would replace the separate congestion management and ancillary service market with a simultaneous energy, congestion, ancillary service and unit commitment market. The Market Separation Rule and the balanced schedule requirement would be eliminated so that SCs could submit unbalanced supply and demand bids.

Since the ISO will be running an integrated DA energy and congestion management market once Phase 2 is implemented, the design does not recommend running a second iteration the way the ISO does today.

Since the full network model is implemented only in Phase 3 the ISO proposes to manage intra-zonal congestion through the end of Phase 2 by calculating, publishing and enforcing forward scheduling limits on generators within congested areas of the grid, to prevent the establishment of infeasible forward schedules in these areas. The ISO is currently working with stakeholders to develop a viable alternative to the approach proposed in Amendment 42, such as an approach that will take into account market-based bids with appropriate market power mitigation measures. Depending on the outcome of this process the ISO will submit its preferred interim intra-zonal congestion management approach in a separate filing in the near future.

Finally, until the FNM and nodal pricing are implemented, it will not be necessary for the ISO to modify the existing design of FTRs nor the present granularity of load scheduling and settlement. With regard to FTRs, the ISO proposes to conduct a transitional release of FTRs under the current design that would be effective for roughly six to nine months, from April 1, 2003 up to a Phase 3 implementation date to be specified in fourth quarter 2003.

Details of the proposed implementation phases are described in the following table.

5.2.3.2 Proposed Implementation Phases

In the following table, key differences between consecutive phases are shown in bold type.

DA Market Feature	Today	Phase 1 October 1, 2002	Phase 2 Spring 2003	Phase 3 Fall 2003
Forward Energy Market	Bilateral only Market Separation rule enforced	**Bilateral only** **Market Separation Rule enforced**	**Bilateral augmented by ISO centralized** **Market Separation eliminated** Bid screens and Automatic Mitigation Procedures (AMP) **Zonal energy prices** Feasible ramps enforced for generating units and net interchange	Bilateral augmented by ISO centralized Market Separation eliminated Bid screens and Automatic Mitigation Procedures (AMP) **Nodal energy prices** Feasible ramps enforced for generating units and net interchange

Congestion Management	Zonal Market Separation Voluntary adjustment bids Feasible schedules not enforced No forward management of intra-zonal congestion Existing CONG software used RMR used for local area reliability	Zonal **Market Separation** Voluntary adjustment bids **Forward intra-zonal congestion management based on day-ahead scheduling limits in congested areas** Existing CONG software used RMR used for local area reliability	**Zonal** Simultaneous with energy market **No Market Separation** Forward intra-zonal congestion management based on day-ahead scheduling limits in congested areas Use TCUC software with simplified zonal model Single iteration RMR used for local area reliability	**Nodal** Simultaneous with energy market No Market Separation **No distinction between inter-zonal and intra-zonal congestion** **Schedules will be feasible based on scheduled load** Use TCUC software with full-network model Single iteration Once ACAP is fully effective, use ACAP resources and RUC for local reliability
Ancillary Services	Requirements based on 100% ISO load forecast with flexibility to shift to HA market. Sequential capacity markets for Reg-up, Spin, Non-spin, Replacement. Rational Buyer used to minimize cost. Cost of energy not considered when purchasing capacity **Different energy curve may be bid with each service.**	Requirements based on 100% ISO load forecast with flexibility to shift to HA market. **Sequential capacity markets for Reg-up, Spin, Non-spin, Replacement**. Rational Buyer used to minimize cost. **Cost of energy not considered when purchasing capacity.** **Single energy curve across all services**	Requirements based on 100% ISO load forecast with flexibility to shift to HA or RT market. **Simultaneous capacity market for regulation, spin and non-spin.** **Replacement reserve not necessary.** **Energy bids used to evaluate opportunity cost in selection process.** Capacity bid reflects the bidder's minimum opportunity cost needed to provide capacity. **Transmission constraints will be enforced on area basis.**	Requirements based on 100% ISO load forecast with flexibility to shift to HA or RT market. Simultaneous capacity market for regulation, spin and non-spin. Replacement reserve not necessary. Energy bids used to evaluate opportunity cost in selection process. Capacity bid reflects the bidder's minimum opportunity cost needed to provide capacity. **Capacity is procured subject to transmission constraints (will require technical development)**
Voluntary Unit Commitment Service (UCS) integrated with congestion, and Residual Unit Commitment (RUC)	No UCS RUC runs after final DA schedule is established RUC relies on must-offer rule. Start-up, minimum load and incremental energy cost considered. Expected level of interchange is estimated based on recent history Uses separate TCUC software after DA congestion market.	**No UCS** RUC runs after final DA schedule is established **RUC relies on modified must-offer.** A capacity payment is proposed to compensate committed capacity and allow ISO to reserve it to serve in-state load. Start-up, minimum load and energy bid curves considered. **Ties may bid in and be committed during RUC process** Energy procured in RUC will be limited such that total energy does not exceed 95% of ISO forecast Uses separate TCUC software after DA congestion market.	**Integrated UCS using TCUC, to meet scheduled load** RUC runs after final DA schedule is established **Until ACAP is effective, RUC relies on modified must-offer, including capacity payment as established for 10/1/02.** Start-up, minimum load and energy bid curves considered. **Ties may bid into UCS, but only ACAP ties may bid into RUC once DA Energy market is implemented.** RUC is to meet 100% ISO forecast load, after adjusting for expected load served in HA or by Governmental Entities Energy procured in RUC will be limited such that	Integrated UCS using TCUC, to meet scheduled load RUC runs after final DA schedule is established Until ACAP is effective, RUC relies on modified must-offer, including capacity payment as established for 10/1/02. Start-up, minimum load and energy bid curves considered. Ties may bid into UCS, but only ACAP ties may bid into RUC. RUC is to meet 100% ISO forecast load, after adjusting for expected load served in HA or by Governmental Entities Energy procured in RUC will be limited such that total energy does not exceed 95% of ISO

		Bid screens and Automatic Mitigation Procedures (AMP) are applied.	total energy does not exceed 95% of ISO forecast. **UCS and RUC will meet zonal feasibility requirements.** Bid screens and Automatic Mitigation Procedures (AMP)	forecast. **UCS and RUC will meet full-network model feasibility.** Bid screens and Automatic Mitigation Procedures (AMP)
Losses	Scaled marginal loss GMM/TMM calculated based on sensitivity analysis. Congestion not affected by losses	Scaled marginal loss GMM/TMM calculated based on sensitivity analysis. **Congestion not affected by losses.**	**Marginal losses incorporated into simultaneous energy and congestion market. (NYISO approach)**	Marginal losses incorporated into simultaneous energy and congestion market. (NYISO approach)
Inter-SC trades	Trades used to balance SC portfolios. Trades not adjusted in CONG. Adjustable trades via explicit resource transfer.	Trades used to balance SC portfolios. Trades not adjusted in CONG. Adjustable trades via explicit resource transfer.	**No impact on congestion with elimination of Market Separation** Non-resource specific trades can be declared but would only have impact in settlement. Considered a transfer energy to be settled at zonal price of declared trade. Trades do not affect congestion results. Consider if trades can be conducted even after DA market. Explicit resource trades can be used to submit a balanced bi-lateral that is considered price-taker for congestion.	No impact on congestion with elimination of Market Separation Non-resource specific trades can be declared but would only have impact in settlement. Considered a transfer energy to be settled at zonal price of declared trade. Trades do not affect congestion results. Consider if trades can be conducted even after DA market. Explicit resource trades can be used to submit a balanced bi-lateral schedule that is considered price-taker for congestion.

5.2.4 Alternatives Considered

5.2.4.1 Network Model for Congestion Management

The only significant alternative the ISO considered in developing this proposal was the approach developed during the ISO's Congestion Management Reform (CMR) effort in year 2000. That proposal called for the creation of 15-20 Locational Pricing Areas (LPAs), based on the Local Reliability Areas (LRAs) of the ISO Control Area that are managed operationally via operating nomograms. The LPA approach is essentially an extension of the existing zonal approach, but would have a larger number of zones, some of which would be interconnected by parallel paths and loop flows. The LPA approach could also be seen as Locational Marginal Pricing (LMP) with the locations being LPAs rather than nodes. With the LPA approach, it would still be necessary to eliminate Market Separation and the balanced schedule requirement, since these constraints would inevitably lead to insufficiency of adjustment bids in a looped network model with 15-20 zones.

The ISO rejected the LPA approach since it would not solve the fundamental problem of ensuring that forward schedules are fully feasible and that forward allocation and pricing of scarce transmission capacity is fully consistent with real time power flows. It would still retain the distinction between intra-zonal and inter-zonal congestion, and would manage these in two separate steps. Finally, the LPA approach would rely on creating new zones, which presents some serious engineering problems in certain concentrated load areas of the grid. For example, the zone concept would be practically impossible to apply in the Greater Bay Area due to the complexity of the network within that area and its linkages to the rest of the grid.

5.2.4.2 Forward Energy Market

Early in the MD02 effort the ISO considered creating a separate day ahead energy market similar to the former California Power Exchange (PX). As the design of forward congestion management progressed and it was realized that simultaneous congestion management and energy trading would be the preferred design, the ISO concluded that there was no reason for it to create an additional, separate energy market.

5.2.4.3 Phasing of Implementation

The main alternative the ISO considered with regard to phasing was whether to implement the integrated DA market structure prior to having the full network model (FNM) operational. Without the FNM the new market structure would not be able to achieve all its objectives, since the ISO would be limited to the existing three-zone network model and would still have to perform separate management of intra-zonal congestion as a separate procedure. The ISO believes, however, that overall it would be advantageous to implement the new market design even without the FNM, since it would provide the much needed day ahead energy market as well as an opportunity to gain experience with the integrated market structure prior to adding the complexity of the FNM and nodal pricing.

5.2.5 Conformance with FERC Standard Market Design

FERC Standard Market Design	*ISO Proposal*
Locational Marginal Pricing (LMP)	Yes
Bid-based, security constrained	Yes
Simultaneous TX/Energy/AS	Yes
Bid-based, security constrained	Yes
Voluntary	Yes
Accommodates Bilaterals and Self-Schedules.	Yes
Multi-part Bidding	Yes
Voluntary Balanced Schedules	Yes
Bidding Limitations	Yes
LMP – nodal	Yes
Voluntary Trading Hubs	Yes
Clearing Price Auction	Yes
Uplift Payment for Generators	Yes
Accommodates Demand Bidding	Yes
Accommodates Energy-limited, Intermittent Resources	Yes

5.3 Firm Transmission Rights (FTRs)

5.3.1 Introduction

Certain changes to the design of Firm Transmission Rights (FTRs) are needed in conjunction with the forward congestion management (CM) design described above. Specifically, under a forward CM design that is based on Locational Marginal Pricing (LMP) and uses a full network model (FNM), a different type of FTR design is needed to enable market participants to hedge congestion risks.

For example, today's FTRs are path and direction specific, and are used in a fully radial fashion consistent with the ISO's three-zone network model used for forward inter-zonal congestion management. This means that a schedule across an inter-zonal pathway is assumed to flow completely over that pathway, assuming away any loop flows outside the ISO control area. In contrast, under the proposed LMP approach, forward schedules are assessed for their flows throughout the grid, including external loops, rather than focusing only on specific pathways. This approach calls for a "point-to-point" FTR[37] as the primary type of FTR, to be supplemented at a later date by the more familiar path-specific or "flowgate" type FTR for some pathways.

In conjunction with the point-to-point FTR model, the ISO must run a "simultaneous feasibility" assessment to determine the quantities of FTRs that can be released via the auction process. This assessment uses a power flow model to combine all parties' desired FTRs and their bids for these FTRs, and then issues the set of FTRs that maximizes auction revenues subject to all FTRs being simultaneously feasible under assumed system conditions. In this way FTRs are issued to the bidders who value them the most.

Another significant change to FTR design is to utilize an "obligations" approach as the primary design, rather than today's "options" approach. Obligations FTRs allow a more complete and more efficient release of rights to the grid than the options approach. In the options approach, the quantities of FTRs that can be released are limited by the physical transfer capability of the grid. In contrast, in the obligations approach the quantities released can exceed the physical limits of the grid whenever counter-flows are created, as long as the simultaneous flows of all FTRs are within the physical limits. For this approach to work, however, a FTR holder who does not schedule in accordance with their FTRs must pay congestion charges when congestion is in the opposite direction of their FTRs, because their failure to schedule had adverse impacts on grid users trying to move power in the opposite direction.

In addition, the LMP design will entail more geographically granular scheduling and settlement of loads than is done today, and will thus subject loads to greater locational price variation when there is congestion. It is appropriate therefore to revise the current allocation method of FTRs and FTR auction revenues to provide loads a hedge against congestion costs, consistent with direction recently provided by FERC in its Standard Market Design Working Paper and Options Paper.

[37] As discussed in greater detail later in this section and in Section 5.8, for the purpose of defining a transmission right a "point" may be an individual node of the full network model or an aggregation of nodes to form a trading hub or a load aggregation. FERC's Standard Market Design papers typically use the term "source-to-sink" for this type of FTRs.

One further design issue that does not yet have a satisfactory solution in this proposal relates to Existing Transmission Contracts (ETCs). Since the beginning of ISO operation, ETC holders have been able to reserve transmission capacity beyond the close of the day ahead market, up through the running of the hour ahead market and nearly up to the start of the Operating Hour, even though the ETC holders may not actually use all this capacity in real time. This provision for ETCs forces the ISO to perform congestion management as if all the ETC capacity is fully scheduled, thus frequently creating artificial or “phantom” congestion in the forward markets which can lead to extremely inefficient allocation of the grid. The ISO’s ultimate objective in redesigning congestion management is therefore to perform all transmission allocation through a single CM and FTR system, according to a single set of rules and a common scheduling time line. To achieve this objective will require converting ETCs to FTRs and eliminating the need for separate scheduling provisions for ETCs. FERC’s recent Options Paper on the Standard Market Design expresses clear concern about incompatibilities between ETCs and the LMP approach, and supports the objective of eventually treating all grid users according to a common Open Access Transmission Tariff.

5.3.2 ISO Proposal

5.3.2.1 Summary of Proposal

To create an FTR instrument that complements the proposed LMP congestion management approach, the ISO proposes the following changes to the design of FTRs:

1. The nodal energy prices generated by forward congestion management (CM) would be the reference for congestion charges; thus the congestion charge between two nodes would be the difference in the respective nodal prices.
2. To allow hedging of congestion risks to be as complete as possible under the LMP approach, market participants would be able to obtain “point-to-point” FTRs, where a “point” may be a single node or an aggregation of nodes, such as a trading hub or a load group.[38] As a shorthand in this paper we will call this a “point-to-point FTR” system (PTP-FTR), with the understanding that points may be nodes or aggregations of nodes. The ISO is also assessing whether there is a need to create path-specific or “flowgate” rights in addition to the point-to-point FTRs, and whether the potential benefits of adding flowgate rights justify the additional complexity of having the two types.
3. Physical scheduling priority of today’s FTRs can be preserved under a point-to-point rights system. To use the FTRs in this way the SC would need to attach them to a balanced schedule between the two relevant points, in the same direction as the FTRs. Scheduling priority would apply to the day ahead market only, so that scheduling rights not exercised by the FTR holder would not result in capacity being withheld from the market.
4. FTR financial rights would be fully paid or charged in the day ahead market (i.e., based on day-ahead locational prices and/or flowgate congestion prices); there would not be any financial rights applicable to the hour ahead and real time markets.

[38] The ISO will establish initial trading hubs to coincide with today’s three zones, i.e., NP15, ZP26, and SP15. If additional new hubs are needed to facilitate energy trading, creating them is a fairly simple matter since hubs can be any commercially convenient aggregations of nodes; they do not need to be based on major constraints or other structural features of the grid like today’s zones are. Load aggregations for scheduling and settling load are described below and in Section 5.8.

5. The primary form of the new FTRs would be what are known as "obligations," which impose a cost on the FTR holder when congestion is in the opposite direction of the FTR, in contrast to "options" which impose no cost when congestion is in the opposite direction. The ISO recognizes that the obligations model would be new to California, and that several parties have expressed preference for the options model. The obligations model offers significant advantages, however, including: (1) the obligations model allows larger quantities of FTRs to be released and offers more complete risk-management capabilities; (2) the obligations model creates strong incentives for participants to buy FTRs that reflect their intended use of the transmission grid for scheduling; and (3) the methodology for running a simultaneous feasibility assessment of options-only or combined options and obligations FTRs has yet to be fully developed, tested and used by a functioning ISO or other control area operator, while the obligations-only model is a tried and proven approach. By starting with obligations FTRs, the ISO does not intend to preclude creating options-type FTRs at a later time as the need is demonstrated and the required methodology is developed and proven. Such staging of FTR design is consistent with FERC's Standard Market Design, since FERC recognizes that only the obligations model is fully developed and proven at this time.
6. The ISO recommends that FTRs be a full hedge against congestion (i.e., one MW FTR is entitled to one MW congestion payment or charge), rather than a partial hedge (one MW FTR is entitled to a fixed share of congestion revenues which may not equal the locational price difference being hedged when there are changes in network conditions). In any given hour, however, the amount of congestion revenues may not exactly equal the settlement of all FTRs under a full hedge design. In order to maintain the full hedge, the ISO proposes to create a balancing account that accumulates the excess revenues generated in hours when total congestion charges exceed required FTR payments, and then uses these revenues to keep FTR holders whole in hours when congestion charges are inadequate.
7. The ISO proposes to release FTRs based on three different term lengths: long-term (3-year duration), medium-term (1-year duration), and short-term (monthly duration). The quantities of the first two releases would be based on a percentage (30% for the 3-year FTRs and 45% for the 1-year FTRs) of the lowest actual level of Available Transmission Capacity in the most recent 12 months before the auction, while the monthly quantities would be determined based on expected system conditions for the coming month.
8. To enable loads to hedge the risks associated with congestion charges[39] the ISO proposes to provide an initial allocation of FTRs to load-serving entities (LSEs) based on the historic quantities and geographic distribution of their loads and supply resources, as is done in the PJM ISO. The ISO would then run an FTR auction to allocate any transmission capacity that remained after LSEs and ETC holders received their shares (allocation to ETC holders is discussed below). LSEs that receive an initial allocation or FTRs could participate in this auction as buyers or sellers, and the auction revenues generated by the sale of LSE-held FTRs would be paid to the selling LSEs.
9. FTR auction revenues generated by the sale of any un-allocated capacity would be paid to Participating Transmission Owners (PTOs) to be applied as an offset to the Transmission Access Charge (TAC).

[39] As discussed in Section 5.8, the ISO proposes to require loads to be scheduled and settled initially at a level of geographic granularity at least as fine as today's demand zones. The requirement would shift to the finer load group level as soon as technically feasible, with allowance for loads to select the nodal level or a custom aggregation. See Section 5.8 for details.

10. Ideally all ETCs would be converted to the new FTRs in such a way that the holders of the existing ETC rights would have to schedule in accord with the ISO's scheduling procedures and time line, and these procedures would offer an adequate "tool kit" to enable ETC rights holders as far as possible to achieve the same management of risk that their current rights provide. The ISO recognizes, however, that some quantity of ETCs may continue to exist in their present form at the time the ISO implements the comprehensive design.

11. Based on the design features and other considerations described above, the ISO proposes to perform the following sequence of steps in allocating transmission capacity to (1) ETCs that do not convert to FTRs; (2) ETCs that do convert to FTRs; (3) LSEs; and (4) market participants who wish to bid for FTRs. Each step requires the ISO to run a simultaneous feasibility assessment on the relevant set of desired rights, after fixing the allocation of rights that resulted from the previous step.

    (a) Step 1. Allocation of transmission capacity to non-converted ETCs. The ISO proposes to allocate transmission capacity to non-converted ETCs based on their historic usage patterns rather than their nominal contract rights. The ISO is concerned that, due to the way ETC rights were historically allocated and have operated in practice, allocating transmission capacity under the LMP system to all ETCs based on nominal contract quantities would have too severe an impact on the ISO's management of the remaining capacity of the grid. In particular, extremely small quantities of capacity would remain for New Firm Use (NFU) in some areas of the grid, and the frequencies and levels of phantom congestion would be more severe than today.

        In order to perform this allocation, the ISO would have to obtain from the ETC holder a description of the holder's normal use of the grid under the ETC rights, with specific quantities of load and generation at each location for each hour of a representative day.[40] The ISO would then perform a simultaneous feasibility assessment of the grid use patterns of all non-converted ETCs to determine the collective impact on the grid of the entire set of ETCs. In areas where all grid use patterns are not simultaneously feasible the algorithm would have to make pro rata curtailments, so that the end result would be simultaneously feasible.

        In performing the simultaneous feasibility for this step the ISO would assume that all ETCs are options rather than obligations, consistent with the way ETCs actually work. Because ETCs are options, the effect of honoring them prior to allocating transmission to other users is to effectively reduce the transfer capacity of the grid by removing the ETC capacity completely from the ISO's congestion management procedure. With obligations-type rights, in contrast, the impact of the rights on transfer capacity can be offset by counter-flow schedules, so that the allocated rights have no absolute effect on the availability of capacity for use by others. As noted above, the ISO would need to develop the simultaneous feasibility algorithm for options-type transmission rights in order to perform this step.

    (b) Step 2. Allocation of FTRs to converted ETCs. With the capacity allocated to non-converted ETCs removed from further availability, the ISO would turn to the set of ETCs that had converted to FTRs and assess their simultaneous feasibility, this time using the obligations approach. As in the previous step, the ETC holders would have to provide their normal grid use patterns. The ISO's intent in using the obligations model in this step is that there should be no real differences between converted ETC FTRs

[40] Seasonal variations in grid use by ETCs could be accommodated by performing this assessment on a monthly or seasonal basis, rather than just once for the entire year.

("E-FTRs"), the FTRs allocated to LSEs ("LSE-FTRs"), and FTRs auctioned to market participants in the general auction. Therefore, since the ISO proposes to start with an obligations FTR design initially, the E-FTRs must be consistent with the FTRs used by the rest of the market.

(c) Step 3. Allocation of FTRs to LSEs. For this step the LSEs would have to provide the grid usage patterns they normally rely upon to serve their loads, and again the ISO would run an obligations-type simultaneous feasibility. The ETC capacity allocated in step 1 would not be available in this run, but the E-FTR capacity awarded in step 2 would be put into the mix in order to allow for the effect of counter-flows under the obligations model. In the event that not everything is simultaneously feasible the ISO would presumably curtail LSE-FTR requests and preserve E-FTRs as far as possible, to provide E-FTRs a higher degree of certainty of receiving their desired FTRs, as a benefit for converting their ETCs to FTRs. Alternatively, if E-FTRs and LSE-FTRs are given the same level of priority, steps 2 and 3 could be combined into a single step.

(d) Step 4. Allocation of remaining FTRs through an FTR auction. Unlike the previous three steps where no bids were involved, in this step market participants would bid to buy the FTRs they wish to obtain, and E-FTR and LSE-FTR holders would offer to sell some of their FTRs if they wish to do so. This time the ISO would run a bid-based obligations-type simultaneous feasibility, protecting those E-FTRs and LSE-FTRs that were not offered for sale, executing trades between buyers and sellers and awarding the remaining available capacity to maximize the auction proceeds. Sellers of E-FTRs and LSE-FTRs would receive the auction proceeds for the FTRs they sold, and the remaining auction revenues would be allocated to the relevant PTOs.

As simultaneous feasibility algorithms are developed and proven to allow combined options and obligations FTR designs, the ISO will incorporate this approach into steps 2 through 4.

5.3.2.2 FTR Design Concepts and Terminology

5.3.2.2.1 Financial Rights

The FTR is a financial hedge against congestion. Congestion is caused by network constraints that are "binding" by preventing more efficient market outcomes, thereby imposing a cost on Market Participants. The congestion cost materializes in congestion revenue collected by the ISO for performing congestion management. The FTR holder is paid a portion of the congestion revenue, which may be used to offset the cost of congestion.

In the ISO's current congestion management process, which preserves balanced schedules, congestion charges are explicit and are assessed on schedules that contribute to congestion, whereas counter-flow schedules that alleviate congestion are paid instead. The net of all congestion charges and payments for a given binding constraint constitutes the congestion revenue from that constraint. This congestion revenue is paid to the holders of FTRs on that constraint in proportion to their FTR ownership. Any remaining revenue for residual transmission capacity not under FTR ownership is paid to the Participating Transmission Owners (PTOs) in proportion to their ownership of the transmission facilities associated with the constraint.

In the ISO's proposed simultaneous congestion and energy market based on LMP, where schedules are not necessarily balanced, congestion costs are implicit and manifest in locational energy price differences across the network. Congestion revenue is collected by the ISO for each binding constraint through the settlement of day ahead scheduled energy at the various locational energy prices. This congestion revenue is paid to FTR holders to serve as a hedge against the congestion cost of a balanced portion of their schedule.

The FTR is a financial tool for the forward scheduling markets. In theory, the financial right of the FTR could be extended to real time to provide a hedge against real-time congestion. The real-time market is a spot market for energy and transmission, and market participants may arbitrage their sales and purchases among the forward and real-time markets. Based on recent experience, however, the ISO wants to discourage parties from trading large volumes in real time, and allowing FTRs to be used for hedging against real-time congestion costs would not be aligned with this objective. Moreover, settlement support for real-time FTRs would be complex because real-time energy is priced and settled in 10-minute intervals. The ISO therefore recommends that the FTR financial right apply only in the forward markets.

FTRs can be defined as either (a) “flowgate” rights (FGRs), i.e., path-based rights on specific network constraints (like oriented network branches, transmission interfaces or flowgates, and nomograms), or (b) “point-to-point rights” (PTP-FTRs) for power transfers between network locations. In case (a) the FTR provides a hedge against congestion on the specific constraint. In case (b) the FTR provides a hedge against all network congestion for power transfer from the origin (source) to the destination (sink).

With regard to PTP-FTRs, sources and sinks may be actual network nodes or an aggregation of nodes such as trading hubs. Hubs are price aggregation points where the hub price is defined as the load-weighted average of the nodal prices of all nodes in the hub. Hubs may have a hierarchical structure, so that a hub may be an aggregation of several other hubs. Hubs are most useful when they are consistent with hierarchical load aggregation models. In this case, a hub sink would be equivalent to an equal amount of aggregate load distributed to its underlying load nodes via the relevant Bus Load Distribution Factors (BLDFs).

FTRs (both the FGR and the PTP-FTR types) can be defined as obligations or options. For example, for a PTP-FTR obligation of 1 MW, the FTR holder would receive the locational price difference between the sink and the source, even if it were negative. (In the latter case, the FTR payment is actually a charge to the FTR holder.) Such rights are called obligations because to offset the FTR charge (with congestion revenue) the FTR holder must schedule in accordance with the FTR. This schedule provides counter-flow transmission capacity that has been sold as FTRs in the opposite direction. If the FTR holder fails to schedule in accordance with the FTR it may cause congestion in the opposite direction and would have a negative impact on the holder of the opposite FTR, which is the rationale for the charges associated with obligation FTRs.

Option FTRs, in contrast, have financial consequences in one direction only, so that FTR holders in the direction opposite the congestion are neither paid nor charged. Holders of option FTR thus have the ability not to schedule without running the risk of being subject to congestion charges in the opposite direction. Unlike FTR obligations, FTR options do not create transmission capacity sold as FTRs in the counter-flow direction. Therefore, FTR release is more conservative for options than for obligations because it is limited by the actual physical capacity of the specific path.

This being said, it is theoretically possible to create mixed systems having both options and obligations FGRs and options and obligations PTP-FTRs. The ISO is proposing to begin with obligations-type PTP-FTRs because this methodology has been successfully demonstrated and is in use by other ISOs. The ISO will consider expanding the FTR design to include some of the other types as the need and the feasibility of these other types are demonstrated.

PTP rights are mathematically equivalent to portfolios of FGRs on all network branches for an amount determined by the respective Power Transfer Distribution Factors (PTDFs) of the network model used in the primary FTR auction. The FGR payments for each binding constraint are calculated as the product of the FGR ownership on that constraint and its shadow price. FGRs are a full hedge unless the Available Transmission Capacity (ATC) of a flowgate is reduced below the transmission capacity that was released for FGRs on that flowgate in the primary auction. Then, the FGRs would be reduced pro rata. PTP rights are affected not only by changes to ATC, but also by changes to the PTDFs. If the network model used in congestion management is identical to the network model used in the primary FTR auction, i.e., when the PTDFs are the same, all FTRs are a full hedge. Otherwise, the payment to a PTP right may not equal the locational price difference between its sink and its source (see the FTR Appendix to this document for examples).

The discussion in the previous paragraph lies behind the statement that FGRs have a higher "deliverability" than PTP-FTRs. The reason for this is that the release of FGRs for a particular path is limited by the rated transfer capacity of the path and therefore does not depend on the scheduling behavior of other FTR holders to be feasible. In contrast, the release of PTP-FTRs is based on a simultaneous feasibility algorithm (a power flow) that assesses the transfer capacity of the whole set of available FTRs over the entire network under assumed network conditions (usually, all lines in service). The down side to FGRs, however, is that users must obtain different combinations of FGRs to hedge their risks under different congestion patterns.

The ISO recommends that FTRs be a full hedge against congestion (1 MW FTR corresponds to 1 MW congestion payment or charge), rather than a partial hedge (1 MW FTR corresponds to a fixed share of congestion revenues which may not equal the locational price difference being hedged when there are changes in network conditions). Therefore the ISO proposes to create side payments to FTR holders to compensate for congestion revenue shortfalls resulting from changing network conditions. Since there can also be excess revenues at certain times, these side payments can be recovered through a balancing account which compensates revenue shortfalls from the funds accumulated during hours of congestion revenue excess.

5.3.2.2.2 Physical Rights

FTRs may also be defined as physical transmission rights. In this case, however, for efficient use of the transmission network, a mandatory release mechanism is necessary so that failure of the FTR holder to exercise its physical scheduling right does not result in transmission capacity being withheld from the congestion market. Therefore, the physical right of FTRs should only be valid in the day ahead market and it should expire afterwards.

The physical right amounts to scheduling priority in the day ahead market, i.e., priority against being curtailed for congestion management. Since energy schedules without bids (i.e., price takers for congestion costs) have scheduling priority anyway, FTR schedules without bids should be given a higher scheduling priority than other price takers.

Physical rights can be an aspect of both FGRs and PTP-FTRs. In the case of PTP-FTRs, the most useful physical rights will be node-to-node. While it is possible to grant physical rights for node-to-hub FTRs, such rights may not coincide with the actual scheduling pattern of the FTR holder and therefore may not be very useful. With a node-to-hub right, the hub sink is equivalent to distributing the load over all the nodes of the hub according to the BLDFs that were used in the primary FTR auction. This would be useful to the FTR holder only if its actual load pattern had the same distribution.

5.3.2.3 FTR Use For Ancillary Services

In a forward market where energy and Ancillary Services (AS) are procured simultaneously, generating capacity is allocated optimally between energy and AS awards. To ensure that purchased AS capacity will be deliverable in real time, one approach would to be reserve some transmission capacity for AS, thus contributing to congestion along with scheduled energy flows. The simplest version of this idea would be to reserve transmission capacity only for AS imports across inter-ties, and to assess congestion charges for transmission capacity reservation to AS importers while using a single marginal AS price per procurement region. Under this approach, FTRs could provide a financial hedge against the cost of this reservation. In addition, in the day ahead market only, FTRs could also be used to provide selection priority for AS self-provision over other AS self-providers, and also for AS price takers (bidding $0/MW) over other AS price-takers. This feature does not appear very useful, however, and it would increase implementation complexity, hence it is not recommended at this time.

An alternative approach entirely would be not to reserve transmission capacity for AS, but instead to establish minimum AS requirements at various locations within the grid, in such a manner as to minimize the potential impact of congestion on the deliverability of energy from AS capacity. This is the ISO's preferred approach, and therefore the question of using FTRs to schedule AS becomes moot.

5.3.2.4 FTR Term and Release

Note: The following discussion is framed in terms of specific transmission paths for the sake of simplicity. The principles apply equally to a simultaneous feasibility assessment for the purpose of issuing PTP-FTRs.

The ISO proposes to release FTRs on a long-term (3-year), mid-term (1-year) and short-term (monthly) basis. The total amount would equal 100% of ATC, based on the lowest ATC over the previous 12 months. The ATC would be based on the difference between the applicable WSCC path rating and the allocated ETC rights. Absent a WSCC path rating, the N–1 contingency path rating will be used. The total amount would be distributed 30% long-term, 45% mid-term, and the remainder monthly. The quantity to be auctioned on a long-term and mid-term basis would be determined from historical data (the total of the 75% comes from the lowest ATC over the previous 12 months), while the monthly quantities would be determined based on forecasted availability reflecting, among other things, scheduled outages and seasonal factors.

For example, assume that a network branch AB has a path rating (or a total transfer capability when there is no path rating) of 1000 MW and an ETC level of 400 MW at the 1000 MW capability. In addition, assume that the lowest ATC (TTC – ETC) for the previous 12 months was 500 MW. Under the proposed design, the ISO would auction long-term and mid-term FTRs based on 30% and 45%, respectively, of the available ATC, which, in the above example would be:

> 500 MW Lowest ATC x 30% = 150 MW Long-Term (3-year) FTRs
>
> 500 MW Lowest ATC x 45% = 225 MW Mid-Term (1-year) FTRs

On a monthly basis, all of the remaining capacity would be auctioned based on forecasted system conditions. Continuing with the above example, assume for month X there is a minimum monthly TTC of 900 MW that is based on a forecast of planned outages and derates, an ETC level of 350 MW at the 900 MW TTC, and long-term and mid-term FTRs of 375 MW. At 15 days before the beginning of month X the ISO would auction an amount of FTRs equal to:

> 900 MW of TTC – (350 MW of ETC + 375 MW of long and mid-term FTRs) = 175 MW of monthly FTRs.

For the remainder of the month, where the TTC is above 900 MW but less than 1000 MW, the ISO will release the residual ATC capacity as New Firm Use (NFU) capacity in the Day-Ahead, Hour-Ahead and Real-Time markets. For example, if the TTC in an hour is 950 MW and the corresponding ETC volume is 375 MW, the residual ATC capacity made available in the Day-Ahead, Hour-Ahead and Real-Time markets will be:

950 MW – (375 MW + 375 MW + 175 MW) = 25 MW.

5.3.2.5 Steps in the Allocation of FTRs

The ISO proposes to allocate rights to transmission capacity in the following sequence of steps: (1) ETCs that do not convert to FTRs; (2) ETCs that do convert to FTRs; (3) LSEs; and (4) an auction open to all market participants who wish to bid for FTRs. Each step requires the ISO to run a simultaneous feasibility assessment on the relevant set of desired rights, after fixing the allocation of rights that resulted from the previous step. These steps are discussed in the next several sections.

5.3.2.6 Existing Transmission Contract Modeling and Conversion

The ISO's objective is to have a single congestion management system in which all users of the ISO control area participate according to the same rules and on the same scheduling time line. For this reason the ISO intends to design enough flexibility into the congestion management approach and the design of FTRs so that it will be feasible for holders of ETC rights to convert their rights to FTRs without adverse impacts in the form of unreasonable operating limitations or financial risks. As this proposal is being prepared, however, the ISO can not assess what share of ETC rights will be converted to FTRs by the time the Comprehensive Design is implemented. Therefore this discussion assumes that both converted and non-converted ETCs will exist and must be accommodated when the ISO initially implements the LMP design.[41]

5.3.2.6.1 Non-converted ETCs

As the first step of FTR allocation, prior to giving FTRs to converted ETCs and LSEs and prior to the FTR auction, some transmission capacity would need to be set aside to accommodate the non-converted ETCs. The ISO believes it is essential to use historic usage patterns to do this, because such a set-aside based on full nominal contract rights under a LMP approach would have too great an impact on the transmission capacity available to other users. ETC holders that do not convert will need to specify the sources and sinks (i.e., a balanced schedule) that best reflect their most likely use of their ETCs. The ISO would then perform a simultaneous feasibility of all the non-converted ETCs, treating them all as options rather than obligations, to determine the collective impact of all non-converted ETCs on the grid and remove this amount of transmission capacity from consideration in subsequent FTR allocation steps.

In the day ahead and hour ahead markets, ETC balanced schedules would be validated against the scheduling patterns that were specified by the respective ETC holders and would be given scheduling priority over all other schedules. Furthermore, where the ETC provisions provide for this, ETC capacity that is not scheduled day ahead will be reserved for possible use by the relevant ETC holders in the hour ahead market.

5.3.2.6.2 ETCs that convert to FTRs

Assuming that the ISO and some ETC rights holders are able to reach agreement on this issue, some of the current ETCs will be converted to FTRs. These FTRs should not be any different

[41] Because the continued existence of non-converted ETCs raises the concern of continuing phantom congestion, the ISO is considering implementing Recallable Transmission Service (RTS) as a device for allocating ETC capacity that is not scheduled on a day ahead basis to potential users who would be willing to purchase this product with the understanding that the ETC holder could exercise its scheduling rights and recall the capacity at a later time. RTS is discussed in more detail in another section of this proposal.

from FTRs auctioned in the primary FTR auction, except that they would be pre-assigned to ETC parties prior to the auction.

The ISO is currently considering what types of FTRs (options or obligations, PTP or FGR) will be needed to facilitate ETC-to-FTR conversion and whether the optimal FTR system is feasible to implement. Ideally the ISO would like to provide enough flexibility in the design of FTRs so that ETC holders can convert to a set of FTR instruments that best fits their ETC rights. In the simplest case a single FGR or a node-to-node FTR should be sufficient. If there are multiple sources and sinks in the ETC, it may be converted to a collection of node-to-node FTRs (i.e., a balanced schedule) that best reflects the most likely use of the ETC. If converted ETC parties schedule differently from this pattern, however, their FTR hedge may not be full. Since the ISO does not expect to be able to implement a mixed obligations and options FTR design initially, converted ETCs will be given obligations-type FTRs initially. The ISO will make every effort to develop and implement a mixed FTR design as early as possible, to make it possible to convert all ETCs to FTRs and thus eliminate the two separate congestion management approaches the ISO has had to operate since start-up and the associated problem of phantom congestion.

5.3.2.7 Allocation of FTRs to Loads (LSEs)

To receive this allocation LSEs would have to provide the grid usage patterns they normally rely upon to serve their loads. The ISO would then run an obligations-type simultaneous feasibility including all LSE requests for FTRs. The ETC capacity allocated to non-converted ETCs would not be available in this run, but the FTR capacity awarded to converted ETCs ("E-FTRs") would be put into the mix in order to allow for the effect of counter-flows under the obligations model. In the event that not everything is simultaneously feasible the ISO would presumably curtail LSE-FTR requests first and preserve E-FTRs as far as possible, to provide E-FTRs a higher degree of certainty of receiving their desired FTRs as a benefit for converting their ETCs to FTRs. Alternatively, if E-FTRs and LSE-FTRs are given the same level of priority, these two allocation steps could be combined into a single step.

5.3.2.8 FTR Primary Auctions

The FTR primary auction would be an optimization problem of maximizing auction revenue subject to simultaneous feasibility of all awarded FTRs. This problem is in Linear Programming formulation. To include a feature where a FTR bidder could specify a minimum quantity at a certain price would require the use of binary variables, and the optimization problem would then be in Integer Programming formulation, which is more complex and less robust.

A full network model with all transmission facilities in service will be used for the long-term and mid-term FTR primary auctions. The same full network model with external equivalents will be used in the FTR primary auctions, the Day-Ahead and Hour-Ahead Energy markets, and in Real-Time Economic Dispatch. All transmission facilities will be in service for the long-term and mid-term FTR primary auctions. As described above, the transmission capacity available in this auction would be reduced to reflect the historic grid use patterns on non-converted ETCs. The other two allocations – E-FTRs and LSE-FTRs – would be incorporated in the auction in such a way that they would not be reduced unless the owners wish to sell some of them. However, it is appropriate to include them in the simultaneous feasibility assessment of the auction because they are obligations-type FTRs. Auction participants would bid for FTRs by submitting balanced source-to-sink schedules at a price. The sources and sinks may be network nodes or hubs. Hub sinks would be distributed to their underlying load nodes using specified BLDFs. The short-term primary auction would be similar except that the network model would reflect short-term network conditions. Furthermore, the transmission capacity on each network branch and transmission interface would be set at the respective short-term FTR release. The network model used in the

Day-Ahead and Hour-Ahead Energy markets and in Real-Time Economic Dispatch would reflect actual hourly network conditions.

The revenues generated in these auctions would go to those E-FTR and LSE-FTR holders who sell some of their FTRs in the auction, and to PTOs for any FTRs sold that did not come out of the previously allocated E-FTRs and LSE-FTRs.

5.3.2.9 FTR Activity Rules and Monitoring

With the current proposal to release 75 percent of the lowest ATC for the previous 12 months as long-term and mid-term FTRs, there would not appear to be a need to impose position limits on FTRs. However, to satisfy the ISO's continuing monitoring obligation, we propose to retain the existing registration and reporting requirements. For PTP-FTRs, the FTR ownership on any given branch would be calculated using the PTDFs of the network model used in the primary FTR auction.

5.3.2.10 FTR Secondary Market

No changes are proposed, other than support for the secondary trade of FTRs auctioned in the primary auctions.

5.3.2.11 Modifications to FTR Release

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 ATC to be released in subsequent FTR primary auctions. When a new transmission line becomes operational, some ATC created by that line may need to be reserved for non-converted ETCs by virtue of their grid use patterns, while some shares of the increased capacity may go to E-FTRs and LSE-FTRs. The remaining ATC can be released.

In the case of a market-based transmission upgrade, the parties responsible for creating the new transmission capacity would also be entitled to FTRs. Possible ways to do this would be to provide FGR options in both directions over the new line, or to provide a set of point to point rights reflecting network flows over the new line.

5.3.2.12 Alternatives Considered

The major issue that was unresolved in the previous version of this Proposal and is resolved in the present version was the question of allocation of FTRs and/or FTR auction revenues to loads or LSEs. In the ISO's present FTR design there is no pre-auction allocation of FTRs to any party (except in the one instance to date where ETC rights have been converted), and all FTR auction revenues are given to PTOs to offset the Transmission Revenue Requirement (TRR) that is recovered through a per-MWh Transmission Access Charge (TAC). The question identified in the previous proposal was whether to provide either an initial allocation of FTRs or a share of FTR auction revenues to loads as a hedge against congestion charges. The alternative the ISO considered was to continue the current practice of paying all FTR revenues to PTOs to offset the TAC. As discussed above the ISO is proposing to allocate FTRs to LSEs in proportion to their loads, and then give the auction revenues from any remaining FTR capacity to PTO.

The following example illustrates the different impacts of these two options. The example makes the following assumptions, which refer to a typical or average operating hour of the year:

- The constrained area (Area A) has 1000 MW load and can only import 500 MW, while the neighboring unconstrained area (Area B) has 9000 MW load.

- Generation within Area A costs $100/MWh, while generation in Area B costs $30/MWh.
- Based on the above the total revenue required to compensate generators = $335,000.
- The TAC required to recover the TRR is $X per MWh, before accounting for any FTR or congestion revenues, and is charged to all load in both Area A and Area B.
- The auction price of FTRs will equal the expected cost of congestion (a standard economic assumption), and will also equal actual cost of congestion (the latter may not be true in every hour, but for an average hour should be approximately correct.).
- A TAC increase of $Y per MWh would result from building a transmission upgrade that completely eliminates the congestion.

The table below compares the outcomes of congestion management under four cases:

- The Base Case – Intra-zonal congestion management as is done today, which would apply in this situation assuming Areas A and B are contained within the same zone.
- Option 1 – LMP with the PTO getting all the congestion revenue and/or FTR auction revenue, and applying it to a reduction in the TAC, as is done today for inter-zonal interfaces.
- Option 2 – LMP, with Load holding the FTR and receiving the congestion revenue.
- After a transmission upgrade that eliminates the congestion.

Two important points are revealed by this example:

1. Giving FTRs to loads does not completely eliminate locational price signals, it only mitigates the congestion cost impact, but not the cost of the more expensive generation in the area.
2. Under Option 1 the cost impact on the TAC of the transmission upgrade is much greater (Y + $3.50) than under Option 2 (Y only), which makes it more difficult to build transmission upgrades.

	Base Case – Today's Intra-zonal	Option 1	Option 2	Transmission Upgrade – Option 1 or 2
MCP in Area A	$30	$100	$100	$30
MCP in Area B	$30	$30	$30	$30
Uplift needed	$35,000	NA	NA	NA
Total Revenue	$335,000	$370,000	$370,000	$300,000
Payments to Generators	$335,000	$335,000	$335,000	$300,000
Congestion Charge	NA	$35,000	$35,000	NA
Area A load gets	NA	NA	$35,000	NA
PTO gets	NA	$35,000	NA	NA
Offset to TAC	NA	$3.50	NA	NA
Area A load pays	$33.50 + X	$100 + (X - $3.50)	$65 + X	$30 + X + Y
Area B load pays	$33.50 + X	$30 + (X - $3.50)	$30 + X	$30 + X + Y

5.3.3 Conformance with FERC Standard Market Design

FERC Standard Market Design	*ISO Proposed Market Design*
"Source-to- Sink"	Yes
Obligations	Yes
Flowgate/Options when feasible	Yes
Expire in DA	Yes
Financial/Revenue Stream	Yes
Simultaneous Feasibility	Yes
Capacity Benefit Margin	Yes

5.3.4 Comparision of FTR designs of other ISOs

Attributes	NYISO	PJM	ISO-NE
Product Name	Transmission Congestion Contract (TCC)	Fixed Transmission Right (FTR)	Financial Congestion Rights (FCR)
Purpose	A financial instrument and serves as a hedge against congestion.	A financial instrument and serves as a hedge against congestion.	A financial instrument and serves as a hedge against congestion.
Energy Delivery	Not required.	Not required.	Not required.
Obligation / Option	Obligation.	Obligation.	Obligation.
Levels of Aggregation	Point to Point. Point to Zone.	"Are available between any single bus or combination of buses for which an LMP is calculated and posted (subject to simultaneous feasibility). The list of buses includes hubs, zones and single buses."	"Are available between any specified Locations for which an LMP is calculated and posted (subject to feasibility). The list of Locations includes Hub, Load Zone, Node and External Node."
Market Type	**Day-Ahead.**	**Day-Ahead.**	**Day-Ahead.**
Direction	Unidirectional (i.e., becomes obligation when congestion is reversed and no energy delivered by the Holder in the direction of congestion.)	Unidirectional (i.e., becomes obligation when congestion is reversed and no energy delivered by the Holder in the direction of congestion.)	Unidirectional (i.e., becomes obligation when congestion is reversed and no energy delivered by the Holder in the direction of congestion.)
Method of Distribution / Acquisition	Direct Sales, Centralized TCC Auction, Secondary Market	Network Integration Service (licensed by state regulators to serve end-use customers*)*, Firm Point to Point Service, FTR Auction, Secondary Market	FTR Auction, Secondary Market
ETC's	Also know as "Grandfathered Rights". During the transition period, these are being honored at the point to point level. However, they are being transitioned to TCC's. Grandfathered rights will be completely converted to TCC's by the Spring 2002. Basically, a capacity reservation is made for GF rights in the auction process.	No Grandfathered Rights	

Duration	The duration is dependent on when the FTR was/will be auctioned. Phase 1, "The Initial Auction for Long Term TCC's" had FTR durations of 6 months and 2 years. Phase 2, the "End-State Auction for Long-Term TCC's" is to take place in the Spring of 2002 and has a mechanism that "permits the bids submitted by the auction participants to determine durations of TCC's purchased" and, furthermore, that the "ISO will determine the minimum and maximum durations for TCC's sold". Lastly, there are "Reconfiguration Auctions" where "Monthly TCC's may be offered and purchased."	For Point to Point Service, the duration of the FTR is the same as the associated service request (one year, one month, one week or one day.) For residual FTR capability that remains after network and long-term Point to Point Transmission Service FTR's have been awarded, the term is one month.	Duration is established by the auction: six months/one year or one month.
Auction Frequency	The "End State Auction" is to be conducted annually and may be conducted semi-annually. The "Reconfiguration Auction" is held monthly and started after the Phase 1 auction.	The FTR residual auction is monthly. Consists of an on-peak and an off-peak auction.	"Two initial two "long term" auctions are conducted semi-annually. The first offers 10% and the second 25% of the transfer capability of the NEPOOL Transmission System. Thereafter, annual auctions offer 50% of the capability of the NEPOOL Transmission System, in one year increments, for the five calendar years beginning the following month. After each longer-term auction has been conducted, the remaining feasible FTR's are made available in monthly auctions. Each auction consists of an on-peak and off-peak auction."
Initial Allocation of FTRs	TCCs initially allocated to native load, and released grsadualy in TCC auctions (still in progress).	FTRs initially allocated to load serving entities as Network Integration Service (from specific resources to the network service customer's aggregated lopad). A network service customer's total FTR designation to a zone can not exceed the network customer's total load in that zone. The remaining FTRs to be released for auction (as price taker).	

Information source	This info comes from a slide presentation and was somewhat difficult to interpret.	This information comes from the online manual.	This information comes from the online manual.

5.4 Ancillary Services Markets

5.4.1 Introduction

The most significant design decision with regard to Ancillary Services (AS) is whether to retain the current sequential approach and procure AS using Rational Buyer after running the day ahead congestion management and energy market. The alternative approach is to utilize the simultaneous optimization approach and do energy, congestion management, AS procurement and unit commitment in an integrated run of the day ahead markets. The ISO proposes to use the simultaneous, integrated approach.

5.4.2 ISO Proposal

The ISO proposes that AS be procured simultaneously with the energy market. AS resources would be selected using an opportunity cost approach based on the resource's energy bid. The opportunity cost of a resource is determined as the difference between the clearing price for energy at a particular location and the energy bid of the particular resource at the loading point of its energy schedule, so long as the energy bid associated with the capacity in reserve is less than or equal to the clearing price. For example, if resource X were selected to provide 300 MW of energy it would have earned a market clearing energy price of $40/MWh based on a bid of $30 at the 300 MW level. Suppose instead it is selected to provide 100 MW of AS and only 200 MW of energy, and its energy bid at the 200 MW level is $25. If the energy market clearing price turns out to be $42, then its opportunity cost would be the area between the bid curve and the $42 horizontal line, between the 200 MW and 300 MW output levels, divided by 100 MW, which would be roughly $14 or15 per MW per hour.[42]

The ISO proposes to allow suppliers to submit capacity bids for AS in addition to their energy bid curves. Under this approach the resource's capacity bid would be paid as an adder to the opportunity cost determined from the submitted energy bids. The MCP for each service would then be the highest total price (energy opportunity plus capacity) paid for each service in each hour. One advantage of allowing a capacity bid is that it enables the supplier to incorporate the equipment costs and fixed costs associated with AS provision into its bid; this point may be particularly important for providers of regulation service. When capacity bids are allowed, one issue to resolve is how to apply mitigation to these bids.

The AS requirement could be determined on a system or local basis. If AS requirements are local there may be local AS clearing price differences for A/S capacity.

Just as today, high-quality services can substitute for lower quality services. For example spinning reserve service can substitute for non-spinning reserve.

AS should be procured subject to physical feasibility based on ramp rate and regulation limits.

AS may be provided via imports, however, some consideration must be given to transmission allocation. Whereas today transmission is allocated to AS capacity as it is available after congestion management; in a simultaneous solution allocation of transmission cannot be done sequentially. As a result both A/S capacity and energy could be competing for transmission across inter-control-area interfaces.

[42] The opportunity cost would be at least $12 ($42-$30) and at most $17 ($42-$25) per MW per hour.

5.4.3 Comparision with Other ISOs

Currently the New York ISO uses the capacity bid as an adder to the opportunity cost that is determined from the energy clearing price and the resource specific energy bid when selecting resources to provide AS simultaneously with the energy market. The AS clearing price is then set based only on the highest reserve capacity bid awarded, rather than on the full shadow price representing the combination of opportunity cost and capacity price adder.

5.4.4 Conformance with FERC Standard Market Design

FERC Standard Market Design	*ISO Proposed Market Design*
Bid-based, security constrained	Yes
Accommodates Bilaterals and Self-Schedules.	Yes
Multi-part Bidding	Yes
Bidding Limitations	Yes
Day-Ahead	Yes
Real-time	Under consideration
Clearing Price Auction	Yes
Accommodates Demand Bidding	Yes
Least Cost	Yes
Rational Procurement	Yes

5.5 Residual Day-ahead Unit Commitment

5.5.1 Introduction

The ISO will perform day ahead residual unit commitment (RUC) process after the day ahead energy/congestion management/ancillary services market has been run and has established final day ahead schedules. The RUC will allow the ISO to commit additional resources beyond those scheduled in day ahead if needed to meet the ISO's system load forecast[43] in compliance with NERC and WSCC reliability criteria.

The RUC process is both an October 1st Element and an element of the Comprehensive Long Term Design, the principal difference being the eligibility of resources to participate in RUC. The October 1st design has been described in a prior document. The fundamental differences are that (1) intertie supplies will be allowed to bid into the RUC in the short term but will no longer be permitted once the ISO starts running a day ahead energy market (unless they are identified as ACAP by a LSE), and (2) the ISO's proposed capacity payment for capacity committed in RUC will be eliminated once ACAP is effective. Once the day ahead energy market is operating, the

[43] Actually, the load forecast plus reserve requirements, to the extent adequate reserves are not self provided or offered in the day ahead market and not anticipated to show up in the hour ahead market.

RUC will only consider supply resources that either have been designated ACAP resources by a LSE in fulfillment of its ACAP obligation, or are otherwise subject to a must offer obligation. Resources so committed by the ISO would be guaranteed recovery of start-up and minimum load costs, net of market profits earned during the commitment cycle, and subject to restrictions on self scheduling and uninstructed deviations. In the long-term design intertie suppliers can be designated ACAP resources by a LSE, in which case they could be considered by the ISO in the RUC process; otherwise intertie suppliers who wish to offer energy on a day ahead basis should bid this energy into the day ahead energy market to be cleared against load bids.

5.5.2 ISO Proposal

This proposal has the following design features and characteristics.

1. The ISO will perform the RUC process immediately after the day ahead energy market has been run and has established the final day ahead schedules.
2. The capacity procurement target for the 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. Also, to the extent that municipal utilities under-schedule in the day ahead market but have 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 (see below for more details).
3. 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 will be limited to a maximum of 95 percent of the next day's hourly load forecast. The remaining 5 percent will be covered by the unloaded capacity of resources that are scheduled for energy in the day ahead (excluding any capacity scheduled to provide A/S) plus the unloaded capacity of any additional units committed by the RUC process. This 5 percent margin is intended to allow for load forecast error and 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.
4. ACAP resources will be the only resources considered in the RUC process, including resources that have not been scheduled for energy or AS in the day ahead energy market, including both quick-start and long-start-time units, as well as resources that have been scheduled in day ahead but have additional capacity available. Three-part bids will be required in the day-ahead energy market and used in this RUC process, including cost-based start-up and minimum load energy (based on the technical lower operating limit of the resource) and market-based incremental energy curves. Technical constraints like minimum load energy and minimum run time must be real physical constraints of the resource, not market-based bid constraints.
5. Resources not scheduled in the day ahead markets but committed in RUC will be guaranteed recovery of start-up and minimum load costs, net of market profits during the commitment cycle (i.e., the next 24-hour operating day) and subject to restrictions on self scheduling and uninstructed deviations. The unloaded capacity committed in the RUC may be dispatched in real-time based on the energy bids submitted to the RUC process.

6. The incremental energy bids associated with capacity selected in RUC can not be increased in price once they are selected, but may be decreased prior to real time if the resource bidder wishes to increase its probability of real time dispatch.
7. RUC will optimize its selection of resources by minimizing the total “bid” cost (where some bid components may be cost-based) of procuring resources and dispatching them for real time energy to meet 100 percent of the procurement target as defined in item 2 above. In performing the optimization RUC will consider start-up costs, minimum load costs and energy bids. In the case of resources scheduled in the day ahead that have additional uncommitted capacity the RUC will not consider start-up and minimum load costs.
8. For units whose start-up and minimum load costs are guaranteed by the ISO through the RUC process, any excess of these costs above the market revenues earned by the unit from real-time dispatch will be recovered through an uplift charge to load deviations from day ahead schedules. The ISO’s guarantee of these costs is contingent, however, on the resource being fully available for and responding to ISO dispatch instructions (accounting for any coordinated resource capacity limitations). Resources that submit a schedule in the day ahead market or are awarded A/S reserve will be assumed to have self-committed for the resource’s minimum run time and will not be compensated by the ISO for start-up or minimum load costs. If the ISO-committed resource chooses to schedule energy in the hour ahead, it will forfeit the start-up and minimum load costs for the entire commitment period. If the resource is awarded A/S in the hour ahead market the resource will forfeit its start-up and minimum load costs for the hour of award.
9. Units committed in RUC will be selected based on system reliability on a zonal basis when necessary. On October 1st, 2002, local reliability needs that are met today using Reliability Must Run (RMR) resources will continue to be met by RMR. When ACAP is fully implemented, locational market power mitigation is fully effective and a full network model is utilized for managing congestion, the reliance on RMR may end. At that point the RUC process could be used to address local reliability needs as well as system needs.
10. Cost causation principles will apply in allocating RUC costs. Costs associated with the RUC process will be borne by buyers whose load is not scheduled in the day-ahead market (excluding municipal load that is covered by its own resources, as described below).
11. The ISO is considering allowing Municipal utilities (“Munis”) 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.
12. The ISO proposes to allocate day ahead RUC charges to the negative deviations between day ahead schedule and actual load.[44]
13. Once the ACAP Obligation is fully effective, only ACAP resources will be eligible to participate in the RUC. Therefore, at that time energy-limited resources and demand side resources will be considered in the RUC process if these resources are designated ACAP resources.

[44] The costs to SCs for uninstructed negative deviations in real time include the real-time price, uninstructed deviation penalties if deviations exceed the specified tolerance band, and any costs for replacement energy that may need to be procured by the ISO through out-of-market transactions.

5.5.3 Example of Residual Unit Commitment

The following example illustrates how the RUC process will work. Assume for this example that Municipal Utility load is excluded from the analysis, consistent with the provisions described above.

(1) After the day ahead markets run, the ISO looks at the difference between its DA load forecast (plus reserve requirement) and scheduled load plus purchased A/S in the day ahead market, for each hour of the next day.

For example, suppose the difference for a particular hour is 5000 MW.

(2) In order to meet NERC and WSCC reliability requirements, the ISO wants to identify enough resources (including ancillary services) to be available in real time to meet this unscheduled load. First, it considers the amount of schedule changes expected in the hour ahead and the additional supplemental bids expected to come in prior to real time.

In this example, suppose this amounts to 1000 MW, so the ISO shortfall becomes 4000 MW.

(3) The RUC process procures additional resources from among (1) the energy bids of unloaded capacity that is already committed in the day ahead, (2) the start-up, minimum load and energy bids of Must Offer or ACAP capacity that was not self-committed in the day ahead, including both long-start-time and quick-start units, and (3) the energy bids submitted by demand response designated ACAP.[45] The algorithm RUC uses to select resources will minimize total expected costs as if the ISO were to procure the entire net short (4000 MW in the example).

Continuing with the above example, the forecasted shortfall is 4000 MW out of a system load forecast of 40,000 MW. The RUC should therefore procure 4000 MW of additional capacity to meet the load forecast, but should not exceed 2000 MW of energy procurement (from minimum load energy and any intertie supplies that may be designated ACAP) so as to stay within the 95 percent limit.

5.5.4 Relationship to Current Implementation of FERC's Must Offer Requirement

In response to the FERC's December 19, 2001 market mitigation orders, the ISO is currently developing unit commitment software to support the "must offer waiver" process that was implemented in response to FERC's initial establishment of the must offer obligation. The process for granting or denying waiver requests and for recalling units that were previously granted waivers is basically a residual unit commitment or RUC process. The unit commitment process that is being developed has as its objective the minimization of commitment costs of serving residual load, i.e., the difference between the ISO forecasted load and the day ahead scheduled load (assuming the forecast is greater than the schedule). Adjustments would be made to the residual load to be served by the unit commitment process to account for expected hour-ahead load schedule changes and expected real-time supplemental energy bids. The commitment process considers the start-up,[46] and minimum load costs.[47] The software being

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[45] Imports are also allowed in the interim (September 30, 02 implementation).

[46] Start-up costs are the fuel costs associated with starting up a resource. Start-up fuel costs are based on start-up fuel cost data provided to the ISO by the generator owners.

[47] Minimum load fuel costs are fuel costs associated with operating a unit at minimum load. Minimum load fuel costs are based on average heat rates at minimum load. For resources that can

used makes use of the Transmission Constrained Unit Commitment (TCUC) software similar to the software used by the NYISO. However, the California TCUC utilizes the current zonal network model rather than a full network model.

To replace the existing must-offer and must-offer waiver process, the ISO is proposing to extend and modify the use of the TCUC program for the new RUC procedure. TCUC software currently is capable of running a RUC process on a separate system from the day ahead scheduling system.

5.6 Structure and Timing of the Hour Ahead and Real Time Markets

5.6.1 Introduction

Since the beginning of ISO Operations on April 1st, 1998, the ISO has had a three-settlement system, with financial settlements based on final day ahead schedules, final hour ahead schedules, and real time deviations from final hour ahead schedules. Within this scheme the hour ahead market has provided the opportunity for Scheduling Coordinators (SCs) to submit changes to their final day ahead schedules. Schedule changes could be made in response to revised load forecasts, changes in unit availability, transmission outages, trades executed after the close of the day ahead market, or simply to exercise arbitrage between forward markets. The hour ahead market has thus provided the capability to make desired schedule changes close to real time and thereby limit exposure to the volatile real time market.

The ISO is now proposing to revise the hour ahead time line. The current time line requires schedules and bids to be submitted by two hours prior to the beginning of the operating hour (referred to as T-120 minutes). The hour ahead final schedules and prices are published by one hour prior to the beginning of the operating hour. This timeline allows for schedule changes reasonably close to real time and provides adequate time (one hour) for system operators to prepare for the upcoming scheduled ramp and Imbalance Energy requirements. However, the current time line has been raised as a significant issue by market participants who would like the hour ahead market to be moved as close to real time as possible.

The original timeline for the hour ahead market was designed to be as close as possible to real time while allowing adequate time for both SCs and operators to examine and react to the final schedules. Special consideration was given to the PX since the hour ahead final schedules needed to be relayed to PX participants, particularly the Investor Owned Utilities (IOUs), who then needed to submit Supplemental Energy bids for the Real-Time imbalance market, also passing through the PX including some validation steps. With the demise of the PX this special consideration is no longer necessary.

Currently, the submittal deadline for supplemental energy real time bids is T-45 minutes. Since the beginning of the ISO, real-time market operators have struggled with the dispatchability of supplemental energy that is not capable of mid-hour adjustments. Typically, intertie energy and some internally supplied energy is either unable or unwilling to make intra-hour adjustments.

continuously operate at a load of zero, the minimum load fuel costs are the same as no-load fuel costs.

This has resulted in a variety of pricing complications due to the different characteristics of these resources and resources capable of intra-hour changes.

The ISO is now proposing to close to the hour ahead market to market participant submissions perhaps as late as 60 minutes before the start of the operating hour. For this to be workable for the ISO, however, it may be necessary to stop accepting Supplemental Energy bids at the same time. This would allow ISO operators to run hour-ahead Congestion Management (CM) and energy, and then to issue pre-dispatch instructions as needed from among the energy bids that were not accepted in the integrated CM and energy procedure.

Allowing a window for energy trading as late as 60 minutes before the start of the operating hour will provide an opportunity for resources to be dispatched for hourly periods, with an hourly price commitment and timing that is near real time. (Resources with longer start-up times will have had previously the opportunity to be matched with loads in the day-ahead market.) The ISO believes that the trading opportunity created by the revised HA time line should satisfy the need that has been expressed by inflexible resources (i.e., those with operating characteristics that are not well-suited to 10-minute real-time dispatch) for a 60-minute dispatch market.

5.6.2 ISO Proposal

5.6.2.1 Hour Ahead Market Functions and Time Frame

Hour ahead energy and Ancillary Services (AS) will be procured simultaneously via a Transmission Constrained Unit Commitment (TCUC) process. This will eliminate the balanced schedule requirement and reduce the current processing time of the market. Based on these changes the closing of the hour ahead market can be moved closer to real-time, at least up to T-70 minutes. Depending on the actual processing time for the market the closing of the market may even be moved up to T-60 minutes. Final schedules will be published by T-45 minutes.

Congestion Management will be resolved simultaneously along with procurement of Energy and AS using TCUC. In running the day ahead market, scheduling priority will be given to final day ahead schedules over new hour ahead schedule changes that have not voluntarily submitted adjustment bids. Unloaded ACAP capacity is required to bid into both the hour ahead and real time markets. TCUC will produce nodal, hub, and shadow transmission prices. Nodal prices will be used for energy settlement for generators and will be aggregated for settling most load. These prices (nodal, hub, shadow transmission, and load aggregation areas) will be posted on an hourly basis prior to the beginning of the operating hour (T-45).

Utilizing bids left over from the hour ahead market designated as “hourly only” (i.e. not able to make intra-hour changes) and hourly supplemental bids (i.e. imports), the ISO will issue pre-dispatch instructions for imbalance energy based on the ISO load forecast. Pre-dispatch quantities will be calculated taking into account the expected RT imbalance. Imports that are pre-dispatched for the entire hour will be guaranteed their bid price. To the extent the simple average of the 10-minute prices for the hour falls below their bid price the difference will be paid as uplift. In-state 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 in-state generation is no longer needed, payment will be limited to the real time MCP as set by 10-minute dispatchable resource bids.

5.6.2.2 Participation in Hour-ahead and Real-time Markets

Submission of HA and RT Incremental (INC) Energy Bids will be in accordance with the following principles:

- All resources committed in RUC must either maintain their DA energy bids or reduce them, if desired to increase likelihood of real time dispatch. Energy bids from resources committed in RUC cannot be increased.
- All ACAP resources must submit energy bid curves for the full amount of their designated ACAP capacity.
- Demand Resources may submit bids to reduce energy consumption in RT, provided their real-time reduction is visible to the ISO.
- Non-ACAP resources, which will be precluded from participating in the DA RUC process once the ACAP Obligation takes effect, may participate in the HA and RT Markets.

Submission of HA and RT Decremental (DEC) Energy Bids will be in accordance with the following principles:

- Non-ACAP generating resources that are scheduled to supply energy may submit bids to reduce energy output.
- ACAP resources that are scheduled to supply energy must submit bids to reduce energy output.
- Demand Resources may submit bids to increase energy consumption in the HA market, but not in the RT market.

5.6.2.3 Automated Mitigation (AMP) on Hour-ahead and Real-time Bids

AMP will be applied to bids in both the HA and RT markets. Greater detail on the AMP process and triggers can be found in a later section of this proposal.

5.6.2.4 Real Time Economic Dispatch

Real-time dispatch will consider supplemental energy bids only for resources capable of intra-hour adjustments. Real-time Imbalance Energy dispatch will be accomplished using a Security Constrained Economic Dispatch (SCED). The SCED will produce nodal and hub energy prices. Absent real-time transmission constraints imbalance energy will be economically dispatched based on submitted energy curve.

5.6.2.5 Real Time AS Procurement

The ISO may in some instances procure residual amounts of AS in real time if needed to maintain reserve requirements during the hour.

It would be feasible to designate AS capacity in RT from unloaded capacity that bids into the RT market. The capacity MCP for AS designated in RT would be determined from the opportunity cost of energy, and all resources designated AS in RT would receive this RT AS MCP. Real time buy-back of any AS procured by the ISO in a previous market would be required to pay the higher of the RT price or the price the resource was paid when it was procured.

5.6.3 Comparision with Other ISOs

The New York ISO has a day ahead and a real time settlement market, but no hour-ahead settlement market in between (although there is an advisory hour-ahead balancing market). The NY ISO's Day Ahead Market trades and schedules Capacity, Energy, and Ancillary Services for the following day. The Day Ahead Market closes at 5:00 AM for the following day.

The NYISO's Real Time Market trades Capacity, Energy, and Ancillary Services for one-hour periods. The Real Time Market closes 90 minutes before the hour being scheduled.

5.6.4 Conformance with FERC Standard Market Design

FERC Standard Market Design	*ISO Proposed Market Design*
Bid-based, security constrained	Yes
Single-part Bid (energy)	Yes
Bidding Limitations	Yes
LMP – Nodal	Yes
Clearing Price Auction	Yes
Imbalances Settled at Real-time Price	Yes
Undecided on Deviation Penalties	ISO proposes penalties
Accommodates Demand Bidding	Yes
Accommodates Energy-limited, Intermittent Resources	Yes

5.7 Real-time Economic Dispatch using Full Network Model

5.7.1 Introduction

The MD02 team proposes a security-constrained economic dispatch (SCED) for the real time market, to fully take into account all transmission constraints, local reliability needs, loop flows, generator operating constraints, and imbalance energy needs. This approach would produce nodal real-time energy prices, which would be paid to generating resources and Participating Loads but may be aggregated for settling load deviations. An adapted version of this design, using economic dispatch (ED) compatible with the three existing zones (NP15, SP15, and ZP26) rather than the full network model, will be implemented in Spring 2003. In addition, the ISO proposed in Amendment 42 to begin the transition to economic dispatch in real time by clearing overlapping imbalance energy bids. The ISO believes it is important to implement this initial step as soon as possible to eliminate the "Target Price" mechanism that has been subject to manipulation since the start of ISO operations. The ISO will therefore re-submit this element of Amendment 42 in the context of its May 1, 2002 Tariff filing.

The full design proposed here, based on the full network model, is compatible with FERC's Standard Market Design (SMD). This section describes the full design. The Amendment 42 proposal and the adapted version for implementation in Spring 2003 areintended as the first stages in a phased implementation, with the full network model implemented in Fall 2003 to allow adequate time for software and system implementation and testing. Section 5.2 discusses the ISO's proposed implementation phases in more detail.

5.7.2 ISO Proposal

5.7.2.1 Overview

The ISO proposes to develop and use a Real Time Security-Constrained Economic Dispatch (SCED) optimization program to simultaneously procure imbalance energy (IE) and manage congestion. This represents a fundamental change from the current design where IE is procured from a merit order stack (the BEEP stack). Currently the ISO performs real time inter-zonal Congestion Management by separating the stack by congestion region, thus establishing different real-time energy prices in the regions between which there is congestion, and performs intra-zonal Congestion Management by dispatching resources out-of-sequence when needed to relieve a local constraint.

The SCED will use a Full Network Model (FNM) and will eliminate the distinction between inter-zonal and intra-zonal congestion. The SCED will be based on an AC-Optimal Power Flow (AC-OPF) methodology that will minimize the real-time cost of imbalance energy, determined from energy bids submitted by participating resources, subject to transmission interface, nomogram, and resource capability constraints, and taking into account transmission losses. The SCED will accommodate contingency lists that may be explicitly specified. This capability would not be needed for operating nomograms and those transmission interfaces where the Operating Transmission Capacity (OTC) already includes the impact of contingencies implicitly. The energy bids of participating resources that can exercise local market power will be mitigated in accordance with the bid mitigation provisions described elsewhere in this proposal. The ISO expects to have a State Estimator (SE) implemented in time for the implementation of the full scale SCED. The SCED will then rely on the State Estimator results for the base data used by SCED (instead of unfiltered telemetered data) and for the transmission loss penalty factors.

The SCED will be run every 10 minutes during the hour to determine which resources to dispatch at what operating levels to meet real time needs, taking into account local reliability, transmission, and technical resource constraints, and will produce nodal real-time energy prices. This change would eliminate the current two-price system[48] (separate INC and DEC prices in each interval), and under the settlement mechanics generally adopted by the ISO (whereby there is practically no explicit or implicit charge for "replacement cost of energy" for not following dispatch instructions), would make it necessary to apply a system of penalties for resources that vary from ISO dispatch instructions beyond a reasonable tolerance band.

Real-time market settlements will be based on nodal prices for supply, and on more general "locational" prices for loads, including individual nodes or aggregations of nodes such as load groups and demand zones (generally referred to as "Load Aggregations"; see Section 5.8 for a full description of Load Aggregations). The aggregated prices would be derived as weighted averages of the nodal prices in each aggregation, with the weights equal to the corresponding dispatch volumes.

Due to implementation considerations as mentioned above, the proposed SCED using a FNM involves an intermediate implementation phase. In this phase, the ISO will have to use the current three-zone network model; no working State Estimator would be in place; and there will be no requirement to accommodate specific contingency lists.

[48] In fact, the ISO proposes to eliminate the system of separate INC and DEC prices as soon as it receives FERC approval to clear overlapping imbalance energy bids and eliminate the target price mechanism, as mentioned above.

Table 1 below compares the salient features of the ISO's real-time market proposal with the current design.

Table 1. Comparison of Current and Proposed Real-time Market Designs

Feature	Current Design	Proposed Design
Methodology	Merit Order Stack	Optimization
Network Model	None. The merit order stack is separated across congested inter-zonal interfaces to simulate a zonal network model.	Full Network Model based on the existing detailed operational model.
Management of imbalance energy requirements and Inter and Intra-LPA congestion	Imbalance energy (IE) is procured in merit order. Inter-zonal congestion is resolved by procuring IE separately by congestion region after separating the stack. Operator resolves real-time Intra-zonal congestion with out-of-sequence dispatch.	Optimization simultaneously satisfies Imbalance energy requirements and manages transmission congestion (with no distinction between inter and intra-zonal congestion).
Real-Time Pricing	Ten-minute market design: positive (negative) instructed deviations are paid (charged) the incremental (decremental) zonal MCP; positive (negative) net uninstructed deviations by SC and by zone are paid (charged) the decremental (incremental) zonal MCP.	Locational pricing for instructed deviations (consistent with the ten-minute market design). Penalties for uninstructed deviations.

5.7.2.2 Network Model

The ISO proposes to utilize a Full Network Model (FNM) in RTD. The FNM will be a detailed network model of the CAISO controlled grid, expanded by an external equivalent to model the rest of the Western Systems Coordinating Council (WSCC) interconnected system. The external equivalent will preserve all scheduling points and inter-ties into the CAISO controlled grid, while the remaining external system will be reduced through network reduction techniques to external loops.

The FNM will accurately represent the effectiveness of all resources with respect to mitigating congestion at any point in the CAISO controlled grid and the inter-ties. In that respect, the FNM will result in accurate dispatch of all resources to both procure imbalance energy and mitigate congestion in real time.

The FNM will be an AC network model. Therefore, the power injections and ejections in the FNM will represent gross power supply and net power consumption, since transmission losses are accounted for explicitly.

5.7.2.3 Dispatch Method

Real-time dispatch would be based on the results of an AC-OPF that will minimize the real-time cost of imbalance energy, determined from energy bids submitted by participating resources, subject to transmission interface, nomogram, and resource capability constraints, while accounting for transmission losses. Explicit contingency lists may generate additional constraints to be accommodated.

Real-time dispatch will be performed automatically at the beginning of each ten-minute dispatch interval, and if necessary, manually by the operator at any time within the hour. The imbalance energy requirement will be calculated from: (1) the current aggregate deviation of Automatic Generation Control (AGC) units from their respective Preferred Operating Points (POPs); (2) the system load forecast for the next ten-minute interval; and (3) the changes in generation and inter-tie schedules between the current and the next hour.

Power flow limits will be enforced on all interfaces and the individual branches that comprise them. Furthermore, nomogram constraints will also be enforced. Nomogram constraints will be approximated by piece-wise linear inequalities relating area generation, area load, and transmission interface power flows.

Real-time data that is required for SCED, (e.g., generator output, area load, and transmission branch power flows) will be provided by a State Estimator (SE) function included in the Energy Management System (EMS). The dispatch instructions will be communicated to participating resources automatically through the Automated Dispatch System (ADS).

5.7.2.4 Pre-Dispatch

In order to prepare short-start resources for real-time dispatch and coordinate interchange scheduling, the ISO will perform a pre-dispatch process 30 to 45 minutes prior to the operating hour. Pre-dispatched interchanges that are constrained from adjusting their schedules during the hour will be dispatched for the hour and will be paid the higher of their bid price and the simple average of the six interval prices established by 10-minute dispatchable resources. The pre-dispatched hourly interchange bids will not be allowed to set the 10 minute Market Clearing Price.

5.7.3 Local Market Power Mitigation

The resources required to mitigate real-time congestion due to system contingencies (transmission line or generator outages) have the potential to exercise local market power due to the absence of competition to provide the needed services.

To effectively mitigate local market power in real-time, the ISO proposes to mitigate bids in real-time to the unit's cost-based proxy price if the ISO is required to use those bids to mitigate local (i.e., intra-zonal in today's zonal model) congestion. This is consistent with the authority already granted by FERC to other ISOs. The authority to cap bids when local congestion occurs clearly reflects the reality that local reliability problems give rise to market power for which there is no competitive solution – not in California, or in any other state.

For resources with no fuel cost, e.g., hydro units, the mitigated bid will be determined based on recent historical real-time locational prices at the corresponding resource's location for the corresponding hour (peak or off-peak) for a number of similar days where the resource was dispatched in economic merit order. Standing bids at the mitigated levels would be used for reliability resources not under maintenance or forced outage if they do not participate in the imbalance energy market, but they are needed for local reliability.

The ISO will identify the resources that have locational market power in mitigating specific constraints that will be enforced in SCED. When these constraints become binding in real-time the solution will be re-calculated using the mitigated energy bids for the relevant resources.

5.7.4 Penalties for Uninstructed Deviations

Under a single real-time pricing scheme, there is no effective replacement charge for not delivering acknowledged dispatch instructions. Accordingly the ISO proposes to incorporate penalties for uninstructed deviations from the dispatch instructions. Moreover, declining real-time dispatch instructions is a serious form of physical withholding. There is currently no mitigation against this behavior, although the ISO tariff (section 2.5.22.4.1) states that all real-time bids not withdrawn 45 minutes before the operating hour are binding. The ISO proposes to treat declined instructions as acknowledged instructions that are not delivered unless the resource in question undergoes a forced outage and the SC notifies the ISO in time (within 30 minutes from the occurrence of the forced outage).

The proposed penalties for positive uninstructed deviations will be the quantity of Uninstructed Imbalance Energy in excess of the tolerance band multiplied by a price that initially will be equal to 100% of the corresponding BEEP Interval Ex Post price. Thus the net effect of the uninstructed deviation penalty and the settlement for positive uninstructed deviations beyond the tolerance band will be that the supplier will not be paid for any such Energy. The uninstructed deviation penalty for negative uninstructed deviations will equal the amount of Uninstructed Imbalance Energy in excess of the tolerance band multiplied by a price that will be set initially equal to 50% of the corresponding BEEP Interval Ex Post price. Thus the net effect of the uninstructed deviation penalties and uninstructed Imbalance Energy settlement will be that this energy will be charged at 150% of the corresponding BEEP Interval Ex Post price.

The ISO proposes a tolerance band for uninstructed deviations before applying the penalty. The tolerance band is to be the greater of 5 MW or 3% of the maximum operating limit of the resource[49] (*i.e.,* Pmax).

5.7.5 Settlement

For each real-time dispatch optimal solution, a nodal price for IE supply or demand will be calculated at each node of the FNM. The nodal price is the incremental cost of supplying load or reducing generation at the corresponding node.[50]

Accurate imbalance energy (IE) pricing, consistent with the real-time dispatch, will require the use of nodal prices to settle instructed deviations. This approach will also result in a settlement that does not require uplifts that distort price signals and reduce transparency. Uninstructed deviations by non-dispatchable resources (including loads) will be settled at a weighted average price for the appropriate load aggregation, consistent with the 10-minute settlements. Uninstructed deviations by dispatchable resources will be settled at the nodal price in the corresponding location, including the penalties stated in the previous section if the deviation is outside a specified band.

The real-time dispatch solution and the associated nodal prices are valid only for one instance in time, although the imbalance energy is the integral of the resource supply or demand, above or below the final HA schedule, for a ten-minute interval. Therefore, for payment adequacy, instructed IE is proposed to be settled as follows:

[49] "Resource" in this instance may be defined as the aggregated units, net expected generation for MSS, delivered Regulation range or scheduled load for PLA.

[50] The ISO will probably need to incorporate nomogram constraints into its real-time dispatch models, As a result, when certain nomogram constraints are binding at the solution, the nodal price for generation may be different than the nodal price for load at the same node.

- Positive instructed IE will be paid the highest of all nodal prices calculated by the real-time dispatch at the respective node within the corresponding interval, and the nodal price calculated by the last real-time dispatch at the respective node in any previous interval of the current hour.
- Negative instructed IE will be charged the lowest of all nodal prices calculated by the real-time dispatch at the respective node within the corresponding interval, and the nodal price calculated by the last real-time dispatch at the respective node in any previous interval of the current hour.

Uninstructed deviations by non-dispatchable resources will be settled as follows: Positive or negative uninstructed IE by non-dispatchable resources will be paid or charged, respectively, at the appropriate aggregated price for the relevant interval. The aggregated price would be calculated as a weighted average of the nodal prices in the corresponding aggregation for that interval, but bounded within the lowest and highest nodal price within the aggregation for that interval. The weights in the weighted average will be the net uninstructed IE at the corresponding node for that interval. If there are multiple real-time dispatch solutions within an interval, the highest or lowest nodal price will be used in the aggregated price calculation depending on the whether the net uninstructed IE at the corresponding node is negative or positive, respectively.

Uninstructed deviations by dispatchable resources will be settled at the relevant nodal prices.

Since nodal and locational price differences across the system are the result of real-time congestion, any congestion revenue collected through the real-time settlement for IE will be distributed to all Scheduling Coordinators in proportion to their metered demand, as part of the neutrality charge. However, the ISO is currently evaluating the possibility of extracting the congestion revenue from the neutrality charge and allocating it differently. The remaining concepts of the ten-minute market design, e.g., IE accounting, ramping and residual energy, no pay, etc., will continue to apply under the proposed design.

5.8 Demand Scheduling, Bidding and Settlement

5.8.1 Introduction

A crucial feature in the locational marginal pricing (LMP) market design the ISO is proposing is the geographic granularity used for scheduling and financial settlement of loads. The major changes resulting from the ISO's proposed Comprehensive Design will occur when the ISO implements the full network model in the forward energy and congestion management markets, when nodal prices for energy will be produced in the forward (hourly) and real time (10-minute) energy markets.[51] If the differences in the costs of energy to serve consumers in different

[51] The market design features to be implemented on October 1, 2002 and in spring of 2003 will have little impact on the scheduling and settlement of load. The ISO does not expect to make changes to load scheduling protocols or settlements of load schedules or deviations until the full network model is implemented in fall of 2003. Similarly, no change should be needed to bidding protocols or settlement for ancillary services or supplemental energy provided by Participating Loads, except that multi-part, market-based bids may be submitted and that a single energy bid will be used for all energy services in real time. The opportunity for bidding into the RUC process, effective 10/1/02, is discussed in Section 5.8.2.2.

locations are significant, there could be significant cost impacts introduced by the adoption of LMP – depending on the geographic granularity of load scheduling and settlement and on the hedging tools or other mechanisms that loads may use to limit their exposure to congestion costs. Today, locational differences in energy costs are hidden because energy prices in the ISO's real time market are no more granular than the major congestion zones. Even when there is intra-zonal congestion, the costs are spread across the major congestion zones, and the costs of RMR for local reliability are spread to entire PTO service territories as well as other users of the transmission system.

The fundamental tradeoff to be considered is between (1) sending strong locational price signals to all market participants, to maximize the incentive effects of LMP for investment in transmission, location of new generation, forward contracting and demand responsiveness, and (2) the potential for severe cost impacts on consumers in congested areas due to constraints in a transmission system that was designed and built under an entirely different regulatory regime, one which did not anticipate competitive generation markets and locational pricing. The second point raises legitimate issues of fairness, which are addressed below. It also requires that we try to address in a realistic manner the question of how to upgrade transmission into congested areas to enable consumers in these areas to enjoy the benefits of competitive energy markets. To that end, as explained more fully in the Section 5.1 of this design document, the ISO is committed to a proactive transmission expansion process; a process that results in appropriate and timely expansion of the ISO Controlled Grid. Moreover, the ISO is committed to a proactive transmission planning and expansion process that is tightly integrated with both its ACAP and RMR policies. While a satisfactory answer to the transmission question is beyond the scope of ISO market redesign, the ISO will pursue efforts to further expand the system in parallel with the market redesign effort.

FERC has recognized this tradeoff in its recent working paper on the standard market design (SMD). While emphasizing the need for "price signals that reflect the time and locational value of electricity," FERC also notes that "while price signals should support efficient decisions about consumption and new investment, they are not full substitutes for a transmission planning and expansion process that identifies and causes the construction of needed transmission and generation facilities or demand response."[52]

The ISO has previously noted in its assessments of the root causes of California's 2000-2001 energy crisis that in certain high-consumption areas of the grid the transmission system is not adequate to support competitive supply of electricity, and that transmission upgrades are needed to enable consumers in these areas to benefit fully from competition in generation. As FERC notes, however, simply sending locational price signals to consumers in these areas is not likely to be sufficient to elicit the needed investment.

Moreover, in a presentation to the ISO Board of Governors on April 9, 2002, Dr. Frank Wolak, Chair of the ISO's Market Surveillance Committee argued that much greater incentives for developing demand responsiveness would result from time-varying (i.e., hourly) pricing of electricity than from location-varying pricing.

The foregoing observations suggest that two of the major root causes of California's electricity crisis – inadequate transmission capacity and limited demand responsiveness – would be better remedied by changes other than extremely granular locational pricing of energy to loads. These other changes, moreover, require additional actions by parties other the ISO. To be specific, the ISO has established a control area wide transmission planning process to identify needed

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52 Federal Energy Regulatory Commission Working Paper on Standardized Transmission Service and Wholesale Electric Market Design, March 15, 2002, p. 6.

transmission upgrades, and has engaged a consultant to develop a viable methodology for performing economic analysis of proposed transmission projects. The ISO can not, however, cause transmission facilities to be built; this is a matter for policy makers outside the ISO to resolve. Similarly, the ISO markets are based on hourly and 10-minute prices, providing all the time-varying price signals needed to induce consumers to respond. The Comprehensive Design Proposal would improve upon these signals by creating day ahead and hour ahead hourly energy prices with greater price transparency than exists today. The ISO can not require loads to be priced at these time-varying rates, however, except for loads that participate in the ISO's markets, and then only to the extent of their participation.

Besides the cost impacts of locationally granular pricing for loads, there are also technical difficulties involved in implementation. Currently loads schedule at the Demand Zone level (see the table of Load Aggregations later in this section), a level which is relatively coarse compared to the three thousand or so nodal prices that will be generated by LMP. Moreover, SCs currently provide settlement quality meter data (SQMD) to the ISO at the same level. Increasing the granularity of load scheduling and settlement will require modifications to both the scheduling and the meter data management processes of SCs as well as those of the ISO.

The foregoing discussion should not be taken to undermine the value of the LMP approach. The ISO believes that LMP offers an effective and proven approach to managing congestion in the ISO's forward markets, and that it does this through the locational energy prices it creates as the basis for settlement. Moreover, it solves many of the long-standing problems with the ISO's existing forward congestion management approach by creating forward schedules that are feasible with respect to transmission and generator operating constraints. (Particularly important in this regard is the settlement of generators at the nodal level.) The conclusion the ISO draws from the issues raised above is that an appropriate transition is needed to the full effectiveness of LMP. If we proceed to full implementation before some of the root causes of the California are addressed – by policy makers and state agencies in addition to ISO market design – there will be substantial impacts on loads without necessarily inducing the needed resolution of those root causes.

FERC has recognized these issues in its recent SMD papers and noted the need for a transition to the SMD: "To satisfy [the principle of the March 15 working paper that customers with existing contracts (real or implicit) should continue to receive the same level and quality of service under SMD], existing customers [e.g., LSEs] … should receive a conversion right for the initial Transmission Rights. … If the use of the system by existing customers is not recognized in the transition mechanism, either through an allocation of Transmission Rights or an allocation of the auction revenues for these rights, there may be significant cost shifts because of congestion costs. The objective of this option is to preserve the service quality for the load served by the existing customer." [April 10 Options Paper, p. 11]

As a result of these complex policy issues and technical considerations, the ISO proposes to utilize Load Aggregations as a permanent feature of the new design. When nodal pricing begins operation with the implementation of the full network model in fall of 2003, the ISO proposes to schedule and settle loads at the Demand Zone level, and to migrate when technically feasible to the Load Group level.[53] In addition, the ISO proposes to allow LSEs to create custom Load Aggregations for scheduling, and settlement when feasible, using the actual nodes at which they serve load, provided there is appropriate revenue quality metering to enable the ISO to verify the accuracy of the custom aggregation. Individually loads with adequate metering and metered subsystems may also elect locational pricing that coincides with their actual locations.

[53] There are roughly 20 Demand Zones within the ISO control area, and just over 40 Load Groups identified at this time; for a complete list see the table of Load Aggregations later in this section.

Finally, to mitigate the impact of congestion costs to loads under the proposed LMP design, the ISO proposes to provide an initial allocation of Firm Transmission Rights (FTRs) to loads based on their historic load levels and grid use patterns. These FTRs will effectively neutralize the impact of any congestion charges resulting from LMP in the day ahead market. FTRs are not likely, however, to fully eliminate the locational impact on loads when high-cost generation must be procured to serve their needs due to congestion constraints. Refer to Section 5.3 for a more detailed explanation of the allocation of FTRs to loads and an example to illustrate the effect of FTRs in mitigating congestion costs.

Resolution of some technical details regarding load scheduling and settlement at the level of the proposed Load Aggregations will continue during implementation of the comprehensive market design described herein, and will include continued interaction with stakeholders. In particular, the ISO has not yet established a specific timetable for moving from scheduling and settlement at a Load Aggregation level similar to current Demand Zones to one similar to Load Groups. Such a timetable will require further assessment of the time required for all parties to implement the changes to their systems, the cost of making these changes, and possibly other factors such as the completion of transmission upgrades into severely constrained areas that may affect the timeframe for this migration.

5.8.2 ISO Proposal

Generators will be scheduled at the nodal level and be settled for deviations at the nodal level, load will be represented in congestion management at a nodal level, and energy and congestion prices will be determined at the nodal level. However, load is served from many more buses than generation delivers into, which could increase the implementation difficulty for the ISO as well as market participants if load were required to schedule at the bus level. The business interface for market participants can be either at the nodal level or through aggregations of nodes. For example, PJM allows loads to be scheduled at multiple levels, including bus, demand zone, hub, and various aggregations of these levels. The California ISO currently has defined “Load Groups” that reflect the boundaries of small utilities (e.g., Anaheim, Santa Clara, Pasadena, etc.) and meaningful boundaries in the large utilities’ (PG&E's and SCE's) transmission systems, as well as “Demand Zones” that are aggregations of some Load Groups, and congestion zones that are aggregations of Demand Zones.

There are tradeoffs in selecting allowable levels for scheduling and settlement, including cost exposure, feasibility, and accuracy. For example, allowing the current aggregations to be used (with refinement as needed) can minimize changes to metering and master file definitions,[54] while using a finer granularity can help the network model solution by providing a more refined load distribution (although fine granularity could also make the model results sensitive to input data errors).

Four general factors are involved in this decision:

1. Establishing the highest allowable level for scheduling and settlement of load,

[54] SCs can currently schedule load at the demand zone, load group, or bus levels, at their choice, even though for operational purposes these are all combined into three congestion zones. The ISO anticipates continuing a comparable practice, in which SCs that submit schedules at a more granular level (e.g., node) than the default level for scheduling, but have not elected to be settled at the more granular level, will simply be added to the total for the default, aggregated level.

2. Determining whether and how the cost impact of locational pricing should be offset to make Load Serving Entities (LSEs) financially neutral between alternative levels of aggregation, for example by using an allocation of benefits from FTRs,
3. Allowing LSEs to schedule at alternative levels of aggregation, and establishing the process for this to occur, and
4. Establishing specific definitions of the load aggregations.

The ISO proposes the following features to resolve the four general issues identified above, for reasons to be discussed in subsequent sections:

- By default, schedule and settle load at aggregated levels identified in Section 5.8.2.1, which include a level similar to the existing Demand Zones (applicable when the Full Network Model is initially implemented), and a level similar to existing Load Groups. Scheduling and settlement of load will migrate from the broader aggregations to scheduling and settlement at the less aggregated level (similar to the current Load Group level).[55]
- Loads will be made financially neutral, for at least a portion of their load, to scheduling by existing congestion zones through allocation of FTRs, as described in Section 5.3.
- Loads can elect to schedule at the nodal level, or at aggregations of nodes including both (a) the standard aggregations identified in Section 5.8.2.1, and (b) aggregations that would be defined at the request of market participants to reflect the specific location of loads and/or distributed generation. Loads will initially be settled at the level of the standard load aggregations defined in this section, and mechanisms will be further explored to allow settlement at a more granular level.
- The standard load aggregations that are used to implement these features will be refined from current definitions of both Demand Zones and Load Groups.

The basis for this proposal is reviewed in Section 5.8.4. Issues related to its implementation are discussed in the remaining subsections of this Section 5.8.2 and in Section 5.8.3.

5.8.2.1 Definitions of the Load Aggregations

To facilitate further discussion of the ISO's proposal, three terms will be used to describe the various levels of aggregation:

1. Trading hub. This level corresponds to the current congestion zones: NP15, SP15, and ZP26. These definitions will be maintained as index values for reference in trading among market participants. Inter-SC trades will be supported at this level, but load may not be scheduled at this level. The weighted average prices at this level will reflect all load within the boundaries of the current congestion zones, regardless of which load aggregation is used to schedule and settle the load.
2. Load aggregation: This level is established to simplify the business interface that the ISO and market participants use to schedule and settle load, and its features are discussed throughout this Section 5.8. Standard aggregations will be established, but loads may elect to schedule at the nodal level or using a non-standard aggregation.
3. Node: This level is the take-out point that is represented in the Full Network Model, and may be voluntarily used for scheduling load instead of using a load aggregation.

[55] Specifically, the load aggregations identified in Section 5.8.2.1 as PGE3 and SCE1 will be discontinued when this migration is complete.

Standard load aggregations will be established, based on the currently defined Demand Zones and Load Groups, and on the Local Reliability Areas (LRAs) that are part of the proposed ACAP requirement as well as defining current Reliability Must Run (RMR) needs.[56] An initial definition of standard load aggregations is provided in the table below.

Changes from existing Demand Zones and Load Groups include the following. (As a reference the reader may wish to compare these with the Locational Pricing Areas (LPAs) that were identified in the ISO's January 2001 Congestion Management Reform (CMR) Proposal.) The existing North Coast load group was divided into the North Bay and Fulton Geysers areas (which exclude some nodes in the North Coast load group) in the CMR process; the single San Francisco area contains both the San Francisco and North Peninsula load groups; and the Fresno area includes part of the Yosemite load group in addition to the existing Fresno North load group. The Battle Creek LRA is part of the North Valley load group; the Sierra LRA includes part of the Sacramento and Sierra load groups; and the Stockton LRA includes parts of the Stockton and Stanislaus load groups. The proposed LRA-based standard load aggregations include only the portions of current RMR areas where the ISO has identified capacity needs for 2002 to 2004; the Chico RMR area is not a proposed load aggregation for this reason.

In addition to these areas, the ISO has further reviewed the modeling results from the CMR project to reassess the definition of LPAs adopted in that project, and to determine where any other price differences between load groups are significant. The Greater Bay Area LPA was found to include four areas with meaningful price differences. Additional areas with meaningful price differences can also be found, such as hydro-rich areas in the Sierras. In the SCE service area, little price difference was found except for the Los Angeles - Orange County LPA, so the other SCE load groups may be combined until experience with locational pricing reveals price dispersion patterns. As noted elsewhere in this proposal, the ISO intends to have the full network model operational for study purposes for several months prior to the implementation of LMP, so that the ISO and Market Participants may gain experience with nodal prices in the ISO control area. Based on the results observed in this study period it may be necessary to make some changes in the definitions If the standard load aggregations, so business systems will need to be designed for flexibility instead of incorporating a rigid definition of load aggregations.

As noted above, the ISO's proposal also allows LSEs to establish non-standard load aggregations to identify the specific locations of their customers while simplifying the business interface that they can use for scheduling and settlement. The process of establishing these load aggregations is discussed further in Section 5.8.4.3.

The ISO will publish prices for each of its markets for the Trading Hubs and Load Aggregations listed in the following table, will provide prices for each bus as downloadable files, and will publish additional data as needed.

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[56] Even if the ACAP Obligation is not adopted, the LRAs correspond to RMR areas that would continue to define RMR requirements. Accurate scheduling and pricing of load in these areas would continue to be important in this event.

Initial Definition of Standard Load Aggregations
(Work in Progress)

Trans-mission Area	Trading Hub	Load Aggregation		Name and Correspondence to Existing Load Groups[57]
PGAE	NP15	PGE3	*PGHB*	*Humboldt (PG&E Humboldt/ PGHB) (current PGE1 demand zone)*
			PGSF	*San Francisco (PG&E San Francisco/ PGSF and PG&E Peninsula North/ PGP1) (current PGE2 demand zone)*
			PGDI	*Diablo (PG&E Diablo/ PGDI)*
			PGEB	*East Bay (PG&E East Bay/ PGEB)*
			PGMS	*Mission (PG&E Mission/ PGMS)*
			PGSJ	*San Jose/ Peninsula (PG&E De Anza/ PGDA, PG&E Peninsula South/ PGP2, and PG&E San Jose/ PGSJ)*
			PGF1	*Fresno (PG&E Fresno North/ PGF1, and part of PG&E Yosemite/ PGYO)*
			PGNC	*North Coast (North Bay LPA portion of PG&E North Coast/ PGNC)*
			PGFG	*Fulton Geysers (Fulton Geysers LPA portion of PG&E North Coast/ PGNC)*
			PGBC	*Battle Creek LRA (RMR area in PG&E North Valley/ PGNV)*
			PGSI	*Sierra LRA (RMR area in PG&E Sierra/ PGSI and parts of PG&E Sacramento/ PGSA)*
			PGST	*Stockton LRA (RMR area in PG&E Stockton/ PGST and Stanislaus/ PGSN)*
			PGNB	North Bay (PG&E North Bay/ PGNB, and remaining portion of PG&E North Coast/ PGNC)
			PGNV	North Valley (remaining portion of PG&E North Valley/ PGNV)
			PGSA	Sacramento Valley (remaining portions of PG&E Sacramento/ PGSA and Sierra/ PGSI)
			PGSN	San Joaquin (remaining portions of PG&E Stockton/ PGST, PG&E Stanislaus/ PGST, and PG&E Yosemite/ PGYO)
			PGCC	Central Coast (PG&E Central Coast/ PGCC)
			CT1	California Oregon Transmission Project
			CSF1	City of San Francisco
		CWR1	CWR1	California Dept. Of Water Resources
			CWR4	California Dept. Of Water Resources
		LMD1	LMD1	Lassen Municipal Utility District
		MID1	MID1	Modesto Irrigation District
		NCP1	NCP1	Northern California Power Agency (includes City of Santa Clara)
		RED1	RED1	City of Redding
		SMD1	SMD1	Sacramento Municipal Utility District
		TID1	TID1	Turlock Irrigation District
		WAP1	WAP1	Western Area Power Administration
	ZP26	PGE4	PGLP	Los Padres (PG&E Fresno South/ PGF2, PG&E Kern/ PGKE, and PG&E Los Padres/ PGLP)
		CWR2	CWR2	California Dept. of Water Resources
			CWR5	California Dept. of Water Resources
		NCP2	NCP2	Northern California Power Agency
SCE	SP15	SCE1	*SCSO*	*LA/ Orange County (SCE South/ SCSO)*
			SCEA	Other SCE (SCE East/ SCEA, SCE High Desert/ SCHD, SCE North/ SCNO, SCE Sylmar/ SCDC, and SCE West/ SCWE)
		ANA1	ANA1	City of Anaheim
		CWR3	CWR3	California Dept. of Water Resources
			CWR6	California Dept. of Water Resources
		PAS1	PAS1	City of Pasadena
		RVD1	RVD1	City of Riverside
		VRN1	VRN1	City of Vernon
		Other ...	Other ...	Load Groups for other municipal utilities?
SDGE		SDG1	*SDG1*	*San Diego Gas and Electric*

57 Areas within LPAs defined in the CMR project, and LRAs defined by RMR requirements, are shown in italic font.

5.8.2.2 Accommodation of Demand Side Bidding

FERC's standard market design places significant emphasis on demand responsiveness. In general, the MD02 process has identified a number of features that facilitate demand responsiveness, which are discussed in other sections and summarized in Section 5.8.3. The primary implication of the initial 9/30/02 market changes is that voluntary three-part bids (equivalent to start-up and minimum-load costs, and energy bids) would be submitted to the RUC process. A bid for demand response does not need to use multiple bid components, but can do so at the option of the bidder. Because actual costs, similar to start-up and minimum-load costs of generators, can be incurred by Participating Loads but would be difficult for the ISO to verify, the three-part bids submitted by Participating Loads will be market-based and not require verification of actual costs. Instead, the bids submitted by loads will need to compete with generation for dispatch through the RUC process, and ultimately in the forward and real-time energy markets. This will ensure the most comparable treatment that can feasibly be provided between load and generation resources.[58]

[58] Examples can illustrate how equivalents of start-up and minimum-load costs promote comparable treatment of load and generation resources. If a load has a recovery time after a curtailment before it can be back in operation, which is independent of how long the curtailment lasts, it could bid a start-up cost equal to its energy bid price times that recovery time. A load that needs two hours to restart its industrial process after a curtailment ends, regardless of the length of curtailment, could thus be compensated for a minimum of its recovery cost plus 0.5 hour of dispatched operation for a 30-minute curtailment, and for a minimum of its recovery cost plus 4 hours of dispatched operation for a 4-hour curtailment.

As with a generator, its cost recovery would be for market revenues plus any net-of-market start-up and minimum-load cost. If the load is un-dispatched after one hour but its bid has a minimum 4 hours "run" time plus a "start-up" cost equal to 2 hours recovery time times its energy bid, it would also have a minimum cost recovery equivalent to 6 hours times its bid price. In this example, if its bid price is $50/MWh plus its start-up cost and the market clearing price (MCP) from 1 to 2 PM is $200 and $40 from 2 PM to 5 PM, it would be assured of least $300/MW of cost recovery (6 hours times $50) but would have received $320/MW in market revenue (1 hour at $200, plus 3 hours at $40), so it would receive no additional revenue to cover its "startup" cost. At a lower MCP, there may be assured cost recovery that would be charged to the market as an uplift. This is the same cost recovery as a CT that bid $50/MWh, and has a 4 hour minimum run time and a $100/MW startup cost.

The intent is to provide flexibility to loads in being dispatched in competition with other resources. In the above example, the load could bid a $300/MW start-up cost, $0 minimum load cost, and a $0 energy bid that covers a 6-hour block time period, with the same result. The load could also use a minimum run time (i.e., minimum time off-line), instead of a fixed start-up cost, if it can perform its recovery during the curtailment and thus have a shorter recovery time after a longer dispatch. Alternatively, the load could bid a minimum-load cost per hour to curtail at all, and bid a different energy price for additional load shedding. Providing this flexibility to the LSE will be essential, and verification increasingly difficult for the ISO, in cases where the LSE uses an aggregation of load resources (e.g., air conditioning cycling on small end-use customers, combined with management of an industrial process) to support its bid.

In all the cases, the dispatch would have considered what is the most economical way of serving the overall energy need, and would dispatch the load resource if it were cheaper in total than other resources, including its startup and minimum-load cost. This will place a practical limit on loads bidding excessive start-up and minimum-load costs, since excessive bids could mean that the load resource would never be dispatched.

However, because the primary purpose of scheduling load is to satisfy needs other than energy production (i.e., load uses energy to serve other purposes), load resources should not be subject to the must-offer obligation to bid into the RUC process, unless they are providing ACAP. In other words, the bidding of non-ACAP Participating Loads into the RUC process should be voluntary.[59]

The scheduling and settlement of load offers additional opportunities for response to day-ahead and hour-ahead energy prices. In addition to allowing loads to submit bids for dispatched "Participating Load" at either the bus or load aggregation level, loads can be price-responsive to locational prices through aggregated scheduling. If a LSE serves customers who it believes will adjust their load based on forward energy prices, it can include an energy bid curve in its load schedule. Deviations from the resulting energy schedule would then be settled at the real-time energy price.

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 would be allowed to 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 can be locational, bids that are eligible for real time dispatch (ancillary service and supplemental energy) would need to be bid at the load group or node.

5.8.2.3 Aggregated Distributed Generation

This section anticipates that market participants may view small, distributed generation as equivalent to negative load. The ISO's recently announced Aggregated Distributed Generation Pilot Project allows generators under 1 MW to be aggregated by demand zone, although the specific locations of significantly-sized generators that make up the aggregations would be known. Although separate aggregations would need to be maintained to appropriately track (a) energy flows on the ISO grid and (b) settlements that distinguish between load and generation, the aggregation of distributed generation appears sufficiently similar to the LSE-specific aggregations of load, as included in the ISO's proposal, that additional provisions do not appear necessary.

5.8.2.4 Bilateral Schedules and Load Following

Some SCs have both resources and loads that they wish to match with each other as a balanced schedule, while other SCs may have contractual commitments for specific performance of particular resources through bilateral schedules. SCs have also expressed a desire to use their own resources, including contracts with other suppliers, to follow their own load variations. Options for bilateral schedules, as discussed in other sections, and the revised timeline for the hour-ahead market, of the ISO's Comprehensive Design proposal provides this ability while assuring the ISO of sufficient knowledge of system operations to maintain reliability.

[59] While interruptible load is expected to comply with curtailments that are initiated by the ISO, these curtailments are based on reliability needs and are not evaluated on an economic basis or considered in the RUC process. Methods for incorporating interruptible capacity in ACAP requirements would be considered in designing the ACAP process.

5.8.3 MD02 Options for Demand Response

In the March 2002 "Working Paper on Standardized Transmission Service and Wholesale Electric Market Design" (at p. 6), FERC states: "Demand response is essential in competitive markets to assure the efficient interaction of supply and demand, as a check on supplier and locational market power, and as an opportunity for choice by wholesale and end-use customers." The ISO fully supports this role for demand programs, and has considered this need throughout the MD02 design. The ISO's Participating Load Program already meets most of the principles for demand participation outlined in the Standard Market Design document, and Section 5.8.2.2 presents ISO proposals to enhance demand response.

Market Design 2002 (MD02) proposals in other sections further demonstrate the ISO's commitment to demand programs as a vital ingredient for Load Serving Entities (LSEs) to meet their capacity obligation and meet their customers' needs. The implementation of retail demand programs is ultimately the responsibility of LSEs and state agencies, but the ISO is supporting these programs by establishing needed market infrastructure and incentives.[60] When viewed in the context of a capacity obligation, the new ISO design including a capacity obligation will place additional financial incentives on LSEs to develop these programs to reduce their costs. The ISO's proposals also provide improved opportunities for load to respond to prices in the ISO's markets, and to participate as resources that augment supply resources. These opportunities include:

- Eligibility as an ACAP resource, which can receive a capacity payment, or allow a LSE to avoid paying another supplier for ACAP capacity.
- As an ACAP resource, ability to recover "start-up" and "minimum-load" costs through Residual Unit Commitment. However, 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.
- 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 load can say through its bid that it will reduce its normal energy use if it would need to pay a higher-than-normal price – or that it will use additional energy if it is available at a lower-than-normal price. Currently, loads can deviate from their schedules and be paid as uninstructed deviations at real-time prices, but the real-time prices can be unpredictable from the customer's perspective. Thus, the new Day-Ahead market offers new opportunities for response at a known price.
- Hour-Ahead energy market, allowing price responsiveness to be offered when permitted by daily conditions, if curtailability is uncertain in the Day-Ahead timeframe.
- Revised Hour-Ahead timeline also improves a LSE's ability to operate its own load management programs, and to reflect this event through a revision to its HA-scheduled load. Allowing schedule revisions closer to the operating hour will enhance participating loads' ability to respond to both real-time system needs and their own operating needs.

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[60] 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 CPUC provide an option for real-time pricing, which allows the IOU to pass through some type of charge or credit in addition to the bundled customer's retail rate.

- Participation in the Real-Time market, receiving the RT price with ability to be pre-dispatched in competition with other inflexible resources like inter-ties and CTs, assurance of recovering cost-based start-up costs and a minimum of its bid price for energy, and operation for a minimum run time.
- Ability to receive the Real-Time price during the highest-cost intervals by a cycling response by 10-minute interval, for resources that can offer such response.
- Ability to offer response to locational price variations through DA, HA, and RT energy markets.
- Continued ability to participate in Ancillary Service 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) and waiver of telemetry requirements for supplemental energy. Only interval metering and ability to receive dispatch instructions is 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.
- Loads or aggregated load entities must execute a Participating Load Agreement (which may need to be modified to define contractually firm demand programs if they wish to quality for ACAP). This establishes sound mechanisms for settlement flows from the ISO to Scheduling Coordinators, which then allows settlement with LSEs and ultimately with end use loads.

5.8.4 Alternatives Considered

This section revisits the ISO's overall proposal, to describe the considerations that led to its formulation.

5.8.4.1 Appropriate level of aggregation

The considerations in selecting the highest allowable level of aggregation for scheduling and settlement of load can be examined by comparing a range of alternatives to the ISO's proposal:

- Option A: Schedule and settle most load by broad areas (PG&E, SCE, and SDG&E transmission service areas, including smaller service areas located within the broader areas).
- Option B1: Schedule and settle load at an aggregated level that is smaller than transmission service areas.
- Option B2: Schedule and settle load at an aggregated level as in B1, and keep LSEs financially neutral to settlement by congestion zone or IOU service area by an allocation of the benefits from FTRs. (Details of how these "benefits" would be allocated are considered in Section 5.8.4.2.)
- Option C: Schedule and settle load at the nodal level.

<u>Option A:</u> Representatives of areas that are likely to have high LMPs argue that they are adversely affected by historical decisions on generation and transmission planning that were made during a time when locational price differences have not had the significance that they would under locational pricing, and therefore that they would be unfairly impacted by locational

pricing. That is, they argue that large utilities have historically made their planning decisions to minimize the cost of serving their entire transmission service areas, with no reason to consider equity issues that would result from a pricing system that was not in use at that time. The controversy of equitable treatment given historical planning decisions could be avoided by allowing all loads to schedule and be settled at a comparable level such as the service area of the investor-owned utilities (IOUs). Drawbacks of this option, however, are that it does not promote locational accuracy in scheduling and eliminates pricing incentives that locational pricing seeks to provide: pricing load based on the IOU's transmission service area provides, at best, limited incentives for load to invest in local transmission upgrades and does not allow load to respond to variations in the cost of energy over time that differ from the average for the service area.

Options B1 and B2: Another option is for loads to schedule using a "load aggregation" as defined in Section 5.8.2.1, as a way of promoting accuracy in scheduling – discussed here as Option B1.[61] To compare this to other alternatives, it is useful to examine how Load Distribution Factors (LDFs) would be used.[62] Load would be scheduled by the LSE at the aggregated level, and LDFs would allocate the loads scheduled at aggregated levels to buses, based on recent load levels at the buses. LDFs would be calculated for day type (e.g., weekday versus weekend-holiday) and time of day (e.g., peak and off-peak). The LDFs would then be used as weighting factors to calculate an average price, for settlement of loads that were originally scheduled at these levels. Usage of energy and other services would be charged the weighted average price. Meaningful load aggregations for purposes of Option B1 would identify areas with similarly-priced buses, so aggregation at this level would present the equity issues that Option A sought to avoid. To the extent that a UDC serves load in areas with different prices, its retail rate design could average the prices across its service area, but a UDC with a small service area could not do so.

A solution to this equity issue could be to combine scheduling of loads at an aggregated level, with allocation of the benefits associated with FTRs from a broadly aggregated area (a "hub") to the load aggregation – discussed here as Option B2. (Similarly, loads scheduling at the bus level in Option C could be given FTRs from the hub to the bus.) This would make loads financially neutral to scheduling at a (hub) level that is familiar (e.g., NP15 or SP15) with no adverse impact from the ISO going from the current zonal model to a full network model. This could also offer flexibility from being able to trade their FTR if they wish. The same benefit is reflected in the ISO's proposal. It is possible, however, that simply giving something of financial value to specific market participants would raise its own set of controversies - although these may be minimized by FERC's recent working paper on standard market design, which supports allocating FTRs (or auction revenues from FTRs) to customers that pay the embedded costs of the system (e.g., loads).

Option C: Even greater detail would be provided by scheduling and settling at the nodal level. Concerns that would need to be addressed by establishing this granularity include whether LSEs would be able to schedule accurately at this level and whether unstable pricing would result from small inaccuracies in network modeling. The ISO's past experience is that UDCs can have trouble accurately scheduling at a lower level than their total service area, and UDCs

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[61] It is important to not confuse the areas that are established for meaningful scheduling of load with the Local Reliability Areas (LRAs) that may be established as part of ACAP and/or RUC procurement. LRAs may be among the areas that define standard load aggregations for scheduling, but these areas may also be established to reflect boundaries between UDCs or to reflect differences in congestion costs.

[62] LDFs would also be used in Option A.

at the ISO's MD02 focus group meetings stated that they would need time to develop business systems that could implement scheduling and settlement for smaller areas than their total service area.

These concerns about the ability of UDCs to schedule at a lower level than their entire service area have led to structuring the ISO's proposal using load aggregations, initially including areas similar to Demand Zones, since the existing Demand Zones generally correspond to UDC boundaries. This recommendation is also strongly influenced by a conclusion that the tradeoffs of cost exposure, feasibility, and accuracy are best balanced by an alternative that is in the middle of the extreme options. Over time, the obstacles to scheduling at lower levels can be overcome, and greater accuracy in system operation achieved by doing so -- thus scheduling and settlement will eventually phase out the broader load aggregations.

The above comparisons are summarized in the following table.

Alternative	Pros	Cons	Implementation Considerations
ISO Proposal: Load schedules & settles by load aggregation. Cost impact to be offset by allocation of FTRs.	Simple. Limits LMP cost to certain loads. Municipal utilities have own load aggregations. Provides choice.	Limits LMP signals	Allows flexibility for scheduling at more granular levels than the default aggregation. SCs may continue scheduling at current levels, and be mapped to aggregated level.
A: Load schedules & settles by IOU service area	Simple, limits LMP cost to certain loads	Eliminates most LMP signals to loads	SCs may continue scheduling at current levels, and be mapped to aggregated level
B: Load schedules & settles by load aggregation	Retains some LMP signals	Limits LMP signals. Seen as unfair unless given FTR	New needs for detail and consistency in scheduling & settlement may add to implementation time, if at load group
C: Load schedules & settles by node	Strongest and most precise LMP signals	Seen as unfair unless given FTR	New needs for detail and consistency in scheduling & settlement may add to implementation time

5.8.4.2 Allocation of FTRs to Loads

Because equity issues due to cost impacts are inherently part of the comparison of alternative levels of aggregation, the above discussion has included the parallel issue of using FTRs to achieve financial neutrality among the options. In the course of developing this proposal the ISO considered a number of ways to mitigate the impacts of LMP on loads. One alternative to allocating FTRs to LSEs may be to provide a separate settlement scheme that would ensure the LSE remains financially neutral to congestion charges within a broad area such as a congestion zone. For example, a limit to each LSE's cost exposure could be determined, and congestion costs beyond that amount could be treated as an uplift instead of being settled as a congestion charge to that LSE. This alternative, however, increases the complication and reduces the transparency of the congestion settlements and may result in revenue neutrality issues. The resolution of FTR allocation issues is presented in Section 5.3, and the following discussion in included here to describe the ISO's considerations in developing its proposal for load scheduling and settlement.

As to the mechanics of achieving financial neutrality to scheduling and settlement at a broadly aggregated area, the discussion above has been intentionally vague as to the meaning of "allocation of benefits from FTRs." This is because the desired result may be achieved in more than one way, without affecting the conclusions stated above. One method would be to give FTRs to the LSEs that serve load in each load aggregation, although this could conflict with an issue considered in other areas of the MD02 market design of whether to ensure that the FTR auction is able to compare the values placed on FTRs by all market participants, by awarding the ownership of all FTRs through the auction process.

An alternative for ensuring that LSEs are financially neutral between locational pricing and pricing at a broad aggregation of buses is through an allocation of FTR auction proceeds (see Section 5.3). The amount to be allocated that affects the issues addressed here is the number of MW associated with FTRs whose destination is within the load aggregation, times the price differential from the surrounding hub (a broadly aggregated area, i.e., NP15, SP15, or ZP26).[63] The following example illustrates how an allocation of FTR auction proceeds would protect a LSE financially (assuming it is the primary LSE in its load aggregation). If the LSE expects the value of congestion costs, over the period covered by the auction, from its hub to its load aggregation, to be $1000, it can pay $1000 in the FTR auction and receive the $1000 as its share of the auction proceeds, thus being financially neutral. If another FTR auction participant bids $1500, the LSE can (1) choose to let the other market participant win the auction, (2) receive the $1500, (3) probably pay $1000 for congestion costs during the term of the FTR if its expectations are correct, and (4) thus profit by the difference of $500. If the LSE is particularly risk adverse despite its expectation of paying $1000 in congestion costs, it could continue to outbid the other auction participant and remain financially neutral by receiving the same amount that it pays to win the auction – if it needs to pay $2000 to win the auction, it will receive the $2000 as its share of auction proceeds and thus remain financially neutral, with the consequence that it sacrifices the opportunity to receive the net $500 if it had let the other participant win the auction.[64]

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[63] FTRs have been proposed in other issue areas of MD02 to include both (a) Point-to-Point and (b) Point-to-Hub/ Hub-to-Hub/ Hub-to-Point FTRs. In structure (b), both the quantity and the value of FTRs are the Hub-to-Point portion. For the purposes of this issue paper, the pricing aspects of structure (a) can be conceptually broken down to the pieces that make up structure (b), with the same quantity of MW applying to each piece and the price of the Hub-to-Point piece being equal to the price of the Hub-to-Point FTR (where the applicable hub is the one that contains the demand zone, among the choices of NP15, SP15, and ZP26). Thus, the accounting considered here can be accomplished as the product of the MW of combined FTRs times the value of the Hub-to-Point FTR.

[64] A different situation occurs when likely differences between LMPs would create a financial obligation to the FTR holder, if FTRs are only offered as obligations (not as FTR options). If the expected value of an FTR is expected to be $-1000 instead of a positive $1000, an LSE service load in the affected

In addition, the presence of ETC rights insulates some LSEs from locational price variations. In comparing the options of allocating FTRs or FTR auction proceeds among LSEs to the status quo, which initially allocates the FTR auction proceeds to the Transmission Owner (TO), it must be recognized that the existing process actually awards the auction proceeds uniformly to load that receives transmission service from the TO, and that the TO does not receive any additional revenue from the current allocation of FTR auction proceeds, or from the congestion revenues from transmission rights that are beyond the quantity that is auctioned. The reason why the status quo actually is a uniform allocation across all transmission users is that the FTR auction proceeds, and any additional congestion revenue received by the TO from capacity that is not auctioned, serve to reduce the TO's Transmission Access Charge (TAC). Although the settlement process initially assigns the FTR revenues to the TO, the TO's gross income does not change, and the benefit is received by everyone who pays the TAC, albeit with a year's delay due to the accounting mechanisms.

Ultimately both alternatives allocate the auction proceeds to users of the transmission system; the issue is how the benefits are distributed to consumers at different locations in that system.

5.8.4.3 Alternative levels of aggregation

As noted above, scheduling and settlement at an aggregated level involves averaging of nodal prices to compute aggregated prices for each load aggregation, using LDFs. For the standard load aggregations defined in Section 5.8.2.1, the ISO anticipates computing seasonal on-peak and off-peak LDFs, which will be placed in files for download from OASIS.[65] Extension of this process offers a way to achieve the benefits of both the more granular levels of scheduling (i.e., precision in locational pricing, and incentive for investment in relieving transmission constraints) and the more aggregated levels (i.e., feasibility of implementation), by allowing LSEs to choose the level at which they schedule. (If a load elects to schedule at lower than the default level, the ISO may determine that it should be omitted from calculation of LDFs for the broader area where it is located, unless it later elects to be scheduled again at the aggregated level.)

Because the LDFs are simply a tool used in calculations, aggregations of load points can be discontiguous (e.g., the existing NCPA, CDWR, and WAPA load groups). Section 5.8.2.1 provides a standard set of aggregations, but the same concept can be used to facilitate scheduling by LSEs (for example, ESPs) whose customers' locations do not align with the standard load aggregations. LSE-specific aggregations can be established provided that scheduling and reporting of load are required to be at the same locations, and generally that consistency and auditability for reporting actual usage are provided.[66] This process of using

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load aggregation could submit a bid in the FTR auction saying that it would need to be paid at least that amount to accept the FTR obligation. Thus, the LSE can avoid being adversely affected.

65 The LDFs will represent the total MWh of load at each bus, minus the load that has historically been scheduled at the nodal level or in non-standard aggregations if this significantly affects the calculation. LDFs are used to allocate load from a high geographic level (e.g., a demand zone) to a more granular level (e.g., a bus). The high-level load may have come from various sources (e.g., an hourly load forecast), but the LDFs do not allocate load over a period of time to a more granular time of use. As it performs Residual Unit Commitment, the ISO may use these LDFs or other LDFs that are based on more recent or more detailed information. The ISO also recognizes the need to allow for non-conforming loads, i.e., loads that do not bear a well-defined relationship to the total load in the demand zone or load group, and will address this issue in developing the Tariff language to be filed in support of this proposal.

66 The required level of verification can depend on the impact of the load that is scheduled. Current verification requirements are telemetry for Participating Load that provides non-spinning reserve or replacement reserve, but only interval metering and ability to receive dispatch instructions if

non-standard load aggregations needs to be sufficiently flexible to accommodate occurrences including end-use customers switching between competing retail Energy Service Providers (ESPs) or other LSEs. Also, ESPs have the ability to change SCs, and do so as their business needs determine. Thus, a non-standard load aggregation may need to be associated with the LSE rather than the SC, so that the SCs can correctly track settlements for the LSEs.

A non-standard load aggregation would be established upon request of a LSE (including ESPs), who would provide the Universal Node Identifier (UNI) of the participating end-use customers in CPUC-jurisdictional service areas, or similar site identifier in other areas. (In CPUC-jurisdictional areas, the UNI is communicated to the ESP by the UDC when a customer signs up for Direct Access, per existing CPUC decisions. For a metered subsystem that has a limited number of takeout points from the ISO grid, identification of the takeout point may be all that is required.) The UNI will allow the ISO to track MWh usage, recompute LDFs when customers switch between load aggregations, and ensure that all customers are served by one and only one SC.

A non-standard load aggregation would not be able to cross certain boundaries that will be designated by the ISO. Initially, these boundaries are Path 15 and Path 26.

For non-standard load aggregations, LSEs will provide the set of LDFs to the ISO that should be applied to the scheduling of their load. A LSE may update its LDFs as often as once per day, but may leave a submitted set of LDFs in place for up to one year. This allows a LSE to reflect changes in the quantities and distribution of the end-use loads that it serves.

Initially, these non-standard load aggregations, as well as scheduling at the nodal level, will allow flexibility in scheduling but will not be able to affect settlements for load, which will need to be priced at a broad level of aggregation (including the PGE3 and SCE1 load aggregations). Settlement of load at a nodal level (and non-standard aggregations that include the nodal level) would require a large volume of meter data that the ISO believes is currently beyond the ability of market participants to validate and submit within the settlement period, and that would also be difficult for the ISO to audit. Ultimately, settlement at the nodal level may need to be done between UDCs and LSEs that serve load within their service areas, but this process will require arrangements that would be developed cooperatively between the ISO, the UDCs, LSEs, the CPUC, FERC, and possibly other parties. The structures described herein will facilitate the development of these processes, but their implementation must be deferred to a future date.

5.8.5 Conformance with FERC Standard Market Design

FERC Standard Market Design	***ISO Proposal***
Allow demand bids to place value on energy	Yes
Equal opportunities for demand and supply resources	Yes
Price signals reflect time and locational value of energy	Yes
Multi-part demand-side bids, including time constraints	Yes
Demand resources able to participate in real-time market	Yes
Allow bilateral schedules and self-supply	Yes

supplemental energy is provided. By extension, interval metering would be required for response to hourly prices through forward scheduling, and monthly metering with load profiling would be sufficient for loads that are scheduled at load group or nodal levels with no price responsiveness.

5.9 Bid Mitigation for Local Reliability Needs

5.9.1 Introduction

FERC has recognized on numerous occasions that generators that are needed for local reliability purposes have locational market power.[67] Accordingly, FERC has granted certain mitigation measures against local market power to the other ISOs.[68] The ISO's comprehensive market design slated for implementation in 2003 includes such mitigation in both the forward and the real-time markets. Given that FERC has approved local market power mitigation measures for other ISOs, it is only appropriate that FERC approve similar measures for the ISO.[69]

5.9.2 ISO Proposal

Forward market mitigation of incremental bids that are needed out of economic merit order for local needs, follows the same logic and principles regardless of granularity of the underlying network model used. Regarding local market power in the decremental bid market, it is a known fact that nodal pricing will provide a natural mitigation in the first settlement market (i.e., the day ahead). However, short of strict activity rules (such as precluding bidders from submitting revised decremental bids after the close of the day ahead market), local market power in the supply of decremental bids can emerge in the subsequent markets, again regardless of the granularity of the underlying network model. Such activity rules can be implemented when the ISO starts a forward energy market but would need to be supplemented with bid mitigation rules for incremental bids. Alternatively, the ISO could simply adopt bid mitigation rules for both incremental and decremental bids in situations where resources are situated to exercise local market power. The ISO has selected the latter approach.

Specifically, when the ISO adopts a full network model in the day-ahead and real-time markets, it will initially define competitive regions that are comprised of the following existing internal zones: NP15, SP15, and ZP26 in combination with either NP15 or SP15. Local market power mitigation measures will apply anytime the ISO has to dispatch resources in either the day-ahead, hour-ahead, or real-time market out of merit order within one of these zones.[70] In such cases, resources will be subject to unit-specific bid caps that will be based on the following criteria, listed in order of preference depending on the availability of information: (1) the unit's variable cost for gas-fired units; for all other resources, the lower of the mean or median of the resource's market-based bids during the previous 90-days when the unit was dispatched in economic merit order; (2) a weighted average of the appropriate competitive region (i.e., zonal)

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67 See PJM Interconnection, L.L.C., 96 FERC ¶61,233 at 61,936 (2001); AES Southland, Inc. et al., 94 FERC ¶61,248 (2001).

68 See, e.g., New England Power Pool, 91 FERC ¶61,193 (2000) (accepting Amended Rule 17 whereby out of merit dispatch is flagged and subject to several screens before payment); Atlantic City Electric Company, et al., 86 FERC ¶61,248 at 61,898-903 (1999). However, FERC has not approved similar local market power mitigation measures for the ISO.

69 Although the ISO does have certain existing measures to mitigate the exercise of locational market power (i.e., RMR contracts), these measures do not provide complete protection from such exercise. The ISO needs local market power mitigation measures similar to those FERC has granted to other ISOs.

70 A bid in ZP26 would be considered out of merit order if it is out of merit order in both ZP26+NP15 and ZP26+SP15 combinations.

prices during the previous 90-days when the resource was dispatched in economic merit order, or (3) a pre-negotiated price. As the ISO gains more experience under the nodal market structure, it may define smaller competitive regions if it determines, based on an assessment of historical bidding patterns, that such regions could be workably competitive.

5.9.3 Comparision With Other ISOs

The ISO's proposed approach is consistent with the PJM market, which uses unit-specific bid caps for units dispatched out of merit order due to congestion, if the commissioning of the unit commenced before July 1996 (which includes the majority of the in-control area units).

In ISO NE, structural and price screens are used to determine whether or not to invoke mitigation under congestion conditions. In cases of local market power, the ISO pays a default compensation to generators based on a mitigated price. The mitigated price is based on short-run marginal costs; however, generators are allowed the opportunity to demonstrate cost data to support a higher level of compensation.

In certain cases, the ISO NE has agreed to pay more than short-run marginal cost to ensure that certain generators remain in existence. In those cases the ISO agreed to pay a mitigated price equal to the sum of average fixed costs plus variable operating costs. The ISO NE considers legitimate opportunity costs for limited energy resources and has used options contracts as a proxy for a fair peak seasonal price for these resources.

In NYISO, mitigated bid caps are used for congestion constrained areas, if constrained nodal prices exceed the price at a relatively unconstrained node (Indian Point) by more than 5%.

To enable proper generation allocation to the New York County, the day-ahead SCUC process requires a certain percentage of the units to be on in a certain voltage class. SCUC will commit additional units in its Pass 3 (i.e., after allocating competitive bids without regard to local reliability needs) to meet this requirement at minimum additional commitment cost (start-up cost + minimum generation cost). The uplift to meet local reliability requirements is charged to the loads within the zone where local reliability requires the incremental commitment.

5.10 Damage Control Bid Caps on ISO Markets

5.10.1 Introduction

Without the price mitigation provided by the FERC market mitigation orders, the spot markets will be vulnerable to extreme peak prices. All other ISOs have some level of damage control bid cap (DCBC) to limit the adverse cost impacts of an unusually severe price spike. Although the eastern ISOs have a DCBC of $1000 per MWh,[71] the ISO does not believe this is an appropriate level for the California market due to the fact that the structural elements necessary to ensure a workably competitive market are not in place, and as a result a DCBC will likely be hit more frequently than in the eastern ISO markets.

[71] In addition PJM has a bid cap of $100/MW/hr on Regulation capacity bids, and NYISO has a bid cap of $2.53/MW/hr on 10-minute Non-spinning operating reserve bids.

5.10.2 ISO Proposal

To mitigate against excessive market power abuse, the ISO proposes a Damage Control Bid Cap (DCBC) that will limit the maximum bid allowed in the ISO's energy and ancillary service capacity markets. Since the Available Capacity (ACAP) Obligation will not be implemented in the near term, to protect against market power in the transitional period, the ISO believes it is prudent to start with a relatively low bid cap and gradually raise it as capacity conditions improve. The bid cap would apply to all resources submitting bids in the ISO markets (including imports) and the same bid cap would apply to both energy and ancillary service capacity.

Beginning on October 1, 2002 and continuing until market conditions are competitive enough to support a higher Damage Control Bid Cap, the ISO proposes to set the DCBC at the current level of $108 per MWh, and to raise the DCBC as appropriate when the price of natural gas increases, in accordance with the formula approved by FERC for use today in conjunction with the existing mitigation provisions.[72] In addition, the ISO proposes to raise the DCBC over the long term as ACAP is implemented and as the competitiveness of the ISO markets improves.

The ISO realizes that recent and past experience has shown that the ISO's bid cap tends to create a target for supply bids in the ISO's real-time market, and that recent analysis of the ISO's real-time market has shown that some suppliers tend to consistently bid a significant share of their available capacity at or near whatever level the ISO has set as a bid cap, regardless of the unit's actual variable cost. The ISO believes, however, that the bid screens and mitigation provisions described in the next section will address this concern. Under the proposed bid screens and mitigation provisions only resources with extremely high bid reference levels will be able to effectively bid at or near the DCBC.

The ISO plans to increase the level of the DCBC over time as the structural elements necessary to support a competitive market improve (including a transition to a full ACAP obligation) and believes that the DCBC could eventually be increased to $1,000/MWh, which is the bid cap level currently in place in the eastern ISOs. However, the ISO does not believe it is appropriate to set specific dates for when the DCBC would increase because such dates would be arbitrary. The decision to raise the DCBC will be based on an assessment of overall competitiveness of the market rather than an arbitrary date.

For negatively priced Energy and Ancillary Services bids a bid cap of -$30 per MWh will apply system-wide. Negatively priced bids may be subject to further mitigation (per Section 5.9) in cases where local market power mitigation is applicable.

For Adjustment Bids used in forward congestion management, while the Market Separation Rule is in place, the lower and upper bounds on the Adjustment Bid prices are $0/MWh and $250/MWh respectively. Unused Adjustment Bids will then be further capped for local market power mitigation before they are used for real-time intra-zonal congestion management. When the ISO starts its forward energy market (and the Market Separation Rule is eliminated) the Adjustment Bid caps in both positive and negative price directions will be the same as the energy and A/S bid caps.

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72 The proposed DCBC would be a hard cap (i.e., bids above the DCBC would be rejected rather than accepted subject to justification as they would be under a soft cap), and the $108 per MWh value would represent a floor in the sense that the cap could increase but not decrease in response to gas price movements. The applicable methodology for adjusting the DCBC is described in FERC's December 19, 2001 "Order Temporarily Modifying the West-wide Price Mitigation Methodology."

5.10.3 Comparision with Other ISOs

All ISOs have maximum bid limits in their markets. The eastern ISOs (PJM, NY, NE) have $1,000/MWh bid caps in their markets. The CAISO plans to eventually transition to a comparable level as the structural elements necessary to support a workably competitive market improve.

5.11 Bid Screens and Mitigation

5.11.1 Introduction

This element is intended to protect against certain types of anti-competitive bidding behavior. FERC has already recognized certain types of anti-competitive bidding behavior. For example, in its April 26, 2001 Order, FERC conditioned public utility sellers' market based rates on not engaging in the following types of bidding behavior.

1. Bids into the ISO markets that vary with unit output in a way that is unrelated to the known performance characteristics of the unit (also known as "hockey stick" bidding).
2. Bids into the ISO markets that vary over time in a manner that appears unrelated to change in the unit's performance or to changes in the supply environment that would induce additional risk or other adverse shifts in the cost basis.

Under the April 26 Order, market participants engaging in this type of behavior are subject to increased scrutiny by the Commission and potential refunds, and could have their market-based rate authority subject to further conditions, including prospective revocation of market-based rate authority. To carry these provisions forward beyond September 30, 2002 and make them more enforceable, the ISO proposes to seek authority, similar to what FERC has granted to the NY ISO, to mitigate a suppliers bids automatically when a supplier's bidding behavior (a) violates explicit anti-competitive thresholds, and (b) has a material impact on market prices.

5.11.2 ISO Proposal

The ISO proposes to implement individual resource bid screens and mitigation in the Day-ahead and Hour-ahead energy markets (to take effect when the ISO implements these markets) and the ISO's real-time energy market. This approach would be very similar to the bid mitigation approach that the New York ISO uses to automatically mitigate bids under predefined circumstances in its Day-ahead energy market. For the October 2002 implementation, since the ISO will not run a forward energy market, the ISO proposes to implement this feature in the Residual Unit Commitment instead. Moreover, due to difficulty of implementing it in a 10-minute dispatch time frame starting October 2002, the ISO proposes to apply this measure also in the real time pre-dispatch time frame. The AMP will not be applied, however, if the ISO's day-ahead load forecast exceeds 40,000 MW.

In the NY ISO, economic thresholds for energy bids are set with respect to a resource specific reference level, which is based on the resource's historical competitive bids during similar hours and load levels and adjusted for fuel prices. The bid threshold used by the NY ISO is an increase of 300% from the reference level or $100/MWh, whichever is lower. Similarly, the NY ISO also uses a fairly generous threshold to determine whether the bids had a "material price effect." For example, the energy market impact threshold used by the NY ISO is whether the bidding behavior resulted in an increase of 200% or $100/MWh, whichever is lower, in the hourly day-ahead or real-time energy Location Based Marginal Price (LBMP) at any location.

Under the NY ISO bid screen and mitigation approach, if a supplier's bids were found to (a) violate explicit anti-competitive thresholds, and (b) have a material impact on market prices, the NY ISO has authority to prospectively impose "default bids" for the supplier for a period of time, not to exceed six months. However, the supplier is still eligible to receive the LBMP. The NY ISO mitigation approach has evolved to the point where they are now able to mitigate bids automatically in their Day-ahead energy market. Under this approach, if the mitigated bids result in a material decline in the LBMP, then the mitigated bids and the resulting LBMPs will serve as the final day-ahead market result. If the mitigated bids do not have a material impact on LBMPs, the original bids and the original LBMPs will serve as the final day-ahead market result. Since this automatic process prevents market impact in the day-ahead market, mitigation is not applied prospectively beyond the current trade day. Prospective mitigation beyond the trade day is reserved for mitigation that cannot be performed before the market is closed, such as mitigation for physical withholding.

5.11.2.1 Mitigation Thresholds

In considering explicit bid thresholds for the California market, the ISO has tried to balance the desire to mitigate anti-competitive bidding behavior with the risk of incorrectly labeling legitimate changes in bidding behavior as anti-competitive. On the one hand, setting thresholds high enough to allow for some price volatility could help further the development of price responsive demand products. Setting the threshold too low will make it difficult to apply AMP to resources that may justifiably have more volatile bidding patterns (e.g., hydro resources whose bid patterns may vary significantly depending on water conditions). Finally, if the AMP thresholds are too restrictive, new generation may choose to locate outside of California.

On the other hand, the ISO does not feel the thresholds developed by the NY ISO are appropriate for the California market. The NY ISO's fairly generous bid and market impact thresholds may be appropriate for markets that are workably competitive most of the time, but the ISO feels these thresholds are too large to provide effective mitigation in the California market, which tends to be significantly less workably competitive.

In balancing these concerns, the ISO proposes the following bid screen and market impact mitigation parameters and thresholds:

ISO Automatic Mitigation Procedures (AMP) Specifications:

AMP Reference Levels

- Based on historical bids for all resources.

AMP Thresholds:

- Bid threshold above Reference Level = Min (100%, $50/MWh) increase from Reference Level
- Price Impact threshold = Min (100% increase, $50/MWh increase)

AMP Applicability:

All resources bidding into the markets to which AMP is applied (including imports), except in hours for which the ISO's day ahead load forecast is greater than 40,000 MW.

An important clarification on the ISO's proposed AMP specifications is that to the extent multiple resources have submitted bids that exceed the respective bid thresholds, they will be mitigated simultaneously to see if they have a material impact on market clearing prices.

As stated earlier, since the ISO will not have a Day-ahead and Hour-ahead energy market in place on October 1, 2002, the ISO is proposing to apply AMP only to the ISO's Real-time Energy Market. Applying an AMP within the Real-time market time frame is problematic, however, because it is simply not feasible to conduct an AMP prior to each 10-minute interval. Instead, the ISO is proposing to run the AMP in a two-stage process. The first run of AMP will occur during the Day-ahead Residual Unit Commitment (RUC) process, which is in effect a day ahead procurement of resources the ISO expects to need to provide real time imbalance energy. During this stage, if energy bids submitted from AMP resources being considered for RUC exceed their bid thresholds, the ISO will mitigate the bids to see if they have a material impact on projected real-time market prices. Real-time prices will be projected based on the ISO's forecast of real-time imbalance demands. If the bids are found to have had a material impact on market clearing prices, the ISO will use the mitigated bids in deciding which additional units to commit for the next operating day. Since the real time prices computed in RUC are advisory, the impact of AMP in RUC is essentially to ensure the ISO does not purchase highly priced imports just because internal resources have submitted high energy bids that may be subject to mitigation in real-time. However, once the ISO has made the commitment decisions in RUC (including commitment to the tie purchases), it will replace the mitigated bids with the original bids in order to conduct a final market impact assessment closer to real-time, as part of the second stage of AMP.

The ISO will run the second stage of AMP 45-minutes prior to the start of the operating hour after all supplemental energy bids are received. During this process, if energy bids submitted from AMP resources being considered for real-time dispatch exceed their bid thresholds, the ISO will mitigate the bids and test to see if they have a material impact on projected real-time market prices. If bids fail the bid-threshold screen and have a material impact on forecasted real-time energy prices, they would be mitigated. Again, if there are multiple bids from multiple resources that violate the bid threshold, they will be mitigated simultaneously to test for market impact.

The ISO intends to extend AMP to the Day-ahead and Hour-ahead energy markets once those markets are implemented. The application of AMP to these markets should be easier to implement than a Real-time market AMP, since there will be more time in the forward markets to run additional procedures. As the ISO gains experience with the bid screen and mitigation procedures and if the overall competitiveness of the ISO markets improves, the ISO will consider raising the bid and price impact threshold levels.

As noted earlier, the AMP will not be applied if the ISO's day-ahead load forecast exceeds 40,000 MW.

5.11.2.2 Reference Levels

a) For purposes of establishing reference levels, bid segments will be defined as follows:

   (1) the capacity of each generation resource shall be divided into 10 equal Energy bid segments between its minimum (Pmin) and maximum (Pmax) operating point.

   (2) for Energy bids submitted over the intertie Scheduling Points (import bids), 10 bid segments shall be established for each Scheduling Coordinator at each Scheduling Point based on historical volumes over the preceding 12 months.

b) A reference level for each bid segment will be calculated for peak and off-peak periods on the basis of the following methods, listed in the order of preference subject to the existence of sufficient data, where sufficient data means at least one data point per time period (peak or off-peak) for the bid segment:

   (1) The lower of the mean or the median of a resource's accepted bids in competitive periods over the previous 90 days for peak and off-peak periods, adjusted for changes in fuel prices;

   (2) If the resource is a gas-fired unit, the unit's default energy bid (based on the incremental heat rate submitted to the ISO, adjusted for gas prices, and the variable O&M cost on file with the ISO, or the default O&M cost of $6/MWh).

   (3) For non gas-fired units, a level determined in consultation with the Market Participant submitting the bid or bids at issue, provided such consultation has occurred prior to the occurrence of the conduct being examined by the ISO, and provided the Market Participant has provided data on a unit's operating costs (opportunity cost for energy limited resources) in accordance with specifications provided by the ISO.

   (4) The mean of the MCP for the units' relevant location (zone or node commensurate with the pricing granularity in effect) during the lowest-priced 25 percent of the hours that the unit was dispatched or scheduled over the previous 90 days for peak and off-peak periods, adjusted for changes in fuel prices; or

   (5) If sufficient data do not exist to calculate a reference level on the basis of the first, second, or fourth methods and the third method is not applicable or an attempt to determine a reference level in consultation with a Market Participant has not been successful, the ISO shall determine a reference level on the basis of:

      i) the ISO's estimated costs of an Electric Facility, taking into account available operating costs data, appropriate input from the Market Participant, and the best information available to the ISO; or

      ii) an appropriate average of competitive bids of one or more similar Electric Facilities.

c) The reference levels ($/MWh bid price) for the different bid segments of each resource (or import bid curve of a Scheduling Coordinator at a Scheduling Point) will be made monotonically non-decreasing by the ISO by proceeding from the lowest MW bid segment moving forward. For each bid segment the reference level of each bid segment shall be the higher of the reference level of the preceding bid segment or the reference level determined according to paragraph (b) above.

5.11.3 Alternatives Considered

An alternative considered for determining the Reference Levels was to use cost-based proxy bids for thermal generators, since investigation of the real-time market revealed that even after the implementation of the June 19 Order the real-time market is not competitive during many hours and successful bids in such a market are not a good proxy for competitive reference bid prices. This alternative was rejected, however, because it would lead to differential treatment of bidders for whom there are no cost-based proxy bids (i.e., hydro, imports, etc.).

Several alternatives were considered for the level of the AMP thresholds, including the following:

Bid above Reference Level = Min (200% increase from proxy, $100/MWh)

Price Impact = $100/MWh

This alternative was not recommended because the threshold values were deemed to be too large to provide effective market power mitigation.

The ISO considered whether or not this mitigation provision should apply to import bids. Reference levels can be established for imports based on the lower of the mean or the median of an importer's accepted bids over the previous 90 days for similar hours or load levels (similar to the way NYISO established reference levels for resources potentially subject to AMP, and as stated above). Because there are no mitigation provisions to force imports to offer energy into the ISO's energy markets (except when an import is serving as ACAP in the future), as there is with an ACAP or must-offer resource within the ISO control area, the ISO was concerned that an attempt to mitigate economic withholding may simply cause importers to physically withhold from the ISO market. Ultimately the ISO decided to subject all bidders to AMP because the existence of different mitigation rules for different parties invites gaming. In particular, exempting imports from AMP would create an incentive for internal resources to launder their MW and try to sell into the ISO markets as importers.

5.11.4 Comparision with Other ISOs

The only other ISO that has this type of market power mitigation tool is the NY ISO. As discussed above, economic thresholds for energy bids in the NY ISO are set with respect to a resource specific reference level, which is based on the resource's historical competitive bids during similar hours and load levels and adjusted for fuel prices. The bid threshold used by the NY ISO is an increase of 300% from the reference level or $100/MWh, whichever is lower. Similarly, the NY ISO also uses a fairly generous threshold to determine whether the bids had a "material price effect." For example, the energy market impact threshold used by the NY ISO is whether the bidding behavior resulted in an increase of 200% or $100/MWh, whichever is lower, in the hourly day-ahead or real-time energy Location Based Marginal Price (LBMP) at any location.

The CAISO does not feel the thresholds developed by the NY ISO are appropriate for the California market. The NY ISO's fairly generous bid and market impact thresholds may be appropriate for markets that are workably competitive most of the time, but the ISO feels these thresholds are too large to provide effective mitigation in the California market, which tends to be significantly less workably competitive.

5.12 12-Month Market Competition Index and Pre-authorized Mitigation Provisions

5.12.1 Introduction

The fundamental objective underlying electricity market restructuring and implicit in all FERC Orders regarding ISOs and RTOs is that they will promote competition and provide for an efficient power market in order to bring cost savings to consumers over the regulated structure. These objectives have not been measured, however, and indeed may not be achievable if there are structural problems in the market and significant abuse of market power. The ISO believes it is imperative that FERC clearly define market power and commit to a tangible standard for just and reasonable rates in those ISOs that have market based rate authority. Although the ISO market redesign stresses structural and design changes to promote competitive markets, an enforceable just and reasonable rate standard is the best ultimate protection for consumers. This enforceable standard will protect the market during its transition to the new structure and while adequate supply infrastructure and demand response capability are being developed. It is also necessary after the transition to protect the markets against any unexpected problems in order to ensure just and reasonable rates are maintained as stated in the Federal Power Act.

The ISO proposes an objective and explicit standard by which just and reasonable rates can be measured and tracked over time. The proposed standard uses a 12-month rolling price-cost markup index that compares actual average market cost to a competitive baseline average cost. The competitive baseline would be based on an explicit and transparent methodology that calculates the marginal cost of the highest cost unit available to serve system load each hour. If the 12-month rolling average markup is above $5/MWh, the market results should be declared unjust and unreasonable. Having an objective criterion is critical to allow all parties to know when mitigation will be triggered. Thus it can be a prospective standard in the sense that consumers will know that the extent of their exposure to uncompetitive conditions is limited. After it is triggered, the liability will clearly be set for refunds in future periods until FERC makes a finding that rates are just and reasonable. Suppliers will know the threshold, and will be able to self-regulate their behavior in order to preclude intervention, and the FERC and the ISO or RTO will have an objective standard to know when to step in.

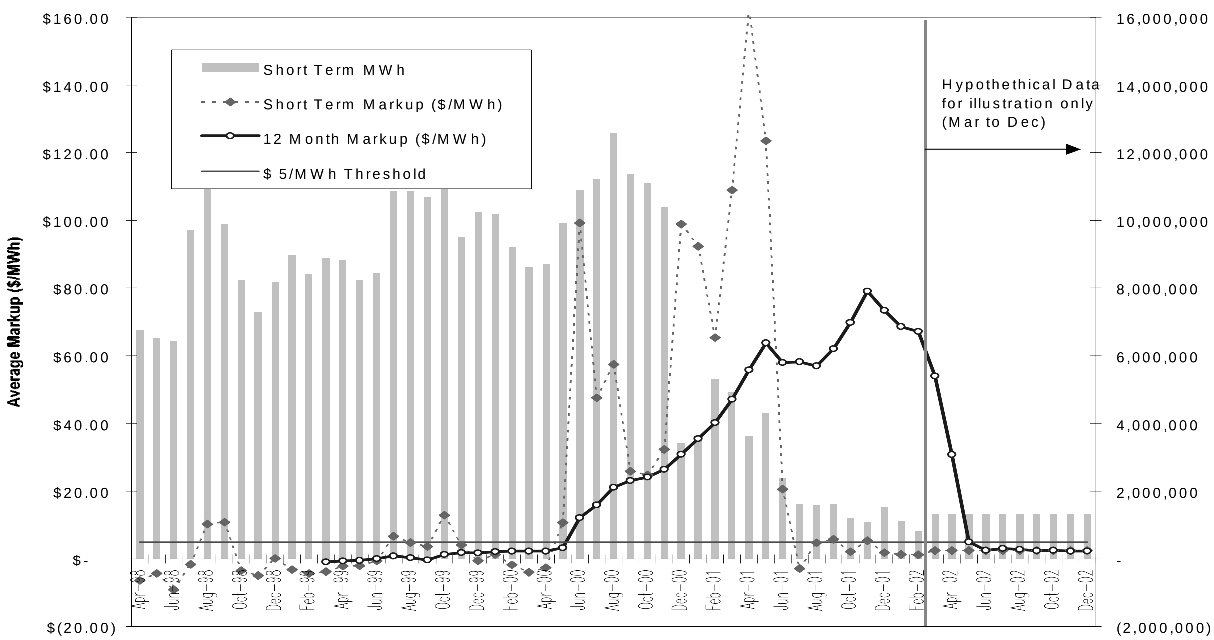
Once the market is declared uncompetitive after the 12-month rolling markup index exceeds $5/MWh threshold, the ISO would have the pre-authorized ability to reinstate FERC's west-wide mitigation and to apply cost-based proxy bid mitigation in all hours for 6 months, or until FERC and the ISO develop more permanent solutions, or until the market is found to be competitive.

This measure is very different than the type of market power mitigation provided by a damage control bid cap. A damage control bid cap will be in effect regardless of overall competitiveness of the market and as such, provides a constant backstop to guard against very large price spikes. The 12-Month Market Competitiveness Index with pre-authorized additional mitigation provisions provides a higher level of protection against sustained market power. These additional mitigation measures will not be invoked if there are occasional price spikes when the overall market is competitive. However, if conditions result in sustained market power problems with significant impact to the consumer, then the pre-authorized measures will be enacted to ensure just and reasonable market outcomes. This index properly considers the duration and magnitude of market impact during a moving 12 month period. A moderate markup slightly above $5/MWh for every month in a 12-month period will trigger mitigation, as will an extreme sustained markup of $30/MWh for a two-month period.

Some have expressed doubt whether a 12-month rolling average would work in the first month. The following example shows how it will be applied and indeed could work in the first month of operation. As an example, suppose that in the first month after lifting the FERC June 19 Order, prices in California skyrocket and average $90/MWh when the competitive baseline after considering gas prices was $30/MWh. In this case the 12 month trigger would kick in because the price represents a $60/MWh price mark-up in one month. Therefore, even if all previous months were exactly at the competitive level, the index would be $5/MWh on a 12-month rolling average basis. Thus it is possible to trigger the index with only one month of excessive market power abuse. Such a threshold will reduce uncertainty for investors, since they will know in advance when, how and what mitigation will be invoked.

The following chart illustrates the 12-month rolling index using a $5/MWh threshold. It is applied to the California market since start-up. Monthly price-cost mark-ups are shown along with a cumulative 12 month average of these mark-ups. As shown below, such a standard would have alerted all parties (consumers, regulators, suppliers) that markets had become uncompetitive in early summer 2000.

FIGURE 1. 12-month Price-cost Markup Index



In the above figure, prices and costs are based on the ISO real time and PX day-ahead and day-of markets from April 1998 to November 2000. Since December 2000, the ISO real time purchases and CERS DA/HA purchases (Short Term Energy) are used. Data for 2002 are hypothetical values; i.e., they are based on the average price-cost markups for the second half of 2001. This assumption was used to simply illustrate that if market prices and costs continue the current trend, the 12-month index will fall below the $5/MWh threshold in June 2002.

5.12.2 ISO Proposal

The ISO proposes to establish a $5/MWh threshold on the 12-month price-cost markup index.

Once the threshold is exceeded the market should be declared uncompetitive and pre-authorized mitigation should be imposed for 6 months, or until FERC and ISO develop more permanent solutions, or until the market is found to be restored to competitive conditions.

The pre-authorized mitigation will be prospective, in the sense that refund obligation and enactment of mitigation occurs after the threshold is hit. At that time, there would be a reinstatement of FERC's west-wide mitigation with the further requirement to provide proxy bid mitigation *in all hours*. This is how the PJM market was run during its first year of operation. Recall that FERC's June 19, 2001 Order provided different types of mitigation depending on whether or not the ISO declared a system emergency. During system emergencies, bids from in-state thermal units were set equal to their proxy bids and the ISO's real-time MCP was set equal to the highest cost proxy bid dispatched. During non-system emergencies, bids are market based and subject only to the west-wide price limit. The bidding requirement would apply to all in-state suppliers and out-of-state ACAP resources.

When west-wide mitigation is triggered by this mechanism, for bids submitted above the prevailing (soft) cap, and called upon by the ISO, the bidder would be paid the MCP, and would have to submit cost justification for payments above the soft cap. This is a change from the way payments for bids above soft cap were made under the June 19 order; under that order the bidders would be paid as bid (above soft cap) subject to refund if not cost justified. Here they will get paid the amount above the soft cap only after cost justification.

5.12.3 Alternatives Considered

The ISO originally proposed setting the threshold at 10% rather than a fixed dollar amount, but subsequently the ISO Market Surveillance Committee (MSC) suggested that the ISO consider a $5/MWh mark-up above competitive levels rather than a percentage mark-up. After reviewing the benefits of this recommendation the ISO determined that using a percentage mark-up may have the unintended effects of discouraging cost reduction and efficiency improvement. The ISO believes that the alternative $5/MWh mark-up has the benefit of providing a performance based rate incentive.

The performance based impact can be seen with the following examples. If suppliers are able to reduce the operating cost of the marginal unit due to efficiency improvement by 20%, the allowable above competitive level profit margin will be reduced by 2% (10% of 20%). This may discourage suppliers from making cost improvements. However, with a fixed $5 margin, any improvements could be kept by suppliers and passed on as lower overall costs to consumers through a lowering of competitive baseline cost of production. Conversely, with a 10% margin as a trigger, if electricity prices rise to $70, then the allowable mark-up would rise to $7. This may provide an incentive to suppliers to increase costs, thereby increasing the mark-up they earn.

Alternative options considered for pre-authorized mitigation include:

A. Revoking market-based rate authority for all FERC jurisdictional sellers in the ISO's market.

B. Apply cost based bidding restrictions only on those market participants that are determined to be able to exercise market power. An objective criterion such as the FERC proposed Supply Margin Assessment would be used to exempt certain suppliers from cost based bidding. In FERC's proposed market based rate standard, it suggested a supply margin assessment test. In the ISO comments, we have recommended some modifications and an alternative but similar screen based on the Residual Supply Index.[73] Using a test that the RSI be greater than 110% for 95% of the time gives more flexibility in assessing how pivotal specific suppliers are likely to be in setting market prices. It will identify whether a supplier possesses too much market power looking at all hours and not just the peak hour. This will allow most small suppliers to be exempt from the mitigation; a healthy competitive fringe will keep the market running and help to restore competitiveness in the future.

5.12.4 Comparision with Other ISOs

No other ISO has this market power mitigation element. However, the ISO believes that this should be a standard element in all ISOs that have market based rate authority. FERC should have a standard to clearly define market power and commit to a tangible standard for just and reasonable rates in those ISOs that have market based rate authority..

[73] A Residual Supply Index is equal to total market supply less the supply of the largest single supplier divided by total market demand. An RSI value less than 1 indicates the largest single supplier is pivotal in the market in the sense that total market demand cannot be met absent its supply.

5.13 Penalties for Excessive Uninstructed Deviations

5.13.1 Introduction

There are several varieties of uninstructed deviations that are covered by this proposal: (1) declining an ISO dispatch instruction; (2) accepting an ISO dispatch instruction but deviating from it by more than a pre-defined tolerance; (3) deviating from a final hour ahead schedule without being so instructed by the ISO. In addition, uninstructed deviations may be positive (i.e., generating above the instructed or scheduled level) or negative (generating below the instructed or scheduled level). All of these have a detrimental impact on reliable operation because they reduce operators' ability to predict the state of the system over the coming operating intervals and to be confident that their dispatch instructions will be effective in maintaining system balance.

Declining real-time dispatch instructions is a serious form of physical withholding. There is currently no mitigation against this type of behavior; although, the ISO tariff states that all real-time bids not withdrawn 45 minutes before the operating hour are binding. The ISO proposes to treat declined instructions as accepted instructions that are not delivered unless the resource in question undergoes a forced outage and the SC so notifies the ISO in time (within 30 minutes from the occurrence of the forced outage).

Uninstructed positive deviations, which can result in excess and unneeded energy, create operational problems that impact reliability, efficiency and market prices. FERC has recognized that strong rate disincentives are needed to induce generators to be vigilant in avoiding over-generation.[74] The ISO proposes not to pay generators for over-generating.

5.13.2 ISO Proposal

The proposed penalties for positive uninstructed deviations will be the quantity of Uninstructed Imbalance Energy in excess of the tolerance band multiplied by a price that initially will be equal to 100% of the corresponding BEEP Interval Ex Post price. The net effect of the uninstructed deviation penalty and the settlement for positive uninstructed deviations beyond the tolerance band will be that the supplier will not be paid for any such Energy. This is appropriate because market participants should not be required to pay for Energy and services the ISO has not requested and does not need.

The penalty for negative uninstructed deviations will equal the amount of Uninstructed Imbalance Energy beyond the tolerance band multiplied by a price that will be set initially equal to 50 percent of the corresponding BEEP Interval Ex Post price. Thus, the net effect of the uninstructed deviation penalties and uninstructed Imbalance Energy settlement will be that this energy will be charged at 150 percent of the corresponding BEEP Interval Ex Post price. The ISO may increase the 50 percent penalty for negative uninstructed deviations if it reasonably determines that such penalty is not effective in improving generator performance.

The ISO proposes a tolerance band for uninstructed deviations before applying the penalty. The proposed tolerance band is the greater of 5 MW or 3 percent of the maximum operating limit of the resource[75] (i.e., Pmax).

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[74] See Central Hudson Gas & Electric Corp. et al., 86 FERC ¶61,062 (1999).

[75] "Resource" in this instance may be defined as the aggregated units, net expected generation for MSS, delivered Regulation range or scheduled load for PLA.

The ISO proposes to continue to issue unit-specific Dispatch instructions and to continue to settle on a unit-specific basis. However, Scheduling Coordinators are permitted to aggregate generators interconnected at a single ISO grid bus point for the purpose of determining the Uninstructed Deviation Penalty, thus effectively gaining the ability to net deviations from units located at a single point. The ISO also will allow for the net determination of penalties for other aggregations of generating units, as approved by the ISO on a case-specific basis.[76] Thus, the ISO's proposal will allow suppliers the flexibility to deviate from their instructed operating point by a reasonable amount without incurring any penalties. Under these circumstances, the ISO's tolerance band is narrowly tailored to serve its purpose, while permitting a reasonable amount of operational flexibility. This latitude of compliance flexibility is sufficient to take into account unintentional deviations that occur as a result of unit operations while being sufficiently stringent to provide incentives to Scheduling Coordinators to maintain expected unit output.

In addition to the flexibility provided to generating units, the instant proposed modifications will allow Metered Sub-System and self-serving Load Market Participants the ability to load-follow, with Uninstructed Deviation Penalties only applying to the net ISO-expected Energy deliveries. Finally, the ISO proposes that entities with limited control over their output, such as intermittent resources and units providing regulation, be exempted from the uninstructed deviation penalty provision.

While the uninstructed deviation penalties described above should help to mitigate physical withholding associated with failing to follow dispatch instructions or schedules, it does not mitigate physical withholding associated with falsely declaring a unit forced out of service. The ACAP obligation is intended to deal with this type of physical withholding (see Section 5.1).

5.13.3 Alternatives Considered

The ISO initially considered using a tolerance band of 3 MW or 3 percent of the instructed operating level. The ISO based this initial recommendation on empirical historical deviations, but many stakeholders felt it to be too restrictive and, given the penalty provision for positive deviations above the tolerance band, would encourage risk-adverse suppliers to bias generation downward. The ISO notes, however, that in Order No. 888-A, FERC stated that:

> [a] generator should be able to deliver its scheduled hourly energy with precision. If we were to allow a generator to deviate from its schedule by 6.5% without penalty, as long as it returned the energy in kind at another time, this would discourage good operating practice. Order No. 888-A, FERC Statutes and Regulations [Regulations Preambles 1996-2000] ¶31,048 at 30,230 (1997)

[76] The ISO will develop a process to allow Market Participants to propose aggregations of generating units that are not at individual transmission bus points. Market Participants proposing unit aggregations will be required to demonstrate that the units aggregated are interchangable, function as a single entity, and will not affect grid reliability.

5.13.4 Comparision with Other ISOs

The ISO is not alone in developing measures to confront the problem of uninstructed deviations in real-time markets. Other Independent System Operators have a tolerance band for uninstructed deviations, ranging from ±1.5% on a net Qualified Scheduling Entity (QSE) basis for ERCOT to NYISO's ±3% on an individual resource basis. As summarized in Table 2 below, the ISO's proposed modifications regarding uninstructed deviations is fully consistent with other Independent System Operator practices and policies and with FERC's decisions addressing this matter.

Table Uninstructed Generation Policies Among ISOs

	Dead-band for Energy	Penalty within Dead-band	Over-generation Charges	Under-generation Charges	Notes
Proposed CAISO	Greater of 5 MW or +/- 3% of expected generation from MSS: greater of 5 MW or +/- 3% of bus generation or Unit Pmax, as applicable	N/A	No Pay for deviations above dead-band	MCP + 50% of interval MCP for deviations below dead-band	SCs may nominate for non-bus-level aggregation of units
ERCOT	±1.5% of QSE Schedules + instructions ±5.0 MW of expected interval generation	N/A	Graduated up to 100%, depending on system conditions	Graduated up to 100%, depending on system conditions	Dead-band may be reduced to ±1%, ±3% day ahead if ERCOT sees that "price chasing" exists.
PJM	No Dead-band	N/A	N/A for network service	N/A for network service	Penalty for schedules point-to-point MWh deviations, ±1.5% (±2 MW) band. Also, resources deviating beyond 10% of the instructed ("economic") base point are not eligible to set the price (LMP).
ISO – NE	(Under-generation only) 2.5% of claimed capacity or any deviation > 10 MW Also must be > 1 MW	N/A	Sanctions	Forfeit of all TMSR, TMNSR and TMOR payments for deviation period	Failure to provide services in real-time: Admin. Penalty = $1000/event; + Formula penalty = 50% of ECP
NYISO	Lesser of ±3% of unit upper operating limit or three times unit response rate	N/A Paid / Charged LBMP	100% (No payment for gen above dead-band. No charge during reserve deficiencies)	MCP_{reg} x under-generated MW	NYISO reserves the right to change dead-band as needed. Units that are off-dispatch can chase the real time price between their hour-ahead schedule and intersection of real-time MCP with their bid curve (with a 3% tolerance band).

The ISO notes that PJM has the lowest additional charges to discourage uninstructed deviations and, for network service customers, there are no additional charges beyond the replacement cost of energy as is determined by the locational market-clearing price. However, all of the other Independent System Operators (*e.g.,* ERCOT, ISO-NE, and NYISO) assess some additional charges to generators undertaking uninstructed deviations. ERCOT measures deviations on a net Qualified Scheduling Entity (QSE) basis (which is similar to a Scheduling Coordinator at the ISO). ISO-NE and NYISO assess the uninstructed deviation charges on a resource specific basis. ERCOT attempts only to assess deviation charges when uninstructed deviations caused or contributed to problematic system conditions by looking at the aggregate deviation from schedule on the resources providing regulation. NYISO has adopted a similar process by relaxing positive deviation charges when it has a system reserve deficiency.

6 Applicability of Design to Governmental Entities

6.1 Proposal for Governmental Entities

Since start-up the ISO Tariff has included the concept of a Metered Subsystem ("MSS"). A MSS is a subsystem within the ISO Control Area that has metering and telemetry at its boundaries and internal generation that serves internal load. In the March 2000 Access Charge filing ("Amendment 27"), the ISO expanded on that concept and included additional specifics as Section 3.3 of the ISO Tariff. Now, with a few years of experience and some pilot programs completed, the ISO is making a renewed effort to develop a refined MSS proposal, to address concerns raised regarding the integration of Governmental Entities ("GE") into ISO operations, as expressed in the recent Federal Energy Regulatory Commission ("FERC") audit.[77] The refined MSS proposal is also intended to address the circumstances where a GE's existing Interconnection Agreement ("IA") or other umbrella Existing Contract with the relevant transmission owner terminates such that the GE is necessarily compelled to establish a new relationship with the ISO.[78]

The fundamental characteristics of a GE that would operate a MSS are that it:

1. has its Load in a geographically contiguous Service Area, subsumed within the ISO Control Area;
2. has been operating for a number of years prior to the ISO Operations Date as vertically integrated utility with Load serving responsibility;
3. has Generation, either owned or contracted;
4. may own transmission or have an Entitlement to transmission; and
5. is not subject to regulation by the California Public Utilities Commission ("CPUC") or FERC.

The MSS will be encompassed by ISO certified revenue quality meters at each interface point with the ISO Controlled Grid and any other point of the interconnected electric grid in the ISO Control Area.[79] The MSS will have ISO certified revenue quality meters on all Generating Units

77 Governmental Entities may include municipal utilities, state agencies, water districts, irrigation districts and federal agencies.

78 The IAs for Northern California Power Agency and Silicon Valley Power are currently scheduled to terminate on August 31, 2002. The IAs for other GEs are currently scheduled to terminate at the end of 2002.

79 For example, some GEs interconnect to the Western Area Power Administration grid within the ISO Control Area and not directly to the ISO Controlled Grid.

or if aggregated into a System Unit, each generating facility, and Participating Loads which are operated in accordance with the ISO Tariff and an agreement with the ISO.

GEs are different than other Market Participants because they are utilities that have retained the obligation to serve the consumers in their Service Areas and are regulated by a Local Regulatory Authority, not the CPUC or FERC. Their objective is to serve their End-Use Customers and to do so, they have sufficient resources, either owned or contracted, to meet their own Load and Ancillary Services requirements. Additionally, the majority of the GEs have financed their projects (transmission, generation and distribution) using tax-exempt financing. An Internal Revenue Service ("IRS") regulation requires that projects financed through tax-exempt financing limit the amount of private use of that project to 10%. The reasoning is that the project was financed for the benefit of the citizens in the Service Area of the GE and not for profit. Since the IRS has not issued permanent regulations regarding this matter, and specifically operational control of transmission, a number of GEs have not participated in the market and are wary of the ramifications associated with participation because of a fear of losing tax-exempt status for their projects.

Moreover, most GEs have Existing Contracts that have not yet terminated which require special treatment including limitations on the use of transmission and special scheduling timelines. The MSS proposal as currently framed would include the following characteristics:

Operations: The GE will be responsible for the supply of Energy and Ancillary Services required to reliably provide electric service to its Loads, including following Load in real-time. The GE may participate in the market, using the same market rules as other Market Participants, or self-provide Energy and Ancillary Services. Scheduling will be done on a gross basis for Generation, imports, exports and Loads on the ISO's timelines, with exceptions as needed for those Existing Contracts that have not been converted to the ISO's Firm Transmission Rights ("FTRs").

Load Shedding: The ISO will revise the Load shedding procedure and ISO Tariff language to recognize the difference between ordinary System Emergencies and System Emergencies due to identifiable resource deficiency. In some cases, one or more Scheduling Coordinators may not acquire sufficient resources to meet their Loads; in that case the Utility Distribution Company ("UDC") or MSS that has Scheduling Coordinators that are deficient will be required to shed Load.[80] In the case of a resource deficient System Emergency that is known in advance of real-time, UDCs and MSSs that have sufficient resources, including Ancillary Services, will not be required to shed Load.

Metering and Telemetry: ISO certified revenue quality metering and telemetry is required at all generating facilities and interconnection points based on the ISO Tariff standards.

UDC Obligations: GEs that operate MSSs will have the same general requirements as UDCs, except, if they are not participating with their Generating Units in the ISO's markets, their Generation will only be required to be available for ISO Dispatch in System Emergencies that are not due to resource insufficiency.

Settlements: Settlements will be in accordance with the ISO Tariff except as provided in the MSS agreement, including recognition that GEs operating MSSs should not be subject to certain ISO charges based on principles of cost-causation.

[80] UDC refers to the operator of an electric distribution system that has entered into a UDC Operating Agreement with the ISO, which may be regulated by the CPUC or another regulatory authority. Thus UDC may encompass GEs that more fully integrate with the ISO's systems, as well as the CPUC-regulated investor-owned utilities (IOUs).

Interconnections: The GE will be responsible for maintaining established operating parameters including the control of real and reactive power flow within stated standards at all interconnection points.

Information Sharing: The GE will coordinate with the ISO and provide the ISO information regarding expansion, retirement and modification of facilities; maintenance and outage schedules, and reliability information on system status; and both parties will share annual reports and reviews.

Generating Units: Generating Units located within the GE's MSS may be aggregated into System Units with the approval of the ISO. The GE will retain control over its Generating Units unless it sells into the ISO's markets. In a System Emergency, other than a System Emergency for resource deficiencies, the GE will respond to the ISO's Dispatch instructions.

Relationship to ISO Tariff: The MSS agreement will specify exceptions to the ISO Tariff.

Reliability Issues: The GE will be required to reliably maintain its MSS, including providing or procuring black start and voltage support. GE will abide by the WSCC Reliability Criteria Agreement and WSCC Reliability Management System (RMS) program.

6.2 The Issues and Their Importance

The objective of the MSS concept and the current MSS proposal is to develop a workable market participation model for GEs, including but not limited to scheduling, operations and settlement. The proposal is intended to address the problems perceived with the ISO's structure as it affects a GE's obligation to serve the customers in its Service Area and GE tax-exempt financing issues. The proposal includes a provision that the GE will affirmatively accept the obligation to serve its Load and the option for the GE to follow such Load with minimal, if any, economic or operational impacts on the ISO. For the ISO, it must continue to honor Existing Contracts, allocate costs based on cost causation principles and minimize cost-shifting among Market Participants. These steps hopefully will encourage GEs to more fully integrate with the ISO.

The ISO is the Control Area operator of both the ISO Controlled Grid and non-ISO Controlled Grid facilities. This dual role, and the fact that the ISO does not generally have access to detailed information regarding the status and scheduling of non-grid facilities, has hampered the ISO's functioning in the past. Thus these issues are important because of the operational difficulties created by two classes of participants and the "holes" it makes in the Control Area. By recognizing the differences and reaching a resolution to such differences between GEs and other Market Participants through the MSS proposal, the originally anticipated efficiencies of a single ISO Control Area may be achieved.

6.3 Comprehensive Design and Metered Subsystems

For each of the elements of the ISO's proposed comprehensive market design addressed below, it should be noted that a GE has the option of being treated like any other Market Participant. However, to the extent that the GE wants special treatment in recognition of its special features and functions, the ISO is proposing the MSS concept. For each of the elements below, the special treatment that would be afforded to each GE operating a MSS is discussed, along with the consequences of the treatment. Additionally, a GE may elect to accept the special treatment proposed for one element and not another, where it is logically consistent and practically feasible to do so. The ISO will attempt to include that flexibility in the MSS proposal.

6.3.1 ACAP Requirement

The GE will have the same requirements as other Load Serving Entities ("LSEs") to show the ISO it has met the ACAP requirement. Additionally, the GE that operates a MSS must schedule 100% of the forecasted Load and Ancillary Services in the Day-Ahead Market. The GE that operates a MSS will not be required to make its resources available for commitment by the ISO under ACAP or RUC; however, absent sufficient resources, the GE that operates a MSS will be required to shed its own Load to meet any deficiencies.

6.3.2 Forward Congestion Management

Any congestion internal to the MSS will be the responsibility of the GE to manage, including cost responsibility, and will not effect the ISO Controlled Grid. If the GE has an Existing Contract right on the ISO Controlled Grid, then such use of the ISO Controlled Grid will be exempt from congestion charges. Conversion of Existing Contract rights to FTRs, if feasible, may mitigate some of the phantom congestion that currently exists on the ISO Controlled Grid.

In the event not all ETCs are converted to FTRs, ETC transmission capacity not scheduled by ETC holders in the day ahead market could be made available to other grid users through a Recallable Transmission Service (RTS), in which the ISO auctions a portion of the unused ETC capacity subject to recall if the rights holder exercises its contract rights to schedule at a later time. (RTS was described in the January 2001 Congestion Management Reform proposal, which is available on the ISO web site at http://www.caiso.com/clientserv/congestionreform.html).

6.3.3 Forward Energy Market

The GE will schedule gross Generation, imports, exports and Load, and Ancillary Services to meet its Load based on the ISO Tariff requirements through self-provision or purchases from the ISO's markets. Additionally, the GE may sell into the forward and the Supplemental Energy market. To the extent the GE participates in any ISO markets, all market rules established in the ISO Tariff apply.

6.3.4 Firm Transmission Rights

The GE will have the ability to purchase FTRs like any other Market Participant. For Existing Contracts, the ISO would prefer to convert Existing Contract rights into FTRs, with those FTRs allocated to the GE. Whether or not ETC holders choose to convert their rights, each ETC must be characterized by a pattern of injections and loads based on the historic use of the ETC rights by the contract holder. As described in Section 5.3, if the ETC holder does not convert the ETC rights to FTRs, this characterization will be needed to enable the ISO to determine how much of the capacity of the ISO grid must be reserved to accommodate all non-converted ETCs. If the ETC holder does convert to FTRs, this characterization will be needed to enable the ISO to provide the appropriate set of point-to-point FTRs to the ETC holder.

The needed characterization of ETC scheduling rights and transmission capacity, including how such capacity changes based on the available transfer capability of the path, will be very difficult because each ETC may have different rights. Therefore, to honor ETCs as required by FERC, the ISO may not be able to convert every ETC to a perfectly similar FTR.

6.3.5 Ancillary Service Market

The GE may self-provide Ancillary Services, or sell or buy Ancillary Services to or from the ISO. To the extent the GE participates in any ISO markets, all market rules established in the ISO Tariff apply.

6.3.6 Residual Unit Commitment

The GE that operates a MSS has the option to be responsible to follow its own Load, and resources will not be committed in the RUC process for the MSS if it does so. In the Day-Ahead Schedule that is provided by a GE that operates a MSS, the GE must schedule 100% of its Load and applicable Ancillary Services with associated Energy to demonstrate to the ISO that the GE has sufficient resources. If the GE that operates a MSS does not demonstrate sufficient resources, then, like other Market Participants that under-schedule, the ISO will commit resources in the RUC process and the GE will be charged the RUC costs.

6.3.7 Hour Ahead and Real-time Markets

The GE will adjust its Schedules in the Hour-Ahead Market like other Market Participants, and follow its Load in real time. In order to recognize and facilitate Load following by a GE, the GE choosing that option will be accountable to accurately schedule its resources and Load within 3% of the lesser of its metered Demand and exports in real-time or its Hour-Ahead Schedules. Any additional deviations will be charged the uninstructed deviation penalty. The ISO will be monitoring the boundary meters to ensure that the MSS is not leaning on the ISO system in real-time.

6.3.8 Real-time Economic Dispatch using Full Network Model

The GE will be responsible for dispatching its own resources to meet its Load, the ISO will not dispatch such resources. If the GE participates in the ISO's markets, then the ISO will dispatch the GE's units based on the acceptance by the ISO of a bid. Any declined instructions will then be subject to penalties for uninstructed deviations.

6.3.9 Demand Bidding

If the GE is using Demand programs to meet its ACAP requirement, then the GE may not bid these programs into the ISO's markets. If the GE has additional Demand programs, or programs in excess of its own requirements, then the GE may bid them into the market.

7 Compliance Monitoring Requirements

7.1 Introduction

7.1.1 Need for Compliance Monitoring

Compliance Monitoring is an essential element of any functioning market. The fundamental purpose of Compliance Monitoring is to verify that the products and services procured by the ISO on behalf of market participants in a manner consistent with the ISO tariff, any applicable agreements and/or standards and good utility practice. In a bilateral market, the purchasers directly receive the products and services provided by suppliers and can readily verify that they have received the product or service purchased. However, when the ISO procures products and services on behalf of buyers, the buyers may not be able to directly verify whether the product or service was received or even what suppliers were obligated to provide the product or service. As a result, it becomes a fundamental responsibility of the ISO to verify that the suppliers have provided the products and services procured on behalf of market participants. To the extent that one or more supplier may not have fulfilled its obligation, the ISO must take appropriate steps to remedy the situation in as fair and unbiased manner as possible.

A fully functioning Compliance Monitoring program provides confidence to all market participants for fair and equitable treatment in procurement and delivery of the products and services procured through the market.

7.1.2 Explanation of Compliance Monitoring

Compliance Monitoring may take on a variety of forms, from answering the traditional question, "Did Market Participant A fulfill their obligations?" (an after the fact evaluation) to performing validation of bids and offers before a market is run. An essential element of Compliance Monitoring is quality data on which compliance decisions are made. Therefore it is necessary to perform audits on such things as the processes in place to validate and submit accurate and correct SQMD or generator outages and derates.

7.2 Compliance Monitoring Requirements for the Comprehensive Design Elements

7.2.1 ACAP Procurement Validation

The ISO will establish month ahead, day ahead and possibly annual milestones at which time the ISO will compare the ACAP procured by each LSE with their expected ACAP obligation. To the extent that an LSE has not fulfilled the ISO forecast ACAP obligation, they will be notified of expected deficiency penalties.

7.2.2 ACAP Resource Availability

ACAP resources are required to offer available generating capacity into the RUC process and into the real-time Energy market. Resources that withhold available capacity from the RUC process and/or the real-time Energy market will have default offers inserted on their behalf by the ISO (see section 7.2.4 below). Resources that are unavailable due to a forced outage, or if responding to a Dispatch instruction would result in loss of QF status, loss of an environmental permit or criminal penalties, must report their availability status to the ISO. Unless the ISO is notified that capacity is unavailable, the ISO has no option except to assume that it is available.

ACAP resources that are unavailable for all or part of a month in which they have been designated to provide ACAP supply to an LSE may be subject to deficiency penalties, replacement Energy, a derated eligibility to supply ACAP in future months or other such sanctions as may be designed into the ACAP requirements.

ACAP resources that have part or all of their capacity selected in the RUC process must hold that capacity available for the ISO to Dispatch in real time. To the extent that such a resource self schedules, is derated or becomes otherwise unavailable, the ISO will rescind the start-up and minimum load payments, if applicable. Export schedules that are linked to Non-ACAP resources will be accepted, but ACAP resources will not be permitted to export power from the ISO Control Area.

7.2.3 Must Offer Resource Availability

Non-hydro PGA resources are required to offer available generating capacity into the RUC process and into the real-time Energy market. Resources that withhold available capacity from the RUC process and/or the real-time Energy market will have default offers inserted on their behalf by the ISO (see section X.2.4 below). Resources that are unavailable due to a forced outage, or if responding to a Dispatch instruction would result in loss of QF status, loss of an environmental permit or criminal penalties, must report their availability status to the ISO. Unless the ISO is notified that capacity is unavailable, the ISO has no option except to assume that it is available.

Must-offer resources that have part or all of their capacity selected in the RUC process must hold that capacity available for the ISO to Dispatch in real time. To the extent that such a resource is derated or becomes otherwise unavailable, the ISO will rescind the RUC capacity payments and, if applicable, the start-up and minimum load payments. If a Scheduling Coordinator schedules for export capacity that was committed to the ISO in the RUC process, the ISO will rescind the RUC capacity payments and, if applicable, the start-up and minimum load payments.

7.2.4 Must Offer / ACAP Resource Bidding

Must-offer and ACAP resources are required to offer their available capacity to the ISO in the RUC process and the real-time Energy market. In the RUC process must-offer and ACAP resources are expected to provide three-part bids.[81] In the real-time Energy market, only Energy price curves are to be submitted. If the Scheduling Coordinator fails to submit Energy price curves for capacity that the ISO believes is available, the ISO will insert bids on their behalf. The bids that the ISO inserts on behalf of the Scheduling Coordinator will be based on the incremental heat rate curve and the applicable monthly gas price index. Inserted bids are treated and the Scheduling Coordinator is obligated to perform on Dispatch instructions issued on inserted bids in exactly the same manner as bids submitted by the Scheduling Coordinator.

7.2.5 Excessive Uninstructed Deviations

7.2.5.1 RUC Process Payments

The RUC process identifies generation with available excess capacity and generation that would otherwise be off-line and provides payment for committed capacity, start-up costs and minimum load Energy costs as compensation for a commitment to be on line and available to receive Dispatch instructions in real time. Generators that excessively deviate from their real-time expected operating point are at risk of losing all or part of their committed capacity, start-up and minimum load Energy payments.

[81] The three parts are for start-up costs, minimum load costs and an Energy price curve. The start-up and minimum load are to be bid at cost based on the start-up fuel consumption and the average heat rate at the minimum load operating point of the resource and the applicable monthly gas price index. The Energy price curve is to be bid by the Scheduling Coordinator.

7.2.5.2 Real-Time Energy Deviations

Resources that undertake excessive deviations from their real-time expected operating point will be assess a penalty for that portion of the deviation that is outside of a tolerance band. The penalty for positive uninstructed deviations will be 100% of the deviation Energy times the MCP. The penalty for negative uninstructed deviations will be 50% of the deviation Energy times the MCP. For purposes of calculating the deviation penalties only, Scheduling Coordinators will be allowed to aggregate resources that feed into the same bus within a plant.

Declined dispatch instructions are treated as if the instruction was acknowledged and not delivered, and uninstructed deviation penalties apply, unless the resource has undergone a forced outage and the ISO is notified through established procedures within 30 minutes of the event that the resource is unavailable (or derated).

7.2.5.3 Eligibility to Set Price

Under the ISO's current authority, resources are ineligible to set the Market Clearing Price in intervals in which they do not respond to a Dispatch instruction. If the marginal resource is flagged as ineligible to set the MCP, the MCP will be reduced to the price of the next less expensive resource that is eligible to set the price. An alternative method that may be more compatible with congestion management using the full network model is one in which resources are monitored in real time and those that are within a tolerance band of the expected operating point are labeled as eligible to set the price. This avoids a major disadvantage of relying on the ISO's current authority, specifically the potential to undermine price transparency. When resources are flagged as eligible or ineligible based on meter data read in the days after the operating day, the price will need to be revised whenever the marginal resource dispatched was found to be ineligible to set the price. The major advantage of determining eligibility to set the price under the ISO's current authority is that meter data may be used to determine eligibility rather than relying on telemetered data.

7.2.6 Ancillary Service Certification

All resources that intend to offer to supply Ancillary Services must be certified for the specific services to be offered. Resources will be flagged based on their ability to provide specific Ancillary Services and offers to provide Ancillary Services will be validated against the resource-specific technical constraints for providing the service.

7.2.7 Ancillary Service Availability and Supply

All suppliers must maintain the ancillary service capacity that they have offered to the ISO for its exclusive use. The generator, the Scheduling Coordinator, an LSE, a UDC or any entity other than the ISO may not issue instructions to Dispatch Ancillary Service capacity.

7.2.7.1 Regulation

Generating Units providing Regulation to the ISO must provide sufficient regulating range to meet there Regulation schedule, they must be operating within their range, they must be on control and respond to instructions in a manner consistent with their bid. Failure to meet these fundamental requirements will result in loss of an appropriate portion of their capacity payment.

7.2.7.2 Spinning and Non-Spinning Reserve

Resources providing Spinning and Non-Spinning reserve to the ISO must maintain sufficient available capacity to deliver the scheduled reserves upon ISO Dispatch instruction. Furthermore, failure to accept and fully perform on Dispatch instructions will result in loss of an appropriate portion of the capacity payment. Undertaking uninstructed deviations that encroach upon reserve capacity not only results in loss of the capacity payment, but also in loss of any Energy payment associated with the uninstructed deviation. In the event that the ISO issues an unannounced test for reserve capacity and the resource does not provide some or all of the reserve capacity, the portion of reserve capacity that is not delivered will be deemed to have been unavailable for the entire committed period between the last unannounced test (or Dispatch of reserve capacity, whichever is more recent) and the present test.

7.3 Discussion of Changes from Current Authority

Compliance Monitoring activities related to RUC, ACAP and penalties for excessive uninstructed deviations are newly proposed initiatives that are necessitated by the market design changes in the Comprehensive Design Proposal.

The proposal for Compliance Monitoring with respect to the must-offer obligation is an extension of the existing must-offer obligation that is set to expire on September 30, 2002.

8 Financial Settlements

8.1 Introduction

Several key changes in this market design compared to the existing ISO design, specifically, congestion management, resource adequacy obligations and energy pricing (LMP versus zonal), help to better align cost allocation with cost causation, reduce cost socialization, give the market participants greater ability to predict costs for services they use, and minimize exposure to price volatility through their scheduling practices. This comes at the cost of some complexity in the market design itself, and subsequently in the financial settlement of these markets. The introduction of locational marginal pricing utilizing the full network model alone is significantly more complex than the existing zonal model.

Some aspects of this market redesign effort, while allowing market participants flexibility in scheduling and at the same time assuring that the ISO has the best tools in hand to operate the grid reliably, are intended to encourage that the majority of demand be met in forward markets. As such, the financial settlement is on a cost causation basis and only socializes costs when the benefit is to all users of the grid and ISO services and not for market participants that heavily rely on the ISO real-time energy market. Even with cost-causation as a primary objective of coat allocation, the underlying infrastructure inadequacy in California may initially require more socialization of costs than would be normally associated with a mature market design.

Previous market design did little to place a pricing premium on real-time energy procurement and as a result there was little, if any, incentive for demand to be scheduled in forward markets putting the ISO in a position of often meeting upwards of 15% of demand in real-time. It is widely recognized that leaving this much demand exposed to the real-time market is a recipe for undue price volatility and has shifted the focus of real-time procurement to pricing and price caps rather than the quality of real-time energy.

Another significant element of the previous design that is being corrected in the MD02 effort, is the location and feasibility of demand schedules in the forward markets. While the previous design assumed that market participants would make sure that load was accurately scheduled, the record indicates that this is not the case. Greater emphasis on locational accuracy and feasibility of demand schedules is a feature of the current design with the intent of minimizing the financial impact of inaccurate scheduling practices by a few to those who endeavor to schedule demand accurately. Emphasis on the accuracy of generation scheduling is a cornerstone of the MD02 design that was missing in the initial design of the California market. Explicit pricing of all congestion eliminates the DEC game whereby in the initial design those who caused intra-zonal congestion were rewarded to eliminate it rather than getting charged for causing it. Moreover, in the initial design, decentralized unit commitment was left up to the generation owners to internalize the risks associated with the technical constraints of their resources in their energy bids. Provision of unit commitment service in MD02 permits explicit consideration of resource technical constraints and costs, and allows for feasible scheduling of generation resources.

8.2 Proposed Cost Allocation

The funds collected from Uninstructed Deviation penalties will be used to reduce the amounts recovered from all market participants with metered demand in the order listed below:

1) the penalty fund will first apply to reduce costs associated with procurement of RUC costs greater than the Scheduling Coordinators negative deviations from day ahead schedules.
2) Remaining funds from the penalty will then be used to reduce the portion of Excess Cost for Instructed Energy that is allocated to SCs pro rata based on Metered Demand. (The penalty fund will not lower CT 487 charges assessed to negative deviation.)
3) Any remaining penalty funds, after satisfying the sequential commitments listed above will be treated in accordance with SABP 6.5.2.

8.2.1 ACAP

Rather than continue to dictate that anticipated capacity shortfalls be subject to the ISO procurement of Replacement Reserve through an ISO operated auction, , and in order to assure adequate capacity to cover load forecast error, this fundamental responsibility will be covered by the ACAP obligation. While the ISO will continue to forecast system load for the purpose of assuring the reliable operation of the grid, rather than determine the level of Replacement Reserve to procure, it will commit required ACAP resources through the RUC process. As such, most of the costs associated with ensuring adequate capacity will lie directly with the Scheduling Coordinator representing load. Section 5.1.11 of this report covers the criteria that would apply to a Scheduling Coordinator with less ACAP procured than deemed necessary, and the monthly and/or daily financial penalties that would be charged to ACAP deficient Scheduling Coordinators. The allocation of funds from the ACAP deficiency charge has not yet been determined.

8.2.2 Firm Transmission Rights

Changes to the congestion model will result in more options for defined FTRs in that they will no longer be limited to predetermined contract paths and a limited number of zones, but can be customized to better assure that a Scheduling Coordinator can have financial certainty in transmission use, while enabling the ISO to manage congestion on all transmission paths for reliable operation regardless of relative commercial significance of the paths. The financial model being adopted will require that additional congestion charges be calculated with more specificity than the existing zonal model. While this may require more detail to be introduced in settlement statements and invoices, it will provide greater transparency to the user. While it is nearly impossible to predict what level of congestion will exist with the introduction of the full network model, congestion revenues will continue to be paid to FTR holders and transmission owners. However, there may be liabilities for FTR holders as well that do not exist in the present FTR system. The FTR auction revenues will be allocated to the entities that made transmission capacity available for the auction. Initially, FTRs will be allocated to LSEs on behalf of end use loads. FTRs in excess of those allocated to LSEs will be auctioned by the ISO with revenues distributed to transmission owners. .

8.2.3 Forward Congestion Management

Since the same load flow model is used in the forward markets as real-time and steps are taken to assure feasible schedules in running the congestion model, the price signals derived in the forward congestion market should vary little from those in real-time. This means that more accurate price signals can be developed based on schedules opening the door for reasonable schedule based settlement and a shorter settlement timeline. Furthermore, an accurate load flow model means that as long as load is scheduled accurately, there is less socialization of congestion costs for forward and real-time scheduling errors.

8.2.4 Forward Energy Market

Implementation of a nascent forward energy market, while not inherently complex, will be an addition to the ISO market, settlement of which is certain to increase the volume of information provided to Scheduling Coordinators by the ISO for financial settlement. A forward energy market is certainly one area that can be settled on a timeline more compatible with existing wholesale energy markets since it is not dependent on the collection of meter data. As such this element needs to be considered in the context of a separate statement and invoicing timeline.

Since the forward energy market design under consideration contemplates that it will be run simultaneously with congestion management, nearly all Scheduling Coordinators will be implicated in its settlement. This is a function of including balanced schedules along with unbalanced schedules in the congestion management process.

8.2.5 Ancillary Service Market

The ancillary service markets and settlement will likely remain unchanged with the exception of elimination of the replacement reserve market. While running the ancillary service procurement process simultaneously with the energy market will have an impact on the price paid to sellers of ancillary services, the allocation to demand will remain unchanged at this time. The ISO will continue to allow self provision of ancillary services and validate the feasibility of self provided amounts prior to determining a Scheduling Coordinators ultimate obligation.

8.2.6 Residual Unit Commitment

Residual unit commitment, because it is a procurement process based on a day ahead load forecast and hence is vulnerable to forecast error, is one area of financial settlement that introduces the socialization of costs out of necessity. The need for residual unit commitment derives from the operational need of the ISO to identify adequate resources on a day ahead basis to meet the next day’s expected energy and reserve requirements. Ideally all LSEs will come through the forward markets having met all of their energy requirements and requiring only relatively small amounts of balancing energy that can be allocated directly to load deviations. In practice, however, day ahead final schedules may differ substantially from the next day’s load forecast and the ISO will need the ability to commit resources in the day ahead time frame to assure that reliability requirements can be met in real-time.

Energy consumption associated with RUC will continue to be allocated in the same manner that imbalance energy is allocated to deviations in the current market. That is, load not met by forward scheduled resources will be charged to Scheduling Coordinators based on their reliance on the real-time energy market. From an energy procurement standpoint it does not matter if the energy was dispatched from a supplemental energy bid or from a resource committed in the RUC process. The cost of commitment including start-up and no-load costs for under-scheduling in the forward markets is a different matter. These cost need to be confined, to the extent possible, to the Scheduling Coordinators that fail to schedule their load in the day ahead market.

While it is anticipated that in most cases the ISO will be able to identify the amount that a Scheduling Coordinator failed to schedule in the forward markets, and subsequently allocate unit commitment costs, there will be times when the amounts committed exceed the amounts of under-scheduled load. It is in these instances that the ISO may be required to allocate some costs to all ISO metered demand. As indicated earlier, funds collected from Uninstructed Deviation penalties will be used to reduce the excess unit commitment cost that is allocated to the scheduling coordinators pro rata based on metered demand.

8.2.7 Hour Ahead and Real-time Market

The impact of changes to the Hour Ahead and Real-time markets will be virtually unchanged from a settlements perspective.**]** While the timing of these markets may change, the services procured and the allocation of payments and costs for those services will only change to the extent described elsewhere in this section. There may be a requirement for additional detail in the settlement statement for validation purposes when the effects of the AMP process is applied to bids.

8.2.8 Real-time Economic Dispatch using Full Network Model

The impact to the settlement system comes in the prices derived from the full network model rather than the allocation methodology of those costs from real-time prices. This will certainly require a more granular treatment of deviations to the extent that the level of load aggregation changes from the current levels are in place as anticipated phasing in of LMP pricing.

8.2.9 Demand Bidding and Settlement

For the purposes of simplicity and consistency, the suggested market design treats demand as similarly as possible to generation for the purposes of price responsive instructed dispatch. This will allow for a more automated treatment of demand bids in the settlement process rather than the manual processes that were required under previous demand programs operated by the ISO.

8.2.10 Metered Subsystem Settlement

The elements particular to the settlement of Metered Subsystems are described in detail in other parts of the design document and do not affect the overall design of the settlement system or the fundamentals of settlement. The key element of the MSS proposal from a settlement perspective and significant to a qualified MSS is that some of the charge types that are allocated to metered Demand are charged for the usage of the ISO Controlled Grid and not to control area gross load. This change also affects the definition of load deviation and how deviation based charges are allocated to a MSS.

To the extent that the MSS meets its own load deviation within its metered boundary with resources within that boundary, the effect on the procurement of resources to the rest of the ISO control area is isolated and does not affect the outcome of deviation settlement to non-MSS entities. To the extent that load deviation cannot be met within the metered boundary of the MSS, that portion of the deviation and reliance on ISO procurement will be treated the same as all others relying on the ISO to meet energy and ancillary service requirements.

8.3 Summary of Allocation Issues

Table 1: Day Ahead Market and RUC for 10/01/02 to 03/31/03

#	Description	Options	Pros	Cons	Discussion & Assumptions
1	Allocation of capacity costs incurred in RUC	***ISO Proposal:*** Charge to SC's net actual under-scheduled load deviations only to the extent that the sum total of all SC's net actual under-scheduled load deviations are less than or equal to the total system forecasted under-scheduled load deviation. Charge any remaining cost to SC's pro rata based on Metered Demand. "Net actual under-scheduled load deviation" ,in this instance, will be defined as the difference between the sum of an SC's final DA load schedule(s) and the sum of an SC's metered load(s) and where this difference is negative.(See draft Tarriff 5.12.8 through 5.12.8.3.2)	• Sufficient "cost causation" for those who underschedule but they are not burdened with total costs if ISO over-procured. ▪ Provides incentive to schedule DA.	More complex settlement scheme	Assumes there will be deviation penalties for generators. Thus, allocation is justified for those who under-schedule load. MSS treatment will be same as market. To the extent there is load following present, the MSS will avoid the first tier of the proposed allocation scheme.
		Other Options Considered:			

#	Description	Options	Pros	Cons	Discussion & Assumptions
		a) Charge to under-scheduled load deviation (delta of DA & meter)		Lacks sufficient "cost causation" when procurement is greater than deviation.	
		b) Charge pro-rata to all metered load + exports.	Simple	▪ No "cost causation" ▪ Provides no incentive to schedule in DA.	
2	Intertie energy procured during RUC process is paid the greater of as-bid or market revenue. Dispatched energy considered "pre-dispatched" imbalance energy and paid instructed energy up to MCP. As bid payments above MCP are covered as uplifts.[82]	***ISO Proposal:*** Allocation is to net negative deviation for procurement </= system deviation, for remaining uplift, allocate to metered load + exports.	▪ Sufficient "cost causation" for those who negatively deviate in RT but they are not burdened with total costs if ISO over-procured. ▪ Provides incentive to forward schedule.	▪ More complex settlement scheme	Net negative deviation is determined by the difference between **HA** final schedules and meter. Allocating to net negative deviations is justified since those who lean on the system in real-time benefit from energy dispatch.

[82] The team assumed that any as-bid payments above MCP must be subject to FERC reasonableness justification.

#	Description	Options	Pros	Cons	Discussion & Assumptions
3a	Allocation of startup costs for RUC commitments	***ISO Proposal:*** a) Merge start-up costs with minimum load costs (see 3b) and allocate using same methodology as stated in Strawman Proposal for item 1 above.	Cleaner to settle all RUC commitment costs together. See item 1.	See item 1.	See Proposal for item 1 above.
		Other Options Considered:			
		b) Charge to underscheduled load deviation (delta of DA & meter)	a) Simple b) Provides incentive to forward schedule.		
		c) Charge pro-rata to metered load + exports	Simple	▪ No "cost causation" ▪ Provides no incentive to schedule in DA.	
3b	Allocation of minimum load costs for RUC commitments. Minimum run energy is considered instructed energy.	***ISO Proposal:*** Merge minimum load costs with start-up costs (see 3a) and allocate using same methodology as stated in Strawman Proposal for item 1 above.	▪ Cleaner to settle all RUC commitment costs together ▪ *See item 1.*	See item 1.	See Proposal for item 1 above.
		Other Options Considered:			

#	Description	Options	Pros	Cons	Discussion & Assumptions
		b) Allocate minimum load costs charged pro-rata to metered load + exports		▪ Uplift methodology lacks sufficient "cost causation" ▪ No incentive to forward schedule.	
		c) Allocation is to net negative deviation for procurement </= system deviation, for remaining uplift, allocate to metered load + exports.	▪ Charges those who negatively deviate in RT, thus consume the energy. ▪ Similar methodology as current RT energy uplifts.	▪ More complex settlement scheme ▪ Lacks sufficient cost causation as energy produced is result of lack of DA Scheduling	An SC's net negative deviation for a given interval is the difference between the net HA final schedules and the net meter (i.e., a portfolio deviation).

Table 2: Day Ahead Market (and FTRs) after 03/31/03

	NOTE: Items 4a and 4b below can be combined as one settlement.				
4a	Allocation of startup costs for commitments during energy market	***ISO Proposal:*** a) Allocate to the SCs whose DA scheduled demand is in excess of DA scheduled supply, considering energy trades	Provides "cost causation" for those SCs purchasing from the market.	Lacks "cost causation" for SCs whose where preferred source is not taken due to a transmission constraint.	May need to determine an additional allocation for commitments made for locational constraints.
4b	Allocation of minimum load costs (uplift only) for commitments during energy market	Allocate to the SCs whose DA scheduled demand is in excess of DA scheduled supply, considering energy trades	Provides "cost causation" for those SCs purchasing from the market.	Lacks "cost causation" for SCs whose where preferred source is not taken due to a transmission constraint.	Assumption is the minimum run energy is paid at the LMP and allocated through the energy/congestion market settlement. Allocation defined here is only for minimum load cost uplift
5a	Allocation of startup costs for RUC commitments	Allocate using same methodology in 3a	See above	See above	
5b	Allocation of minimum load costs for RUC commitments. Minimum run energy is considered instructed energy.	Allocate using same methodology in 3b	See above	See above	
6	FTR balancing account has a monthly clearing.	Possible parties to allocate include PTOs, FTR holders, and grid users			

California Independent System Operator

Market Design 2002 Project

Comprehensive Design Proposal

Appendix A

Analysis and Examples Regarding Firm Transmission Rights

April 19, 2002

Appendix on Firm Transmission Rights (FTRs)

1 Discussion of ISO Proposal

1.1 FTR Alternatives Considered

A critical component of any market based congestion management system is the definition of transmission rights. However the specification of transmission rights is complicated by externalities due to loop flows. Since the actual power flows in a transmission grid observe the Kirchhoff's Laws, the power flow paths generally diverge from the intended delivery paths, known as contract paths. Parallel flows, or loop flows, can cause the apparent costs of running generators to diverge from the real costs and make it difficult to determine the available transfer capabilities of the transmission system. This complexity leads to misalignment between the private cost and the social cost in electricity transactions and causes a potentially costly dislocation of resources in the power market.

A market-based solution to this externality problem is to issue a set of well-defined transmission rights that internalize these effects. A market for these rights enables the external effects associated with a transaction to be incorporated into private purchasing and sales decisions. In essence, a transmission right is a property right that allows its holder to access a portion of the transmission capacity. Generally, a property right consists of three components: (1) the right to receive financial benefits derived from use of the capacity, (2) the right to use the capacity, and (3) the right to exclude others from accessing the capacity. Transmission rights can be defined as any combination of these three components. There are three possibilities: The first possibility is based solely on financial benefits, and this is generally known as the *financial-right approac*h. Financial rights—also known as passive rights —provide market traders and other market participants an instrument for constructing financial hedges as part of long-term energy contracts. The second approach combines financial benefits with capacity reservations or scheduling priority and is called the *capacity-reservation approac*h. For most purposes, this approach provides adequate assurance of access to the network. The third approach includes all three components and is known as the *physical-right approac*h.

The definition of transmission rights depends on how transmission capacity is specified and measured. There are two common ways to specify the transfer capacity of the network. One way is to compute the point-to-point transfer capabilities, and the other is to specify the power-flow-carrying capacity for each link of the network. The point-to-point definition is rooted in what has been commonly known as the contract path approach. However, the transfer capability between any two points in a network changes continuously as the pattern of power flows shifts; therefore, it needs to be updated constantly. In contrast, the capacity of each link or flowgate is determined by physical factors associated with the link (e.g. thermal limit, voltage stability, and dynamic stability) and is generally insensitive to the power flow pattern. Each power transfer requires approximately a constant fraction (known as the Power Transfer Distribution Factor, or PTDF) of the capacity of each link in the network. By combining the options discussed above, we can define transmission rights in four possible ways: (1) point-to-point (PTP) financial rights, (2) flow-based financial rights, (3) point-to-point capacity reservations, and (4) flow-based capacity reservations. In fall 1999, the California Independent System Operator (CAISO) auctioned tradable annual capacity reservations in the form of "firm transmission rights" (FTRs) that include refunds of usage charges and scheduling priority. These FTRs were flow-based rights defined on the major links in the transmission system. However, the power network in California was aggregated into zones while ignoring inter-zonal loop flows. Consequently, CAISO defined FTRs only on the interzonal links in the transmission network. Presently, CAISO uses a network model that is “radial” between the zones, but its definition of transmission rights and congestion charges enables looped networks to be handled as well. The current debates about tradable transmission rights have focused on the nature of the rights and the point-to-point definition.

In the following, we compare the flow-based approach with the point-to-point approach. Market participants can acquire flowgate (FGRs) and point-to-point (PTPs) financial transmission rights to hedge the congestion costs associated with their use of the transmission system. Ownership of transmission rights may or may not be required for the scheduling or use of the transmission system. These transmission rights can be financial in the sense that the right holder will be entitled to payment regardless of whether its transmission schedules or injections match its financial rights holdings. In many markets use-it or lose-it rules apply. Requiring that generators that follow dispatch instructions lose the value of their financial rights would reduce participation in the balancing market, raise the cost of meeting load and potentially undermine reliability. In some markets, market participants are able to acquire both flowgate and point-to-point rights in the form of either options or obligations. It is important to permit market participants to acquire financial rights defined as obligations, as well as options, so that the impact of counter-flows can be reflected in forward markets.

1.1.1 Point-to-Point Rights

1.1.1.1 Overview

PTPs are point-to-point financial transmission rights. Ownership of a PTP will entitle the holder to be paid the difference in the congestion components of the locational prices between the specific point or points of receipt and the specified point or points of injection. These payments may be subject to proration under some conditions. PTPs will be directional and may be defined either as obligations or options. PTP obligation holders will be entitled to payments based upon the difference in the congestion components of the locational prices when those differences are positive, and will be obligated to make payments when the locational differences are negative. It should be noted that when the difference in locational prices is negative, a transmission customer will be *paid* for scheduling transmission between the points specified in the PTP. There will therefore be no net cost for scheduling transmission service matching the PTP held by the transmission user, whether the difference in locational prices is positive or negative. PTP option holders will be entitled to payments based upon the difference in the congestion components of the locational prices when those differences are positive, but will not be obligated to make payments when the locational differences are negative.

PTP FTRs that are defined as obligations are essential for maximizing the efficient use of the grid. In essence, an obligation means that the holder may either have to pay the marginal cost of redispatch or provide the redispatch (in which case it will be paid the difference in locational prices). In either case, the counter-flow schedules associated with the obligation rights function to relieve constraints and hence allow other schedules to flow in the opposite direction. A system that offers at least some rights in the form of obligations will therefore expand access to the grid and allow more transmission rights to be allocated and more schedules to flow. Conversely, any system that offers rights only in the form of options will tend to reduce access to the grid, allow fewer rights to be allocated and permit fewer schedules to flow. Without the obligation to provide or pay for counter-flows, the grid will simply accommodate fewer transactions. When rights are defined as obligations, parties can be paid to take them. For example, a party accepting an obligation right (FTR or FGR) that is likely to have a payment obligation would be paid in the auction to take that right and, in effect, sell congestion management services (counter-flow/redispatch) forward. It is certainly acceptable, if the ISO defines some rights as options, as long as it also provides at least some rights as options. Ideally, an ISO should offer both and allow the market to determine the mix that best meets its commercial needs, including the degree to which some participants are willing to be paid to obligate themselves to provide or pay for counter-flows to expand grid usage.

PTPs are settled based on day-ahead prices and may be specified to be either node-to-node, node to market hub, market hub to node, hub to load zone or node to load zone. Node to node, node to hub and hub to node PTPs are settled based on the difference in the congestion components of the nodal prices at the destination and origin nodes, while node or hub to load zone PTPs are settled based on the difference between the congestion components of the load zone price at the destination and the congestion component of the nodal price at the origin. Load zone PTPs are settled based on the congestion component of the load zone price. Importantly, all PTPs (including load zone PTPs) can be awarded to and from specific nodes or a specific collection of nodes, but load zone PTPs are settled based on the congestion component of the zonal price.

The purpose of the FTR is to provide the customer with a financial hedge against potential congestion charges between any two points on the system. Assuming the FTR holder also scheduled energy between these two points (and in the same MW amount as the FTR), the congestion rent will exactly equal the congestion paid for the scheduled energy. In this way, an FTR holder can have price certainty on the delivery of energy scheduled in the day-ahead market. However, the payment of congestion rents is independent of actual energy scheduled. Therefore, holders of FTRs will be paid the applicable rents associated with the right, regardless of whether they schedule transmission service or not.

Proponents of PTP FTRs claim that converting Existing Contracts (ETCs) to FTRs is easier than converting them to FGRs. Certainly this was an important factor in determining the nature of the transmission rights in the RTO WEST markets. The argument is as follows: Suppose a current transmission customer has an ETC from point A to point B. Conversion of the ETC to an FGR or a portfolio of FGRs may be complicated and arbitrary. This portfolio will depend upon which constraints are binding and which set of PTDFs is applied. Identification of a portfolio of FGRs that is always equivalent to the pre-existing ETCs is therefore complicated and would require the ISO to regularly update the portfolio of existing FGRs. Alternatively, the ISO could simply issue PTP FTRs for the same two points covered by the ETC. The point-to-point FTRs would cover congestion charges between the two points no matter how the flowgates and the PTDFs have changed.

Proponents of PTP FTRs also make the claim that they offer full hedges and they provide a mechanism by which participants can obtain some degree of *ex ante* certainty with respect to either physical deliverability or price, or both. This is true because the PTP FTRs include insurance against changes in the grid configuration and the resulting changes in the PTDF matrix. This insurance may be called PTDF insurance. However, the cost of such insurance to other participants or the ISO of fulfilling the obligation inherent in such insurance could be substantial for major network changes. In the case of FGRs the ISO needs a mechanism to hedge congestion that cannot be predicted or covered by the FGR system alone. The combination of the correct mix of all the FGRs for the designated flowgates, plus the insurance of the PTDF matrix, would thus define a complete hedge for all congestion that might arise between two points. The exchange of one bundle of FGRs for another bundle of FGRs could be done in the bilateral market or through an organized "transmission rights exchange."

The numbers of PTP FTRs are constrained by simultaneous feasibility conditions which guarantee that congestion revenues can cover the FTR settlement (see section 3.1.). These conditions imply that some transmission capacity will be unsold and not all transactions can be hedged. Selling off all the available FGRs or both FGRs and PTP FTRs enables most of the transmission capacity to be sold off and all transactions to be hedged in the aggregate (although some transaction may be over-hedged while others under-hedged).

Key features of PTP FTRs are as follows:

- Ownership of an FTR entitles the holder to be paid the difference between the locational prices at the points of injection (POI) and points of withdrawal (POW). FTRs will specify a megawatt quantity and a term during which the FTR is in effect. FTRs will be unidirectional.
- All FTR holders will be entitled to payments based upon the difference in the congestion components of the locational prices when those differences are positive. For FTRs that are defined as obligations, the holders will also be obligated to make payments when the locational differences are negative.
- All transmission customers will be responsible for full congestion charges associated with their transactions. In this way, the proposed design treats all transactions, spot market and bilateral transactions, exactly the same. Transmission customers that hold FTRs will receive a credit against the congestion charges assessed to their transactions.
- PTP FTRs may be specified either node to node, node to market hub, market hub to node, or hub, node or load zone to load zone. Such FTRs will be settled based on the locational price differences of the appropriate node, load zone, or hub prices at the destination and origin locations specified in the FTR.

1.1.1.2 Simultaneous Feasibility

All FTRs outstanding at a given time must be simultaneously feasible. In other words, the transmission system under security-constrained conditions must be able to accommodate all the potential energy flows represented by an outstanding set of FTRs. The system constraints used in the modeling process for feasibility will be consistent with the model used in determining the day-ahead and the spot energy market LMPs. Simultaneous feasibility will be determined initially in the distribution process and reconfirmed in subsequent distributions, whether through auction or allocation.

FTRs for Firm Point-to-Point Service are modeled as generation at the receipt (POI or source) point(s) and load at the delivery (POW or sink) point(s). FTRs for Network Integration Service are modeled as a set of generators at the POI and a network load at the POW. Simultaneous Feasibility Tests (SFTs) are run for yearly, monthly, and weekly analysis periods, when network resource changes are submitted, and during the determination of the winning quotes for the FTR auction. Inputs to the SFT model include all newly-requested FTRs for the study period, all existing FTRs for the study period, any changes to the transmission network (e.g., new transmission facilities, transmission outage schedules), thermal operating limits for transmission facilities, ISO reactive interface limits that are valid for the study period, and estimates of uncompensated power flow circulation through the ISO Control Area from other Control Areas.

Consistent with ISO Operating and Planning criteria, the SFT evaluates the ability of all system facilities to remain within normal ratings during normal operation. The system must also be able to sustain any single contingency event with all system facilities remaining within applicable short-term, emergency ratings while maintaining an acceptable bulk system voltage profile.

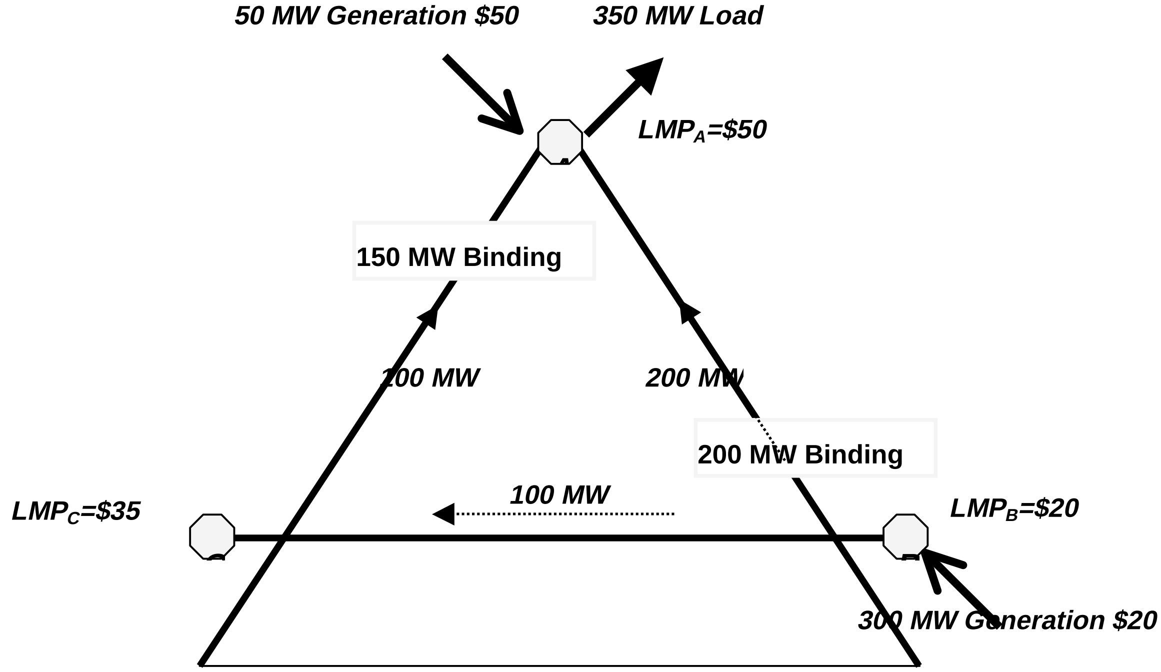
The application of the SFT to the allocation or auction of FTRs is intended to ensure that the congestion rents collected by the ISO that uses Locational Marginal Prices (LMP) to price congestion (and losses when LMP includes marginal losses) for transmission usage will be sufficient to honor payment obligations to FTR holders (as well as any Grandfathered Agreement rights that are not converted to FTRs). The congestion rent collections may nevertheless be insufficient to fund full payments to FTR holders if there are material transmission outages or unexpected uncompensated loop flows that reduce transfer capability below that which was assumed in the SFT. In these circumstances, the ISO will prorate transmission right payments after any funds in the congestion management account have been exhausted. Excess congestion rents collected in either the day-ahead or real-time market can be accumulated in the congestion management account that can be used to reduce the revenue requirement or fund future transmission upgrades.

The simultaneous feasibility conditions imposed on the FTRs typically include n-1 contingency considerations. That reduces the number of FTRs issued but does not increase the number of FTR types needed in order to offer perfect congestion hedges for any PTP transaction. In the case of flowgates, since every contingency changes the shift factors, a flowgate may be represented in the economic dispatch problem by multiple constraints corresponding to different contingencies. Thus, the number of commercially significant constraints may be as many as the number of flowgates times the number of relevant contingencies. If we define FGRs for each constraint in the economic dispatch problem we may end up with too many. However, it is possible to bundle constraints corresponding to different contingencies much like bundling parallel elements and cover each bundle with a single FGR. This approach can significantly decrease the number of FGRs issued by the ISO.

1.1.1.3 Point-To-Point (PTP) FTR Settlements

The payments associated with point-to-point rights can also be illustrated using the example above. Consider a transmission customer with 15 PTPs from B to A that schedules a 15MW transaction from B to A. Given the LMP prices in Figure 1, the transmission customer would pay $30 ($50-$20)/MWh * 15 MW for transmission usage and would also receive $30 * 15 for its ownership of 15 B to A PTP rights. In effect, the transmission congestion costs incurred by the customer would be limited to whatever the customer paid to acquire the PTP right and would not vary with actual congestion levels.

Figure 1



A significant feature of PTP FTR rights is that the PTP FTR holder is hedged against congestion between B and A, regardless of which constraint is binding. Recall the prior example of the impact of the operation of the generator at node C in creating congestion on the line C-A, as portrayed in Figure 6. In this circumstance, the transmission customer holding 15 PTPs from B to A would be fully hedged, receiving PTP payments of 15 * $30, and paying transmission usage charges of 15 MWh * $30.

1.1.2 FGR Forward/LMP Based Markets

When an FGR forward market is superimposed on an LMP based market, certain rules need to be put in place to ensure the workability and efficiency properties of the market. The most important of these rules are:

The ISO should pay special attention to the designation of "commercially significant constraints." The ISO should not unilaterally determine what is commercially significant. It should develop a process to dynamically include the most important flowgates in the model. This will improve the likelihood that the forward markets will effectively manage congestion and not leave substantial residual congestion for the ISO to manage in real time.

The RTO should minimize the congestion costs uplift. This will ensure the validity of the locational price signals reliable operations and long-run investments.

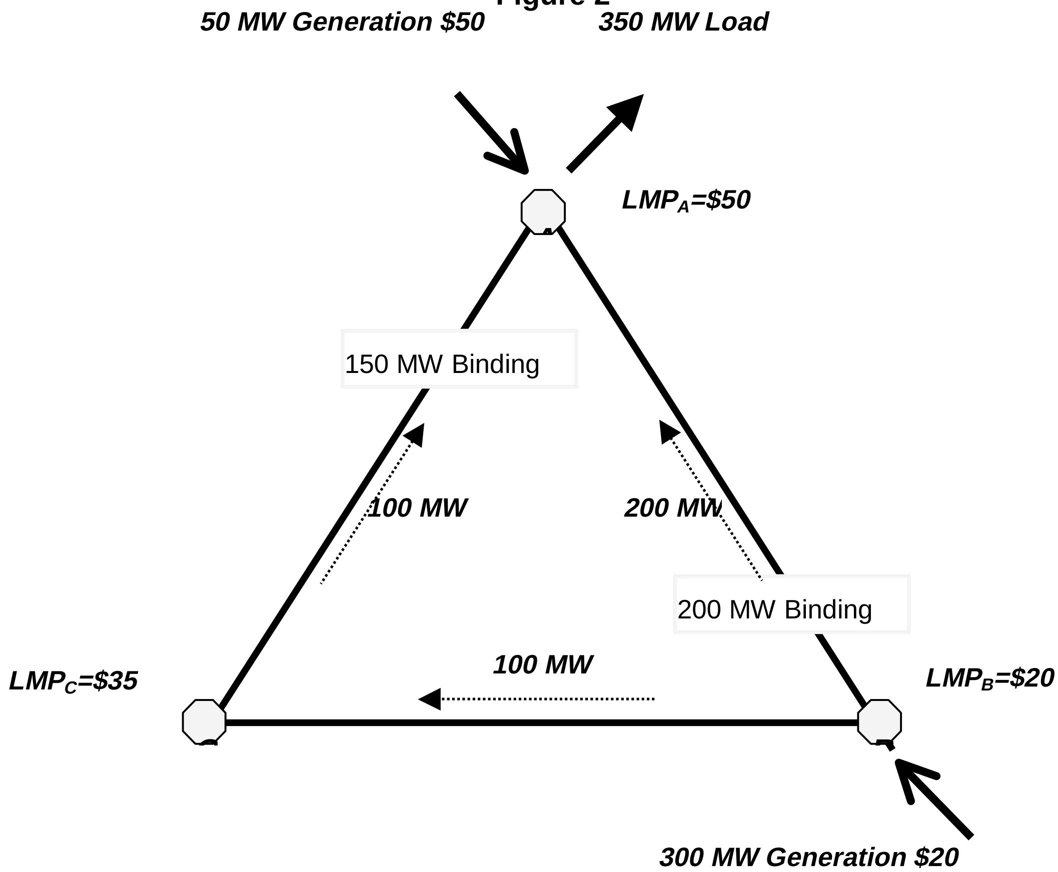
The ISO should discard the "use-it-or-lose-it" rule and instead credit rights holders with the value of their rights whether or not the rights match a given schedule. This will remove needless and costly requirements for rights trading, improve the efficiency of the dispatch, and allow participants greater commercial freedom.

Both options and obligations should be allowed. This will provide the market participants the ability to buy and sell counter-flow congestion management forward and to allow full utilization of the grid. Furthermore, market participants who wish "full coverage" -- financial certainty for all congestion costs from their point of receipt to their point of delivery- should be allowed to purchase in addition to constraint-specific FGRs, PTP FTRs. In some cases, a single PTP FTR may be easier to acquire and trade than near-equivalent bundles of FGRs.

1.1.3 LMP PRICING

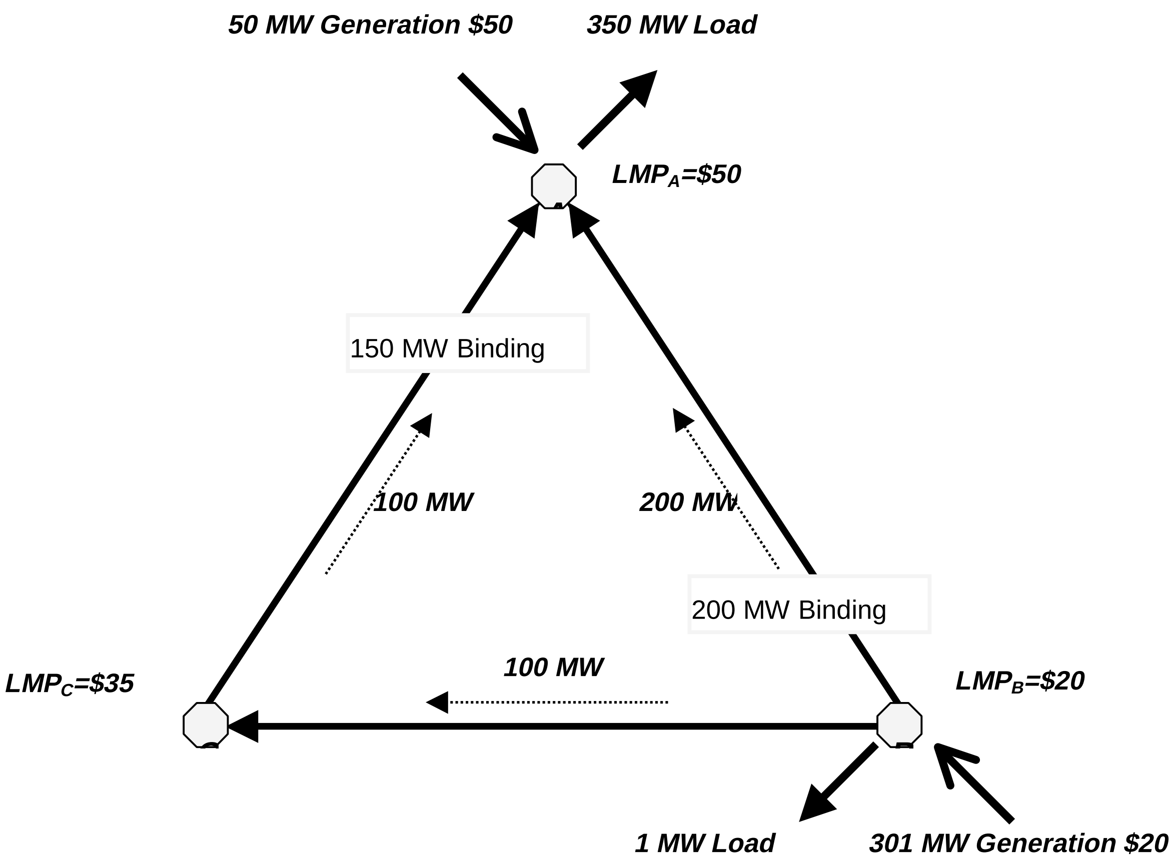
The determination of LMP prices is illustrated in Figure 2. In this example, a transmission constraint is binding on line B-A. Therefore, additional load at A cannot be met with the low cost generation from node B. For simplicity, assume that the lines B-A, B-C and C-A have equal reactance and zero resistance. The LMP prices are $20 at B, $50 at A and $35 at C.

Figure 2



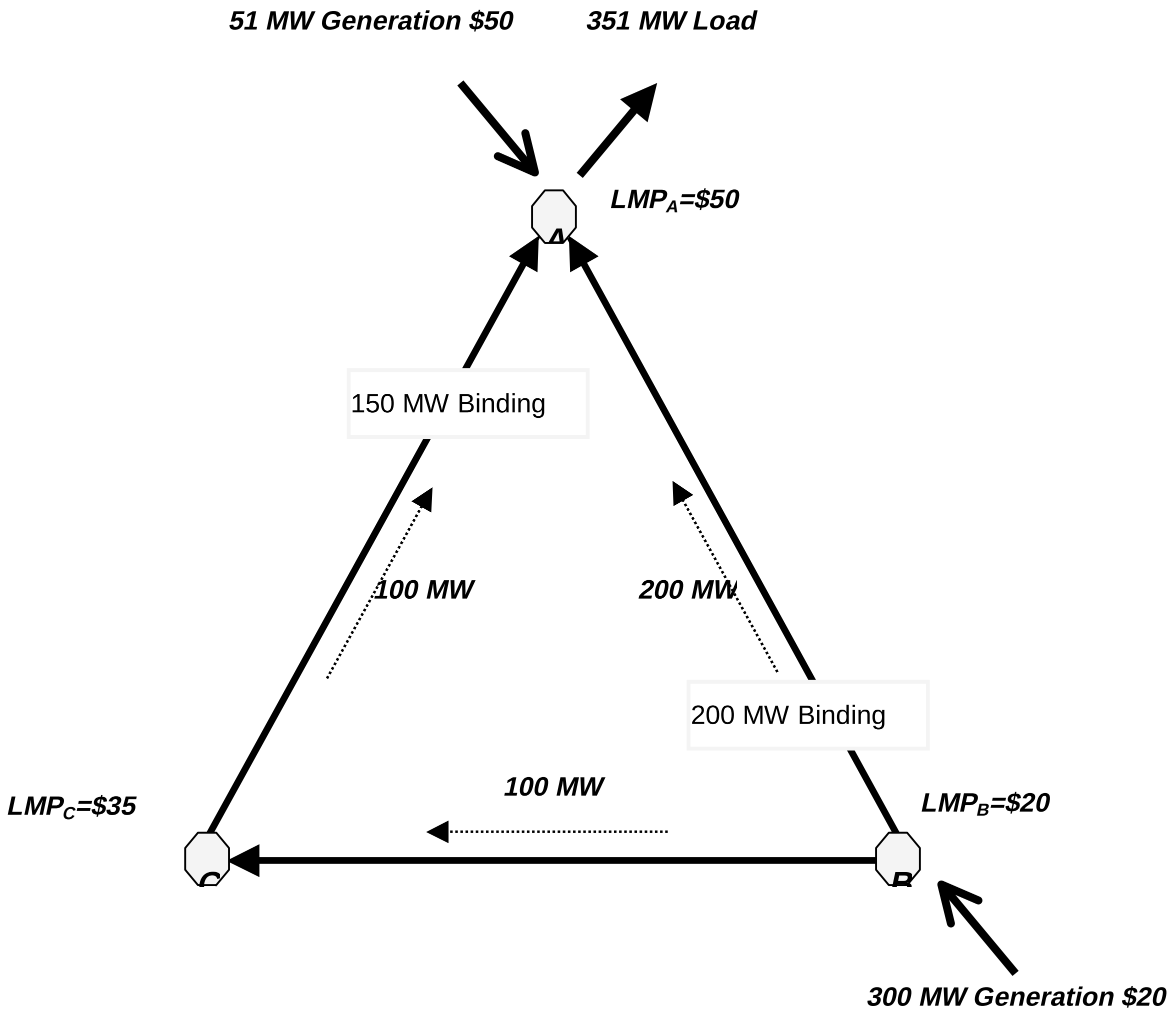
The usage charge for transmission from B to A would be \$30/MWh (\$50 - \$20). The incremental cost of meeting load at B is \$20, because an incremental MW of load at B could be met by increasing generation at B without overloading the constraint on line B-A, as shown in Figure 3.

Figure 3



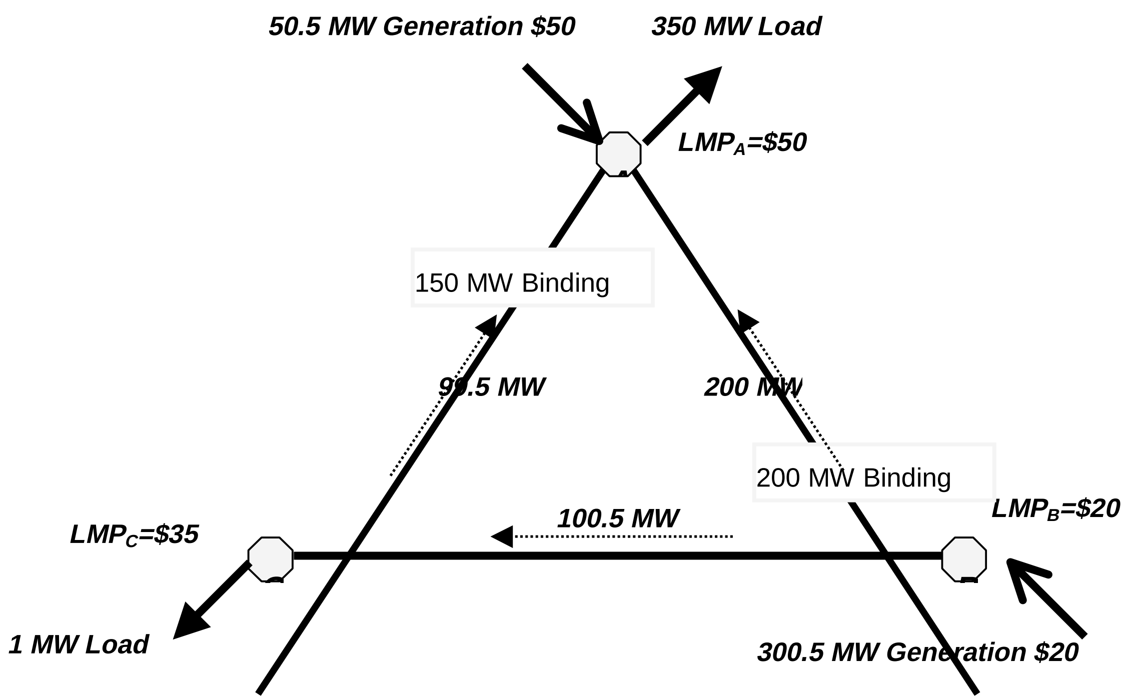
Similarly, the incremental cost of meeting load at A is $50/MWh, because an incremental MW of load at A must be met with the high cost generation at A, as shown in Figure 4. Any increase in generation at B would overload the line B-A.

Figure 4



Finally, the incremental cost of meeting load at C is $35/MWh, because an incremental MW of load at C would be met at least cost by increasing injections at A by .5 MW and by B by .5 MW. The total cost of these injections is $35/MW (.5*$50 + .5 * $20).

Figure 5



The calculation of the prices at the nodes of figure 4 is as follows. Assume zero losses for simplicity. For simplicity also assume, that Bus B is the reference bus. The price at bus B is therefore the sum of the price at the reference bus ($20) and the shift factor on the constrained line for meeting load at bus B with generation at the reference bus times the shadow price of the constrained line. Since bus B is the reference bus, there are no flows on the constrained line in meeting load at bus B with generation at bus B and the shift factor on the constrained line is zero. The price at bus B is therefore the price at the reference bus, or $20/MWh.

The price of energy at bus A is equal to the sum of the price at the reference bus ($20) and the shift factor on the constrained line (for meeting load at bus A with generation at the reference bus) times the shadow price of the constrained line. In this case, however, meeting a MW of load at A with generation at the reference bus would produce flows of 2/3 MW on the constrained line. Therefore, the shift factor is 2/3. The shadow price of the constrained line is the change in the total cost of meeting load from increasing the limit on the constrained line by 1MW. A 1MW increase in the limit on the line B-A would permit an additional 1.5MW to be injected at B and permit a corresponding reduction of 1.5 MW in injections at A. The change in the cost of meeting load would therefore be:

+1.5 * $20 – 1.5 *$50 = $45.

Therefore, the price at bus A is:

$20 + 2/3 * $45 = $50.

Finally, the price at bus C is equal to the sum of the price at the reference bus ($20) and the shift factor on the constrained line (for meeting load at bus C with generation at the reference bus) times the shadow price of the constrained line. In this case, however, meeting a MW of load at C with generation at the reference bus would produce flows of 1/3 MW on the constrained line. Therefore, the shift factor is 1/3.

Since the shadow price of the constrained line is $45 in the example, the price at bus C is:

$20 + 1/3 * $45 = $35.

1.1.4 Flowgate Rights

Several of the emerging ISO proposals around the nation recognize the merit of having flowgate transmission rights (FGRs) if not exclusively then in conjunction with PTP transmission rights (FTRs). FERC staff in their white paper outlining their vision for a standardized market design has recently endorsed this pluralistic approach. Yet the debate surrounding this subject is raging with arguments that tend to be misguided and technically incorrect. For instance, many believe that FGRs are physical rights whereas FTRs are financial. Likewise, some believe that FGRs require socialization of congestion cost whereas FTRs represent direct assignment of such costs. The fact is that both FTRs and FGRs can be defined as financial rights that can be settled on the basis of locational marginal cost pricing of transmission assets. While FTRs are entitlements (or obligations) to the nodal price difference between two locations on the network, the FGRs are entitlement to the shadow price on one or more flow constraints imposed on the economic dispatch. In either case the rights can be defined as financial rights that are settled on the basis of locational prices (nodal or shadow prices) without direct impact on actual operation. Admittedly some proponents of FGRs have also advocated that the rights be physical with a "use it or loose it provision" or that the settlements be based on averaged shift factors while socializing the cost implication of the deviation between the real time and the average shift factors. Such proposals are misguided and do not represent what FGRs are all about.

Some market design proposals in emerging ISOs have suggested that both FTRs and FGR be offered as options and as obligations. The reasoning is that a flowgate-based system cannot provide full hedges in counter-flow situations unless somebody holds negative-valued FGRs that entail the same perform-or-pay obligations required with a negative-valued PTP FTRs. If the ISO cannot issue negative-value FGRs for some reason full hedging in the presence of counter-flow requires that negative-value rights or obligations be somehow defined and administered. As a matter of fact, negative value PTP FTRs are commonly bid for and sold in the PJM FTR auctions.

In some markets flowgate based financial transmission rights (FGRs) are established, which are directional, and defined in the form of both FGR options and FGR obligations. An FGR option will entitle the holder to the payment of the constraint shadow price for that flowgate if the constraint shadow price is positive, but will not obligate the FGR option holder to make any payment to the ISO if the constraint shadow price is negative.

An FGR obligation will entitle the holder to the payment of the constraint shadow price for that flowgate if the constraint shadow price is positive, but will also obligate the FGR obligation holder to pay the constraint shadow price to the ISO in the event that the constraint shadow price is negative. These payments, like payments to PTP rights holders, may be subject to proration in some circumstances such as derating of the transmission capacity.

FGRs are settled based on day-ahead prices. The payment associated with an FGR will hedge the holder against transactions impacting the specific flowgate associated with that FGR but will not hedge the holder against congestion on other constraints. If the FGR ownership were allowed to insulate the holder against congestion on constraints not defined as flowgates, it would undermine the market and expose ISO participants to large uplift costs arising from gaming behavior.

Furthermore, FGRs could be defined as a monitored element (i.e., a PTDF flowgate) or as a specific combination of a monitored element and a contingency element (i.e., an OTDF flowgate). An OTDF flowgate can be defined in terms of the post contingency flows on a specific monitored element in the event of a specific contingency. In most cases, there will be a single worst contingency for each monitored element; however, this will not always be the case. Defining FGRs as specific monitored element contingency element pairs will enable market participants to acquire only those FGRs required to hedge their transactions. In the case of OTDF flowgates, the shadow price that values the FGR will be the post-contingency shadow price of flows on the monitored element.

Market participants wishing to be fully hedged against congestion would be able to acquire point-to-point (PTP) financial rights. Because a flowgate right entitles the holder to the payment of a specific constraint shadow price, hedging a specific point-to-point transaction with FGR ownership will require that the market participant acquire sufficient FGRs to hedge the congestion charges associated with that transaction, given the shift factors (i.e., PTDFs) that would apply to the calculation of congestion charges. Usually the assessment of the number of flowgate rights that would be required to hedge the congestion risk, associated with a particular transaction, will be made by the market participant. In this case, the ISO will provide historical information that could be used by market participants to assess likely flowgate requirements but the ISO will not provide any guarantees regarding shift factors (i.e., PTDFs) or required FGR ownership. Thus, market participants holding flowgate rights will be paid the constraint shadow price of that flowgate. This payment will not be adjusted upwards or downwards depending on the shift factors (i.e., PTDFs) associated with any particular transaction. Market participants not desiring the flexibility of flowgate rights and seeking to hedge particular transactions against congestion without regard to changes in shift factors (i.e., PTDFs) may do so by acquiring point-to-point rights.

1.1.4.1 FGRs: Pros and Cons

Proponents of flowgate rights claim that FGRs have the following main advantages over the PTP transmission rights:

- FGRs can be defined independently of the power flow patterns
- In an FGR model only congested links require a financial settlement
- FGRs have only positive value unlike a PTP FTR (depending on the formulation)
- The FGR based model ensures liquidity and facilitates decentralized trading

We briefly comment on the above issues. It is clear that the amount of FGRs on a specific element is not sensitive to the topology of the network or to varying load conditions. The market value of such rights varies, of course, but the physical availability of transfers does not. Hence, the quantities of available rights do not need to be frequently re-evaluated with respect to simultaneous feasibility constraints (as in the PJM power pool). Therefore, they are relatively stable over time. One can view each PTP FTR as an equivalent to a portfolio of FGRs, but an FGR cannot be decomposed into PTP FTRs in general. In addition, since flowgate rights are more stable over time, they are more tangible to the owner, providing greater investment incentives than point-to-point rights to those who might build transmission. The flow-based specification of transmission rights is consistent with the existing NERC protocols for transmission load relief (TLR) and with direction of the current NERC proposals for transition to a flow-based alternative that would align transmission reservations and energy schedules to actual flow and existing transmission loading relief procedures.

Furthermore, in a congested network that is meshed even one congested element may cause each pair of nodes to have different prices and therefore require financial settlement of each PTP. On the other hand when rights are defined in terms of FGRs only rights corresponding to the congested flowgates are entitled to financial compensation. Typically the number of important flowgates that can capture most of the congested rents is relatively small compared to the number of nodes. Therefore, in a FGR model the number of rights needed to provide each user the ability to hedge against commercially significant congestion risk and secure scheduling priority is relatively small. This is very critical because if the number of forward instruments needed to provide coverage is small, then the developed hedging mechanism enhances market liquidity and improves efficient trading of risk management contracts. Moreover, once the shadow prices of flowgate rights are known, it is straightforward to derive nodal prices. However, the converse is not true. Therefore, flowgate rights offer greater price transparency than point-to-point.

In principle, the value of FGRs can never be negative, unlike the value of PTP FTRs. If a flowgate for which a right has been issued is not congested in the direction corresponding to the right then the right has no value. However, a PTP FTR can have a negative value and can result in a financial liability. The reason is that a PTP FTR is a portfolio of “short” and “long” link-based forward contracts that are needed to support a PTP transfer of power as determined by the PTDF matrix of the network. Such a portfolio can have either positive or negative value. PTP FTRs with negative values decrease price certainty but are critical to fully utilize the transmission network. The reason is that the transfer capability between two points may be greatly diminished unless a system with point-to-point rights with negative values is established. This means that a PTP FTR system with non-negative prices can lead to a grossly underutilized transmission network. On the other hand, the available number of flowgate rights on a link is determined only by the contingency-adjusted flow constraints on that link independently of the rest of the transmission grid. This line of reasoning gives credence to the claim that a PTP FTR system cannot fully support a decentralized market framework.

Furthermore, due to the fact that FTRs are subject to simultaneous feasibility (see section 3.1) they may have limited liquidity. Experience at PJM confirms that there is virtually no secondary trading of FTRs and most of the trading takes place through the periodic reconfiguration auctions conducted by the ISO. FGRs on the other hand are linked to physical capacity of one or groups of elements, which is determined separately for each FGR. Furthermore, it may be the case, depending on the characteristics of the specific transmission grid, that the number of flowgates that are commercially significant is limited. Consequently, in that case, most of the point-to-point congestion can be traced to a small number of bottlenecks. To the extent that these bottlenecks are persistent and predictable, the ISO can issue for them FGRs over long durations whereas any reconfiguration can be handled by secondary trading. The limited number of FGRs and the fact that their available quantities are determined independently for each FGR makes them liquid and amenable to segmentation (into hourly or daily rights) and secondary trading.

However, there are several serious concerns inherent in a FGR based system. Successful implementation of such a system requires resolution of the following problems, that if they are not solved, they have the potential to substantially reduce the value of a FGR-based system:

Complexity: Coverage of a trade requires, possibly, the purchasing of FGRs on a substantial number of elements in the entire transmission grid. This requirement complicates trading and increases substantially the information processing cost to the point that it may make this approach impractical. As a result the market transaction costs may be prohibitively high. Even with the rapid technological advances in metering and other information technologies this issue is serious and deserves substantial attention. Furthermore, the ISO will need to manage the remaining or unexpected congestion using what is essentially a real time LMP/FTR system. Thus, far from being an ***alternative to*** the type of LMP/FTR system operated by PJM and others, the flowgate/FGR system ***requires*** such a system to manage unhedged congestion. This adds further complexity to the FGR model.

Also, the fact that the MW quantity of FGRs on each flowgate may be relatively stable, it does not ensure the stability of the overall system for traders, because changes in the market or the network can change the portfolio of FGRs needed to hedge an unchanged set of transactions. Proponents of the PTP FTRs claim the commercial stability of the FGR system under such conditions has limited value. On the other hand, in a PTP FTR system trading patterns and the resulting congestion can change, but this does not require new FTRs or PTDF tables. Simply, in that case, the ISO determines the new optimal bid-based dispatch and LMPs without regard to the FTR. If commercial trading patterns change enough, the ISO can offer the service of reconfiguring FTRs through a central auction, but no trader gives up any rights in this process without getting in return something that it values more highly.

Initial designation of FGRs: The FGR based model relies heavily on the assumption that the number of commercially significant elements is small in order to lead to simplified forward markets and efficient decentralized trading. However, the initial designation of FGRs in a few out of the many transmission constraints may be cumbersome, and in some cases, especially in meshed transmission grids, arbitrary. Granted, historical congestion could be a powerful indicator of future potential FGR elements, but in many cases market conditions change and this may substantially impact existing FGR holders. A methodology is clearly needed to designate the commercially important paths for which hedging is required. Furthermore, a methodology is needed to determine how congestion costs resulting from unhedged congestion on constraints that are not designated as flowgates, are allocated.

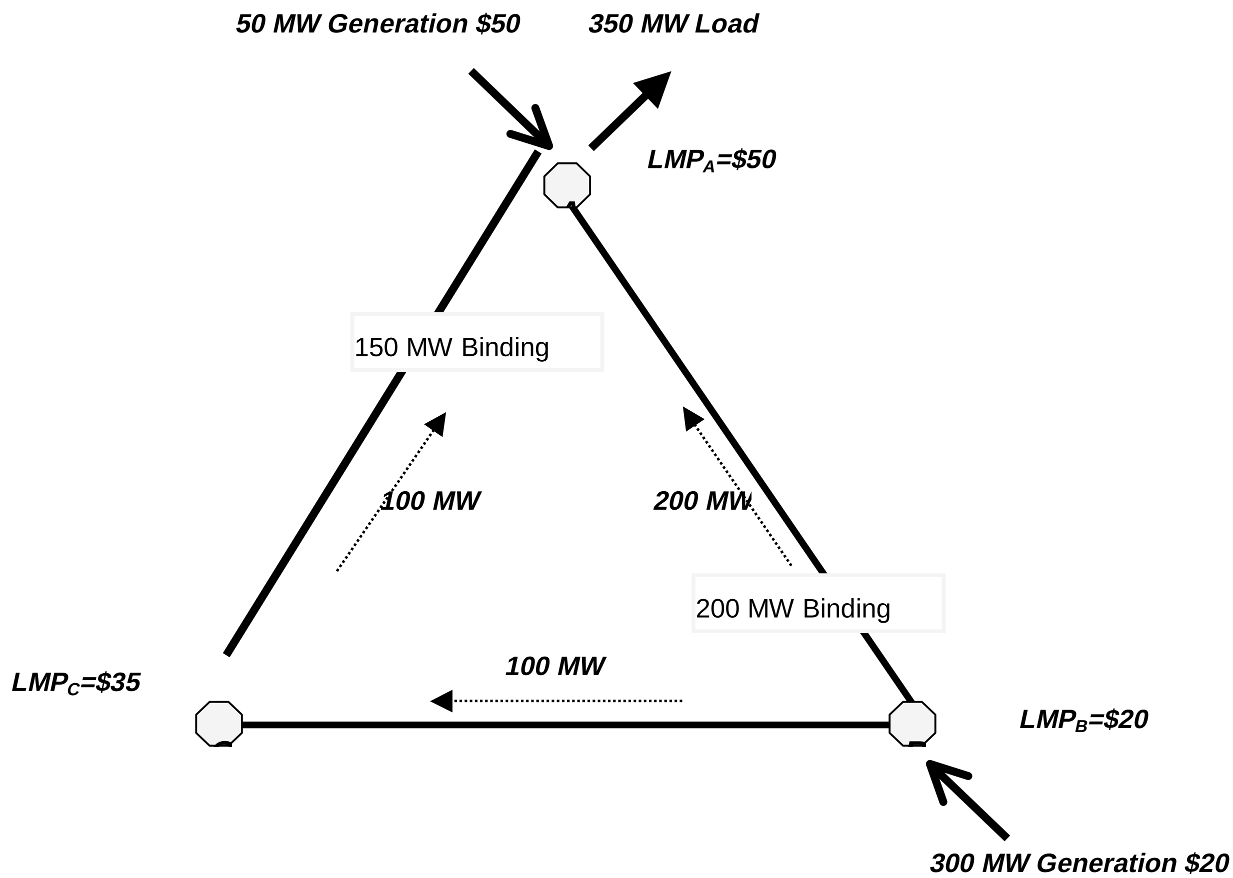
Decentralized price discovery limitations: To ensure that the full value of transmission rights and counter-flows are realized it is critical to establish a centralized market to clear the market to solve for congestion. This recognition that a centralized mechanism is need for efficient operations discredits to some extent the argument that flowgate/FGR system encourages decentralized price "discovery" and facilitates decentralized trading.

Cost socialization: The simplified forward market would provide no hedge against real-time congestion of the constraints it ignores. If traders do want to hedge against non-flowgate congestion, they need real-time FTRs administered by the ISO to do so. Therefore, an artificially simplified forward market does little for traders unless the ISO is going to absorb or socialize the costs of managing the constraints assumed away in that market. The problem may not be substantial if indeed the number of flowgates required for hedging is small and predictable. However, it is expected that the ISO will be under continuous and intense pressure from large and influential entities to make forward trading simple and meaningful by designating few flowgates and then absorbing or socializing the costs of managing non-flowgate congestion. Therefore, to make the whole FGR system work in its entirety the ISO needs to define a set of flowgates that is simultaneously (1) small enough that decentralized trading can find an efficient solution quickly; (2) stable enough that flowgates, FGRs or PTDFs, and hence FGR portfolios, do not have to be redefined often; and (3) comprehensive enough that non-flowgate congestion really is commercially insignificant. For transmission grids that are not highly meshed such requirements can be met successfully. Otherwise, this becomes a difficult task indeed.

1.1.4.2 Flowgate Rights (FGR) Settlements

The payments associated with FGR ownership can be illustrated using the same example used to illustrate LMP prices. As we discussed earlier, the shadow price of the line B-A was $45. Each FGR on line B-A held by a transmission customer would entitle the customer to be paid $45.

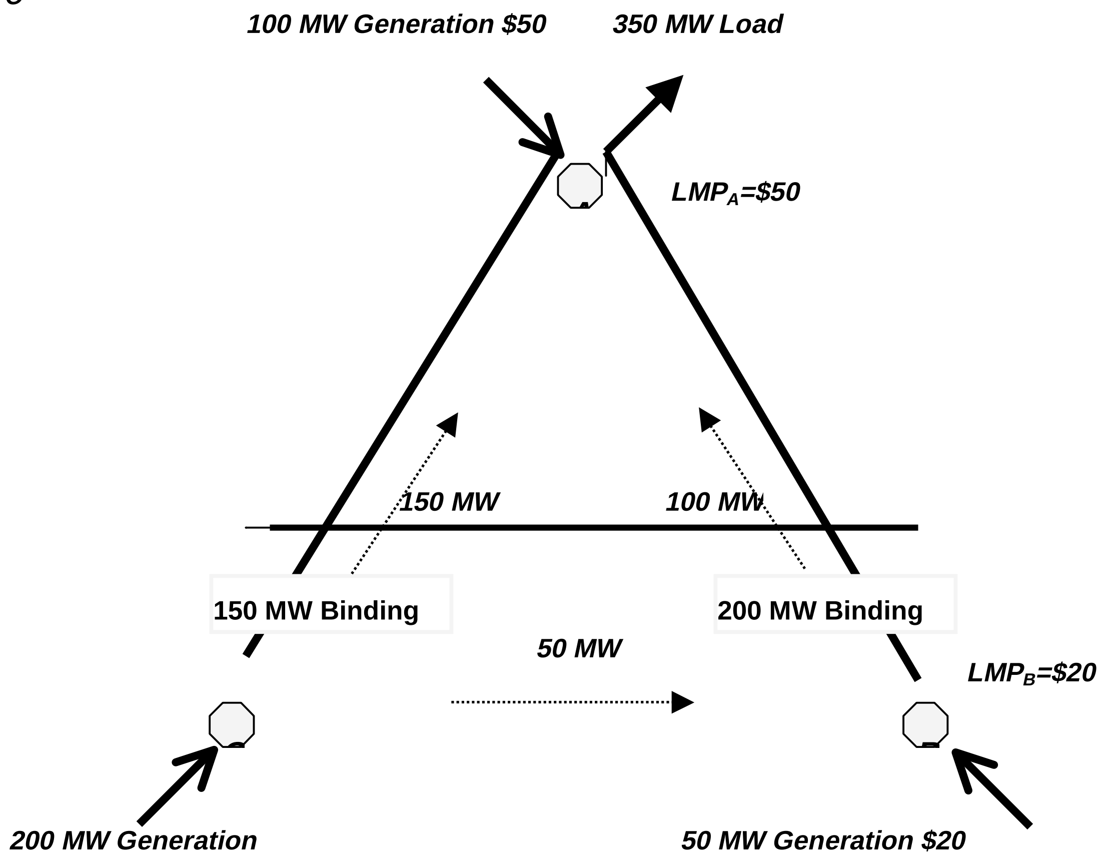
Figure 5



If the transmission customer wished to schedule 15 MW from B to A, it would be charged $450 for transmission usage (15MW * [$50 - $20]). These charges would be hedged by ownership of 10 FGRs (15*2/3) on B-A. That is, the transmission congestion costs it would incur would be limited to whatever the customer paid to acquire the FGR and would not vary with actual congestion levels. If the actual shift factors were expected to be 2/3, then the number of FGRs on B-A required to hedge a transaction from B-A would be 2/3 * the MW of the transaction.

It is important to remember that the payment associated with an FGR will hedge the holder against transactions impacting the specific flowgate associated with that FGR but will not hedge the holder against congestion on other constraints. Thus, in the example if a transmission customer held 10 FGRs on B-A to hedge a 15 MW transaction from B-A, it would be fully hedged if the binding constraint were on B-A as in Figure 5 above. Suppose now that a generating unit started operating at node C causing congestion on the C-A line as shown in Figure 6. In this circumstance, the shadow price of the constraint on the line B-A would be zero, and the FGRs on the line B-A would not hedge the congestion charges on a transaction from B to A.

Figure 6



1.2 SEAMS ISSUES with RTO West FTOs

The value of FTOs is not dependent upon whether the Scheduling Coordinator holding the FTO submits a schedule request that precisely corresponds to the injection and withdrawal locations specified in the FTO. The credit value generated by a particular FTO may be used to offset congestion charges resulting from any schedules a Scheduling Coordinator has submitted during the hour specified in the FTO. The specific design of FTOs in the RTO West markets is intended to encourage schedule requests to correspond more closely to the physical capability of the transmission system. In general, RTO West believes that PTP FTRs designed differently that the FTOs provide no incentive to establish a linkage between physical use of the system and the value of an FTR. FTOs, on the other hand, have no credit value unless the holder has incurred congestion charges through submitting actual schedules. Connecting congestion charge hedges to the physical system provides a better mechanism for constraining proposed dispatch. Only schedules with matching physical energy flows can realize the full value of an FTO. This will encourage market participants to submit schedules that do not require large amounts of redispatch. It will also promote more efficient trading in FTOs, because an FTO holder that does not intend to submit schedules that correspond to the FTO will have a strong incentive to resell the FTO to another market participant that does.

In summary, the RTO West FTOs have the following key characteristics:

- are financial options, not physical rights;
- are defined with respect to particular injection and withdrawal locations on the RTO West transmission system;
- can be redeemed to receive credits against congestion charges but cannot result in an obligation to pay RTO West a “negative” value;
- are flexible because their credit value can be applied against any congestion charges a Scheduling Coordinator incurs during the operating hour to which the FTO relates, not just charges resulting from a schedule to inject and withdraw energy at the locations defined in the FTO;
- do not give the right to the FTO holder to receive cash independent of whether the Scheduling Coordinators that holds the FTO has incurred congestion charges; i.e., they have value only to the extent that they are redeemed to receive credit against congestion charges; and
- are freely tradable in secondary markets.

If a seamless West-wide Market is a future objective, an RTO West compatible, FTO-based, transmission rights framework in California may be more appropriate than a PJM style, PTP FTR system based on obligations, assuming RTO West is successful in gaining FERC approval for an approach that may not be very consistent with FERC’s preferred Standard Market Design.

2 FTR Examples

2.1 Revenue Neutrality Issue

Consider the 3-bus network of Figure 1 where three Generators at buses A, B, and C compete to serve the Load at bus C. Assume that the three transmission lines have equal impedance. Then, the power transfer from one bus to another splits 2/3 on the short path and 1/3 on the long parallel path. Assume also that Line A→C is rated at 100 MW capacity.

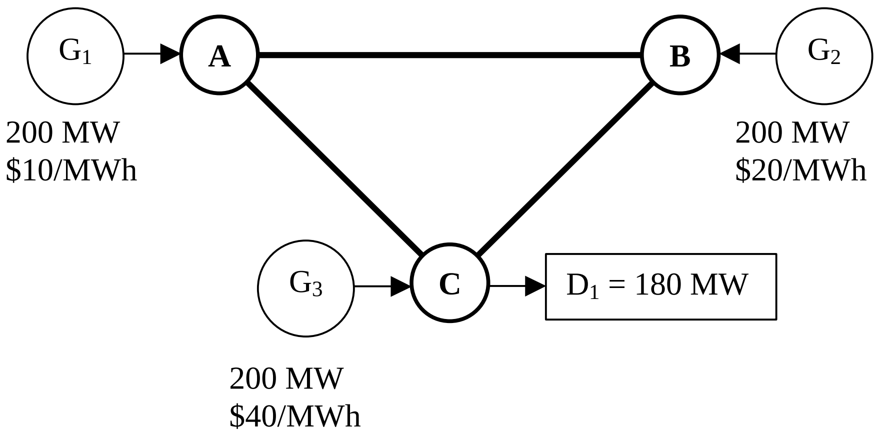


Figure 1. **3-bus network**

The cheapest source of power is G_1, however an injection of 180 MW at Bus A will result in a 120 MW flow on Line A→C and thus a 20 MW transmission violation. To remove that violation, power can be exchanged between G_1 and G_2, the second cheapest source of power. Shifting 3 MW of generation from G_1 to G_2 would reduce the violation by 1 MW at a cost of $30/MWh. Therefore, to eliminate the violation 60 MW of generation should shift from G_1 to G_2. Figure 2 shows the optimal constraint solution and the resulting nodal energy prices and shadow transmission prices.

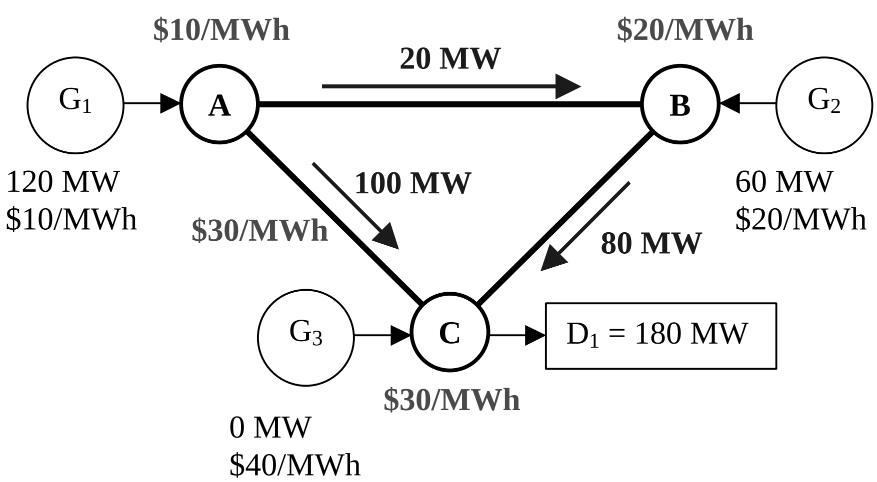


Figure 2. **Optimal schedule**

The nodal prices at Buses A and B are the bids of the corresponding generators that are marginal. The nodal price at Bus C is the cost of serving an additional MW of load. A 3 MW generation shift from G_1 to G_2 would release 1 MW of transmission capacity on Line A→C that then can accommodate a 3 MW additional power from G_2 to serve 3 MW of additional load at Bus C for a net cost of $90/h, or $30/MWh.

Assume that FTRs are auctioned on this network and that G_1 and G_2 purchase the point-to-point FTRs that need to fully hedge against congestion for the optimal schedule of Figure 2. Then, G_1 acquires 120 MW FTR from Bus A to Bus C, and G_2 acquires 60 MW FTR from Bus B to Bus C. Then at a given hour in the forward market both generators receive FTR payments for the energy price differences between Bus C and their own bus, effectively insulating themselves from the cost of congestion (their energy is effectively paid $30/MWh).

A point-to-point FTR is equivalent to a portfolio of FGRs on each network branch. Using the PTDFs of the network in Figure 1, the A→C FTR of G_1 includes an 80 MW FGR on Line A→C and the B→C FTR of G_2 includes an 20 MW FGR on Line A→C. The FGR payment is at the shadow transmission prices. Table 1 shows the settlement using point-to-point FTRs or FGRs.

Table 1. **Basic settlement**

Resource	Energy Settlement	FTR Payment	FGR Payment
G_1	–120 × $10 = –$1,200	120 × $(30 – 10) = $2,400	80 × $30 = $2,400
G_2	–60 × $20 = –$1,200	60 × $(30 – 20) = $600	20 × $30 = $600
G_3			
D_1	180 × $30 = $5,400		
Total	**$3,000**	**$3,000**	**$3,000**

The outcome is revenue neutral irrespective of which method is used.

Changes to Resource Patterns or Bids

Assume that in a given hour G_2 is out of service. Figure 3 shows the optimal schedule, the nodal energy prices, and the transmission shadow prices.

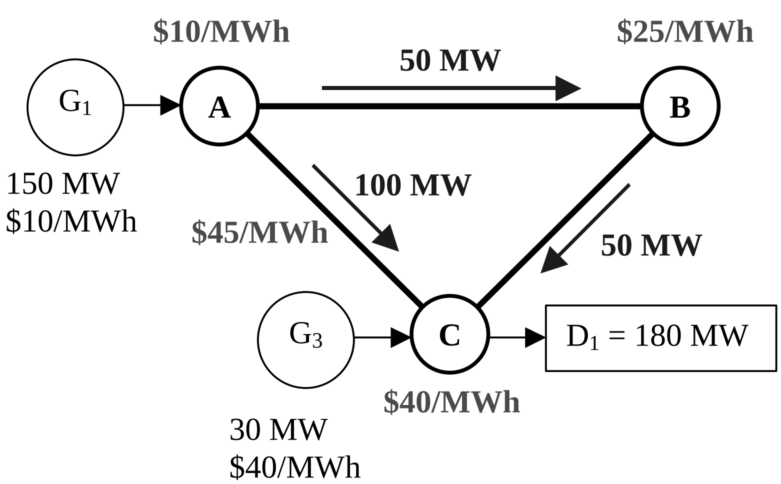


Figure 3. **Optimal schedule after resource pattern change**

As shown in Table 2, the settlement using point-to-point FTRs or FGRs is again revenue neutral. Therefore, changes to resource patterns or bids do not alter the value of FTRs or FGRs as long as there is no impact on the transmission network.

Table 2. **Settlement after resource pattern changes**

Resource	Energy Settlement	FTR Payment	FGR Payment
G_1	–150 × \$10 = –\$1,500	120 × \$(40 – 10) = \$3,600	80 × \$45 = \$3,600
G_2		60 × \$(40 – 25) = \$900	20 × \$45 = \$900
G_3	–30 × \$40 = –\$1,200		
D_1	180 × \$40 = \$7,200		
Total	**\$4,500**	**\$4,500**	**\$4,500**

Changes to ATC on Congested Path

Assume that in a given hour the ATC on Line A→C is reduced to 60 MW (loss of one of two parallel circuits), the power transfer from Bus A to Bus C now splits evenly (½) on the short path (A→C) and the long path (A→B→C), and the power transfer from Bus B to Bus C now splits ¾ on the short path (B→C) and ¼ on the long path (B→A→C). Figure 4 shows the optimal schedule, the nodal energy prices, and the transmission shadow prices.

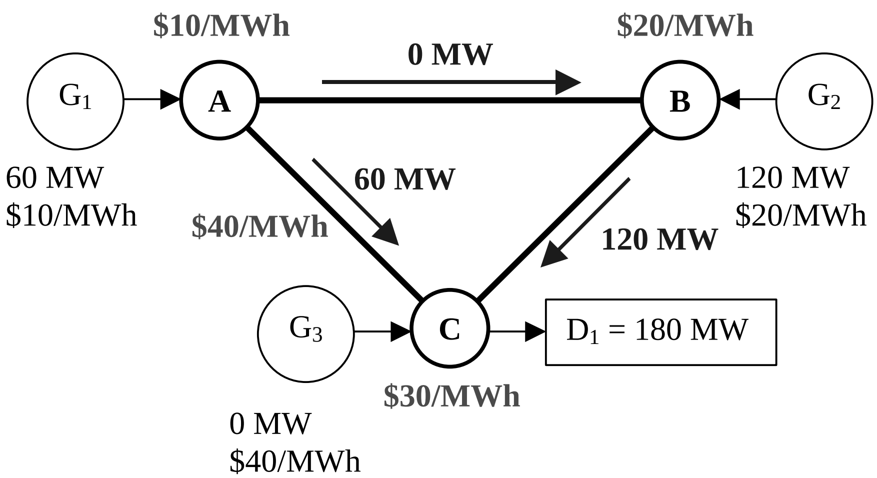


Figure 4. **Optimal schedule after ATC change**

As shown in Table 3, the settlement using point-to-point FTRs is no longer revenue neutral.

Table 3. **Settlement after ATC change**

Resource	Energy Settlement	FTR Payment	FGR Payment
G_1	–60 × \$10 = –\$600	120 × \$(30 – 10) = \$2,400	48 × \$40 = \$1,920
G_2	–120 × \$20 = –\$2,400	60 × \$(30 – 20) = \$600	12 × \$40 = \$480
G_3			
D_1	180 × \$30 = \$5,400		
Total	**\$2,400**	**\$3,000**	**\$2,400**

Using FGRs, however, if the FGRs on Line A→C are reduced by 40% to reflect the reduction of ATC on that line, the settlement would be revenue neutral.

In this case, it is reasonable to reduce the FGRs (and thus the corresponding point-to-point FTRs) since the ATC is reduced. Alternatively, the FTR holders may be paid fully and the difference of $600 can be recovered by uplift.

Changes to Power Transfer Distribution Factors

Assume that in a given hour one of the two parallel circuits of Line A→B is lost and as a result the power transfer from Bus A to Bus C now splits ¾ on the short path (A→C) and ¼ on the long path (A→B→C), and the power transfer from Bus B to Bus C now splits ¾ on the short path (B→C) and ¼ on the long path (B→A→C). Figure 5 shows the optimal schedule, the nodal energy prices, and the transmission shadow prices.

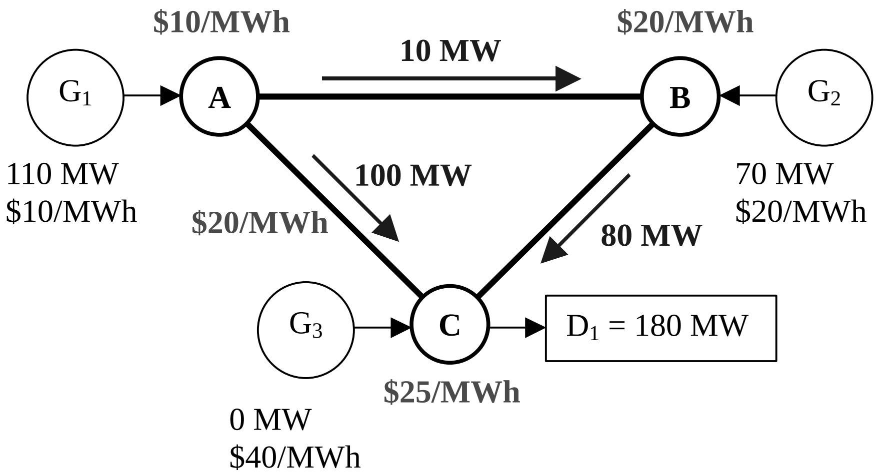


Figure 5. **Optimal schedule after PTDF change**

As shown in Table 4, the settlement using point-to-point FTRs is no longer revenue neutral. Using FGRs, however, the settlement would be revenue neutral. Alternatively, the FTR holders may be paid fully and the difference of $100 can be recovered by uplift.

Table 4. **Settlement after PTDF change**

Resource	Energy Settlement	FTR Payment	FGR Payment
G_1	–110 × $10 = –$1,100	120 × $(25 – 10) = $1,800	80 × $20 = $1,600
G_2	–70 × $20 = –$1,400	60 × $(25 – 20) = $300	20 × $20 = $400
G_3			
D_1	180 × $25 = $4,500		
Total	**$2,000**	**$2,100**	**$2,000**

CALIFORNIA INDEPENDENT SYSTEM OPERATOR

MARKET DESIGN 2002 PROJECT

COMPREHENSIVE DESIGN PROPOSAL

APPENDIX B

BACKGROUND PAPER

COMPARISON OF CAPACITY OBLIGATIONS AND MARKETS

PREPARED BY POWER ECONOMICS, INC.

APRIL 15, 2002

Table of Contents

I. Introduction

This background paper was prepared by Power Economics, Inc. for the California Independent System Operator, to inform and facilitate the effort to develop effective design changes to address the underlying problems that led to the electricity crisis in California. The paper is intended to meet the desire of market participants for a discussion of the lessons learned in other markets regarding the problem of ensuring adequate supply capacity, and the implications of these lessons for the design of a capacity obligation that reflects the unique features of California.

During the conceptual and design stages of electric industry restructuring, many parties believed that short-term energy markets would provide sufficient price signals for efficient investment in generation resources. Some markets were transformed into energy-only markets, while other markets included explicit capacity requirements. In this paper we provide an overview of the experience of markets that have explicit capacity requirements. The paper is divided into three major sections:

1) A summary of lessons learned;

2) An overview of capacity markets internationally; and

3) A review of capacity markets in the Northeast.

II. Lessons Learned

A. Energy-Only Markets Are Unstable

Why is an energy market unstable if left to its own devices when other commodities markets work just fine? An energy market cannot be left to its own devices because, in addition to being inexorably tied to the laws of physics, an energy market is also different from most markets in that acts of consumption and generation produce costs and benefits that accrue to everyone in the system. Any act of consumption decreases system reliability and any act of adding generation increases system reliability. Economists call these costs and benefits externalities. Externalities are phenomena that a competitive market cannot, by itself, handle. If ignored, the effect can be market failure of the type that has occurred in California. An ACAP, RO, or other type of reliability payment is an attempt to solve this problem of external costs and benefits by internalizing them, as is explained below.

In the absence of a reliability price mechanism, the consumption or generation of energy creates external reliability costs and benefits because:

1) Whenever a consumer uses a bit more electricity, doing so reduces the level of reliability throughout the system by some small, but finite amount. This very small cost is imposed on all the system's consumers, not just the particular consumer who increased consumption. The reliability cost is imposed on people who are external to the act of consumption, i.e. it is a classic example of an economic negative externality. And the consumer is not aware of the cost because it is not explicitly included in the price paid for the electric service.

2) Whenever a generator adds a generation plant to the system, doing so increases the level of reliability of the system for everyone. The increase in reliability provides a benefit for everyone on the system even if the plant never runs but only sits—ready to run if called. If the generator is compensated only for the energy value in a competitive energy market, the system, and consequently all its customers, receive a free positive external benefit. The generator has no practical way to charge individual customers for the reliability benefit because the generator cannot supply one customer without supplying all others. Nor can the generator deny the greater reliability to one customer without denying it to all. If the system as a whole does not compensate the generator for supplying the benefit (such as in an energy-only market), then the generator's supply of the increased reliability is an example a positive externality.

In the energy-only market, therefore, the situation is one in which consumers impose a reliability cost without having to pay for it, and generators confer a reliability benefit without being compensated for it. A reliability payment such as an ACAP or RO solves the problem by charging consumers for the reliability cost that they cause and using the funds to compensate the generators for the reliability benefits that they confer. In a system that has the optimal amount of reserves, reliability costs paid by consumers will equal the benefits conferred by the generators and will also equal the cost of an additional generator, and the price of energy and the reliability payment together will be the long-run equilibrium price.[1]

The reliability payment provides a mechanism whereby customers can pay generators for reliability. In the present structure, the generator who provides the reserve margin without running is not usually compensated and will not want to continue providing this benefit; but, by paying a compensatory reliability payment to the generators who do not run, but only stand ready to run, the optimal level of reliability can be maintained. For the generators, providing system reserve margin and reliability will become a worthwhile long-term investment activity. In economist's terms, the reliability payment internalizes the externalities that are now making the market unstable and inefficient.

B. Methods of Paying for Reliability

Reliability payments, including those that work through Capacity markets, share the same basic objective, which is to maintain the reliability of power systems. The North American Electric Reliability Council (NERC) defines two basic aspects of reliability: adequacy and security. Adequacy is a planning concept that refers to the ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of generation and transmission facilities. Security is an operating term that refers to the ability of the bulk power system to withstand sudden disturbances such as electric short circuits or the unanticipated loss of generating and/or transmission capacity. Security, therefore, is concerned with the daily operation of the transmission grid. The criteria supporting the development of most power system capacity requirements and markets are related to longer-term notions of adequacy, as opposed to security concerns.

There are a number of different approaches to designing capacity markets and obligations. The most basic approach, is to translate the required reserve margin into a Load Serving Entity ("LSE") requirement that is then satisfied by either procuring capacity resources or paying a deficiency

[1] One definition of an optimal amount of reserves is when the benefit to consumers from greater reliability equals the cost to generators for supplying additional capacity.

penalty. An alternative approach, used in Finland, is to simply procure capacity necessary to meet the perceived reserve shortfall and then to collect the cost of that capacity from customers. Deregulation in England and Wales initially paid capacity based upon its reliability value. The reliability value was determined by multiplying a reliability index times the value of reliability. As system resources declined relative to load, the payments to capacity providers increased. In recent years, international markets have shown an increasing interest in using options as a vehicle for assuring system reliability.

Product definition is critical to the design of capacity markets. Ultimately, the challenge of market design is to create reliability value in exchange for capacity payments. One way to garner value is to impose requirements that require generators to bid into a power system's various markets. Therefore, if a generator receives a capacity payment, it must offer that capacity into the energy markets. Often, the requirement to offer capacity is independent of the price level at which energy is offered. This lack of a linkage has resulted in generators offering energy at extremely high prices in order to either exercise market power or to participate in other markets. Another way to tie value to payments is to base payments on generator unit availability as opposed to installed nameplate capacity.

Market power is an important issue in all capacity markets. The market monitor in the Pennsylvania-Jersey-Maryland ISO identified the exercise of market power on the part of a market participant. After the PJM ISO recognized the relationship between deficiency payments and the incentive to exercise market power, the Federal Energy Regulatory Commission ("FERC") agreed to modify the terms that allowed generators to share deficiency payments. Prohibiting the sharing of deficiency payments is thought to reduce the incentive to exercise market power. In other markets, such as the New York City installed capacity market, the FERC has recognized the ability of market participants to exercise market power and has responded by capping capacity prices.

The ability of a capacity provider to shift between markets has a significant effect on the ability of a power system to count on capacity reserves. In PJM, where daily switching between markets had been allowed, the market operators found that the supply of capacity followed energy price differentials, creating an unreliable operating regime. The solution was to increase the time horizon of procurement, shifting to seasonal procurement.

The time horizon of procurement will determine to a large extent the ability to exercise market power and also the effectiveness of capacity markets to support investment in new capacity. With the exception of Columbia, it is striking that none of the capacity markets reviewed provide incentives for capacity transactions greater than a year. In other words, none of these markets provide incentives for purchasing capacity requirements in year x for year x+ 2. Options based approaches, such as the Columbian approach, and the proposal for Spain based on the Columbian approach, could promote multi-year forward contracting.

III. Overview of Provisions for Providing Medium- and Longer-term Reserves in Various Countries

The following section provides an overview on the provision of medium-term and longer-term reserves in various countries.

A. Norway

The electricity system in Norway is unusual in that:

1) the system is 99.7% hydro based with significant reservoir capacity. Hydro plant is not retired or mothballed – it tends to be renovated periodically

2) about a third of total consumption is supplied to large energy intensive companies such as Norsk Hydro, which operates aluminum smelters and chemical plant and consumes about 13TWh p.a., Elkem, which smelts non-ferrous metals such as manganese and consumes about 9TWh p.a.; and Norsk Skog, which is a pulp and paper company and consumes about 4TWh p.a. All of these companies can make significant reductions in their load if it is economic for them to so do

When the market was deregulated in 1991, there was a significant surplus for average hydro-years compared with average consumption. Subsequently no new hydro plant has commenced construction because of an environmental block protecting the rivers and no significant refurbishment schemes have been undertaken. There has been a lengthy and inconclusive debate about building Combined Cycle Gas Turbines (CCGTs), which are opposed on grounds of their CO_2 emissions. Now, not only has annual consumption at 120TWh exceeded hydro production, also the maximum demand is near to the peak capacity of the generation resources of 24,000 MW.

In view of its concern about meeting the winter peak demand, as a supplement to the normal energy spot market which is run by NordPool, Statnett runs for the six month winter hydro season a "capacity market" based on uniform price (or SMP) auctions. It runs two quarterly and intervening monthly auctions inviting offers for supply increase or demand side reduction capacity for quantities that it specifies separately for Southern Norway (Omrade A); the Oslo zone (Omrade B); and Northern Norway (Omrade C). It invites offers for periods of a year and for a quarter and for a month. Each winning party is required by the term of the contract to ensure the plant or load is available on the following terms:

1) during the hours 06.00 – 22.00 of working weekdays
2) reserves must be available to run within 15 minutes
3) reserves must be available to run for at least one hour without interruption
4) reserves must be available to run for at least 10 hours per week. During weeks when public holidays fall between Monday and Friday, this requirement will be reduced

When called, the plant or load is additionally paid the price in the regulation (or balancing market) for the volume generated in the case of a generator or foregone in the case of a load. Details of auction results are available on www.statnett.no go to Marked Og Nett go to Effektreserve go to Avtalt Effecktreserve.

In February 2002 it had contracted for 1781 MW of reserve capacity in contracts of different periods, but mainly of one month. The results show for each month for zone by period of contract (1 month, 3 months, 12 months) the quantity of generation, (produksion), the quantity of load reduction accepted (forbruck), and the price in Norwegian Kroner/MW/month (US$ = 8.81NOK).

The paper "Market-based Power Reserves Acquirement: An Approach Implemented in the Norwegian Power System, with Participation from Both Generators and Large Consumers", by Gunnar Nilssen and Bjorn Walther, Statnett presented at a conference on: Methods to secure peak load capacity in deregulated electricity markets, 7-8 June 2001, Grand Hotel Saltsjobaden – Stockholm, Sweden describes the arrangements. A summary of the conference can be found on www.elforsk.marketdesign.net (go to Reports in English.) SINTEF Energy Research, a contract research group supported in part by the electricity companies in Norway, is researching the reliability issue, see www.sefas.no, click English at top right hand corner, go to Projects of, then to Capacity Shortage.

B. Sweden

Sweden deregulated its wholesale market in 1996 and created a joint spot market and futures market with the Norwegian market to create NordPool. In contrast to the Norwegian electricity system, half of the production is nuclear while generally the other half is hydro (there is proportionately less reservoir capacity than in Norway) but it is supplemented by some oil plant for low-water years. Most of the oil plant was mothballed when the market was deregulated because most years there was a surplus of capacity and energy, but as no new plant has been built the surplus has been mopped up, and there is now concern about the adequacy of both capacity and of energy.

In 2000, responding to lobbying from the generators, Svenska Kraftnät, the transmission system operator, ran a tender inviting offers for 1000MW from the mothballed plant for firm availability with dispatch at Svenska Kraftnät's discretion, for a period of three years. The offers were from mothballed oil plant and open cycle GTs. When Svenska Kraftnät dispatches plant, the owner offers into the spot market at a price equal to twice the variable charge it has offered, and returns the excess to Svenska Kraftnät. The net cost of paying for the plant is levied on (most of) the generators and retailers. The process was extended in 2001, at the request of the government, for another 500MW, but this time an effort was made to attract bids from loads which resulted in 200MW.

In November 2001 the government invited Svenska Kraftnät to propose arrangements for ensuring that additional new plant can be provided if necessary. There are two strands to its thinking:

1) an ICAP market such as the PJM operates

2) empowering Svenska Kraftnät to contract for new capacity, and to impose a levy on retailers for the resulting costs.

C. Finland

Finland deregulated its wholesale market in 1995, and joined the NordPool spot market in 1998. The Finnish system is predominantly thermal, with about two fifths of all production from either industrial cogeneration plant or municipal combined heat and power schemes. Since deregulation some new cogeneration plant has been built. Fingrid, the transmission system operator, owns or contracts and controls 600MW of gas turbines which are for back up reserve. Most[2] of their costs are charged as a system service fee included in the general transmission tariff.

The government is proposing to introduce a bill to empower the Civil Emergencies Authority to contract capacity from producers, which will be funded through a levy on electricity consumers.

D. England & Wales

The Pool, which operated from 1990 until the end of March 2001, incorporated a capacity payment for plant that was available to run on a day even if it did not run. The payment was based on: LOLP * Value of lost load. The value of lost load was set at £2000 ($2800)/MWh in 1990 and subsequently indexed by the British equivalent of the CPI and reached about £2850 ($4050)/MWh in 1998.

Although the Pool was open to many criticisms, including the manner in which generators with market power could manipulate the LOLP mechanism, it provided a very successful platform for developing new plant. From 1990 to now, 25.9GW of plant was commissioned of which all except a 1.2GW PWR was market based, and the interconnector with Scotland has been upgraded from 850MW to 2200MW. Despite 12GW of plant being closed and 5GW of plant being mothballed, the plant on the system has increased since 1990 by 9GW to 68GW while demand increased by only 4GW to 54GW and consequently the plant margin has increased to 26% and will increase to 28% by next winter as plant under construction is completed.

[2] The balancing market has two prices – a buy price and a sell price – which generate a small surplus which is used to contribute to the cost of the reserves.

The New Electricity Trading Arrangements (NETA) are based upon the proposition that a uniform price (or SMP) style auction is more subject to manipulation by parties who have market power than is bilateral trading. The core of NETA is the Balancing Mechanism which is operated by the National Grid Company (NGC) in its role as system operator. At "gate closure," which is currently 3½ hours before each ½ hourly settlement period, trading between market participants ceases, and parties can only make offers and bids for incs and decs to NGC for the Balancing Mechanism. The Balancing Mechanism fulfils two roles:

1) it allows NGC to balance the system

2) it settles imbalances between schedules

In order to encourage market participants to submit balanced schedules (which involves bilateral or exchange-based trading), the Balancing Mechanism is purposefully not a market (which would mean that it would have a single clearing price) and it is intended to be an expensive place to be caught in. This objective is achieved by a "dual cash-out mechanism," namely it has a high system-buy-price (SBP) at which parties who are short have to buy and a low system-sell-price (SSP) at which parties who are long sell their surplus power. The limit on the price in the Balancing Mechanism is £99,999/MWh. The effect of this arrangement is that retailers over contract by about an estimated 3% to avoid being caught in the Balance Mechanism and generators likewise **over** sell to avoid the consequences of a generator tripping.

NGC buys 1600MW firm equivalent of standing or back-up reserve that will be available within 20 minutes in an annual auction where successful offers are paid what they bid. NGC requires that the plant is available for 4000 specified hours, and requires offers to be in the form of an availability price of £/MW/hr (£1½/MW/hr or £6/kW is an indicative price) and an exercise price of £/MW/hr running cost for when the plant is called for the Balancing Mechanism – the price has to be less than £200/MW/hr. It contracts about 1000MW of generation plant as a mix of OCGTs and pumped storage, and about 600MW of demand side capability from (e.g.) cement works, paper companies, the water industry, and consumers with standby plant. Details of the auction are on www.nationalgridinfo.co.uk go to Balancing Services Home go to Tenders/Agreements and Market Reports.

The standing reserve auction does not extend to the longer-term requirement for new capacity. A longer-term shortage of generation could occur if there were a reluctance by the generation industry to develop new plant to meet a growth in demand, or older coal plants were phased out as emission limits for SOX and NOX increase -- possibly with the introduction of a system of CO_2 emissions trading. The belief is that the market will provide for the longer term through the incentive the retailers have to avoid being caught short in the Balancing Mechanism.

E. Australia

Australia began as an energy-only electric market and decided that they had to add a reliability component to the market. The National Electricity Market Management Company Limited (NEMMCO) is the system operator for the interconnected network in Australia and is also responsible for operating the real time market. NEMMCO also has the responsibility of running the mechanism called the “reserve trader”. NEMMCO continually monitors and forecasts capacity reserves in a process called the “Projected Assessment of System Adequacy.” If NEMMCO considers that there may be a shortfall in the short term of days or several weeks, then it is empowered to direct generators or network owners who have capacity that is off-line to bring it back into service, and it can direct large customers to load shed. If it predicts that capacity may be short across a summer period (which is the time of peak demand), then it is empowered to invite tenders either from generating units that night not otherwise be available or from loads. This power runs until July 2003, but is likely to be extended. Thus far, with the construction of a reasonable amount of new capacity, NEMMCO has not used the reserve trader power but it has used its power of direction on a number of occasions.

For long-term security of supply, the Australians are relying on very high market prices attracting sufficient peaking capacity. When the national market was opened in December 1998, the market price was capped at Aus$5000/MWh (about US$2632), a figure which is deemed to represent the value of lost load (VoLL). There has been a lengthy process to review the level of VoLL with the National Electricity Code Administrator – the keeper of the market rules – recommending an increase to Aus$20,000/MWh. Recently in a decision that set out the pros and cons of the issues[3], the Australian Competition and Consumer Commission rejected the proposed increase and directed an increase in the price cap to Aus$10,000 (US$5263). The Commission noted that "if VoLL is set too low it may result in insufficient generation capacity being available in periods of excess demand, resulting in involuntary load shedding and serious disruption to the community. For example, if the spot price is capped at too low a level, investment in peaking, standby and other generation plant, and market based network investment (or equivalent demand management techniques) may be less than they would otherwise have been. In addition, existing facilities in each of these categories may be disadvantaged. It was, however, concerned "about the impact of increasing VoLL to $20,000/MWh where generator market power issues are a concern."

The effect of the potential for high prices has been to *reduce* the contract cover that generators are prepared to offer because they are concerned about a plant tripping and being caught short, and on the other hand some retailers have sponsored the development of peaking plant.

F. Colombia and Proposed for Spain

On behalf of the Association of Colombian Generators, Carlos Vasquez, Michel Rivier, and Ignacio Perez-Arriaga of the Instituto de Investigacion Tecnologica in Madrid devised a market approach to long-term security of supply[4]. The basis of the concept is that the system operator buys at auction on behalf of consumers a quantity of "reliability contracts" that is determined by the regulator. The contracts are a combination of a financial call option with a high strike price related to the spot price, coupled with an explicit and high penalty for non-delivery. The contracts run for a least a year, and could be significantly longer. From the perspective of the system operator, the contracts not only cap the price but also ensure the provision of power when it is most needed through the penalty for non-delivery. From the generators' perspective they receive a certain income in place of the volatile income available from price "spikes" above the option price, but have to offset against this

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[3] Determination: Applications for Authorization: VoLL, Capacity Mechanism and Price Floor, 20 December 2000, Australian Competition and Consumer Commission (www.accc.gov.au).

[4] A market approach to long-term security of supply, Carlos Vasquez, Michel Rivier, Ignacio Perez-Arriaga, Instituto de Investigacion Tecnologica, IIT Working paper IIT-00-0078-A, March 2001, submitted to IEEE Transactions of Power Systems.

income the expectation of paying a penalty for non-delivery. Thus in bidding at auction the generator will have to take account of the reliability of its plant or portfolio of plant.

There will be two kinds of generators competing *at the margin* in the reliability market: less reliable plant such as run of river hydro which would expect to incur high penalties, and new entrants with reliable technology who want to smooth part of their revenue and would expect to incur low penalties. If the value of the penalty is increased, then the relative advantage of the new entrants will improve. Thus the penalty can be set so that any unit with expected availability below a threshold (i.e. reliability) will be displaced by a new generator – thus it will be preferable to build new facilities rather than accepting such an unreliable generator.

The mechanism would be implemented as follows:

1) the regulator sets the basic parameters of the strike price(s), the total amount of options to be bought (Q), the value of the penalty (pen), and the time horizon of the auction

2) a generating company can submit any number of bids of pairs of price (p) and quantity (q) to the reliability auction. The quantity in the bid expresses the capacity that the generator is willing to commit through the option, while the price represents the minimum premium fee that the generator is willing to receive for it

3) the auction is uniform price, i.e. bids are stacked by price and the lowest ones are selected until the sum of all the accepted quantities equals Q, and all successful bidders receive the price of the last accepted bid, P

4) a generator with an accepted bid of qMW receives a premium fee of P.q. In return it pays (p-s).q whenever the spot price p exceeds the strike price s, and additionally pays *pen*(q-g) if the spot price is above the strike price and its production g is lower than its committed quantity

The proposed approach avoids one of the fundamental problems with a regulated capacity payment and an "ICAP market" – namely the remuneration a generator receives depends only on the rated characteristics of the equipment, and is rarely related to the actual performance of the generator during the scarcity situations. Hence there are almost no incentives for generators to make operational decisions (reservoir management, maintenance, scheduling, etc.) that improve their availability during the critical periods and increase the reliability of the system as a whole. In contrast this proposed arrangement penalizes non-delivery heavily.

G. Argentina

Argentina has a mixed hydro/thermal system with thermal plant running at the margin and providing security of supply in low-hydro years. Until the recent economic difficulties electricity demand had been growing rapidly. The combined system operator/market operator CAMMESA operates a centralized dispatch system that creates nodal prices. In addition, generators receive two capacity payments known as "PPAD" and "PBAS":

1) PPAD is paid to dispatched capacity and to plant that is available and spinning but not dispatched during weekday non-trough hours. The current value is regulated at $10/MW/hr. PPAD is charged to distributors and large customers on a monthly basis proportional to their consumption in peak and shoulder hours.

2) PBAS pays occasional run plants (e.g. medium efficiency gas steam plant, and, in Comahue, gas turbines) in wet years when they do not run so that they will be available during non-trough hours in extra-dry years. This payment is a guard against the market failing to provide sufficient plant to meet extreme variability of hydro conditions. Currently PBAS is also equal to $10/MW/hr. (No generator receives both PBAD and PBAS in the same hour - one payment is netted against the other). PBAS is charged to distributors and large customers proportional to their maximum demand each month.

In 1997 the capacity payments totaled US$310m. The arrangement was criticized as merely having the effect of generators discounting their bids, and last year the government proposed a bill to remove the capacity payments and to make various other changes to the market. But Parliament rejected the bill.

IV. Market Structure and Rules in the Northeast

The purpose of this section is to compare the market structure and rules of three systems that transformed from tight power pools into markets. The reason for the formation of these pools differs.

The genesis of these pools was either commercial requirements or based upon reliability. The first power pool was the PJM, which was initially formed in 1927 to coordinate the economic utilization of power produced at the Conowingo dam between three utilities. The NEPOOL and the NYPP were both formed in reaction to the 1965 Great Northeastern Blackout. Each of these regions now has centralized, ISO-operated markets for energy and ancillary services. These ISOs are: the NYISO, the New England Independent System Operator ("ISO-NE"), the PJM Interconnection ("PJM").

The origins of the current capacity markets evolved from historic utility practices of planning for adequate installed generation reserves. The development of adequate installed generation reserves, shared jointly among the member utilities, provided cost savings in tight power pools of the east. System adequacy was assessed by each power pool. Utilities were required to maintain a specified installed reserve margin. It was often less expensive to purchase capacity credits from a neighboring utility than to build a small amount of capacity. Utilities began to contract capacity with each other to cover shortfalls or reduce excesses to meet their designated targets. These transactions were structured on a cost basis and often involved a multi-product transaction of both energy and capacity.

Today, LSEs in the Northeast transact for capacity completely separately from the resources that supply energy. Installed capacity has become its own physical commodity with its own unique characteristics and structural provisions for transactions.

A. PJM Interconnection

PJM Interconnection, LLC, became the first operational ISO in the U.S. on January 1, 1998 (see www.pjm.com). Its objectives are to ensure the reliability of the bulk power transmission system and to facilitate an open, competitive wholesale electric market. Today, PJM is the largest centrally dispatched electric power system in North America covering an area of 48,000 square miles with a pooled generating capacity of over 56,000 MW connected by over 8,000 miles of high voltage transmission lines. The region had an unusually high peak load of approximately 51,600 MW in 1999 and annual energy sales in excess of 250 million MWH.

PJM initiated a voluntary, bid-based energy market on April 1, 1997, coincident with the implementation of its Open Access Transmission Tariff. In April 1998, PJM implemented a system of locational marginal cost pricing, over 2,000 bus locations every five minutes. On June 1, 2000 PJM implemented the day-ahead energy market which enables PJM members to submit next day bids until 12:00 noon with a next-day schedule finalized by ISO staff by 4:00 pm.

PJM's capacity market is an extension of the historic obligation of its members to maintain adequate reserves. Prior to 1998, capacity needs and obligations were determined on an annual basis. Penalties for members that were short on capacity reflected the cost of a new combustion turbine constructed in PJM. With retail competition, PJM introduced open markets in capacity credits to enable new entrants an opportunity a way to meet their capacity needs and provide an opportunity to existing utilities to sell capacity that was no longer needed. On October 15, 1998, PJM initiated a monthly capacity market combined with a daily market that allows buyers and sellers of capacity to submit bids and offers electronically.

PJM includes in two reliability regions: PJM East in MAAC (Mid-Atlantic Area Council) and PJM West in ECAR (East Central Area Reliability Council) each with unique capacity obligations and markets. As PJM describes its function, PJM operates a "Capacity Credit Market" that "allows suppliers to offer and buyers to purchase Unforced Capacity Credit in PJM East and Available Capacity Credit in PJM West." The PJM Capacity Credit Market is administered by the Office of the Interconnection in accordance with the principles and procedures specified in the PJM Operating Agreement. The requirements of market participants' duties and responsibilities in the market are developed in the Reliability Assurance Agreement ("RAA").

1. THE PJM RELIABILITY ASSURANCE AGREEMENT

PJM Reliability Assurance Agreement (RAA) is an agreement between load serving entities. The purpose of the agreement is to ensure that adequate capacity resources are planned and available to provide reliable service to load within PJM's control area. The RAA is administered by the Reliability Committee. There are two fundamental aspects of the RAA – defining obligations and the way in which entities within the ISO can fulfill those obligations.

The RAA requires each LSE to "install or contract for Capacity Resources or obtain Capacity Credits providing Unforced Capacity sufficient to satisfy each day its Accounted-For Obligation." RAA § 7.4.. This obligation can be satisfied by: 1) self-supply, (2) bilateral transactions, or (3) Capacity Credits acquired in the PJM Capacity Credit market. LSEs satisfy approximately 95 percent of their capacity obligations through self-supply and bilateral contracts, and the remaining 5 percent is traded on the Capacity Credit market. New LSEs rely more heavily on the market to satisfy their capacity obligations (FERC, June 1 Opinion, pg.).

The current RAA has different requirements for PJM East and PJM West. The PJM East rules require load-serving entities to arrange for capacity only on a daily basis (plus an accounting for seasonal maintenance needs).

The PJM West has a Daily Available Capacity Obligation and a seasonal ICAP obligation. The daily obligation is 106% of daily forecast peak for the zone and is met with available capacity. The seasonal obligation is met with ICAP and is approximately 110% of the seasonal peak for three seasons. The seasonal obligation provides an insurance against the daily obligation for a month, after which the seasonal obligation can be changed.

2. MEASUREMENT OF CAPACITY

The PJM-ISO was the first power system to measure capacity on an unforced basis, thereby explicitly incorporating unit unavailability into the accounting of generation reserves. The definition of unforced capacity is:

Unforced Capacity = (installed capacity) * (1-$EFOR_d$)

Where $EFOR_d$ is an historic average of the units forced outages adjusted to reflect on and off-peak demand.

The forecast pool reserve requirement (“FPR”) reflects an installed reserve margin (“IRM”) derated by the expected forced outage rates of units in the system. It is stated as:
FPR = (1 + IRM) * (1 - $EFOR_d$).

3. CHANGING STRUCTURE OF THE PJM CAPACITY MARKET

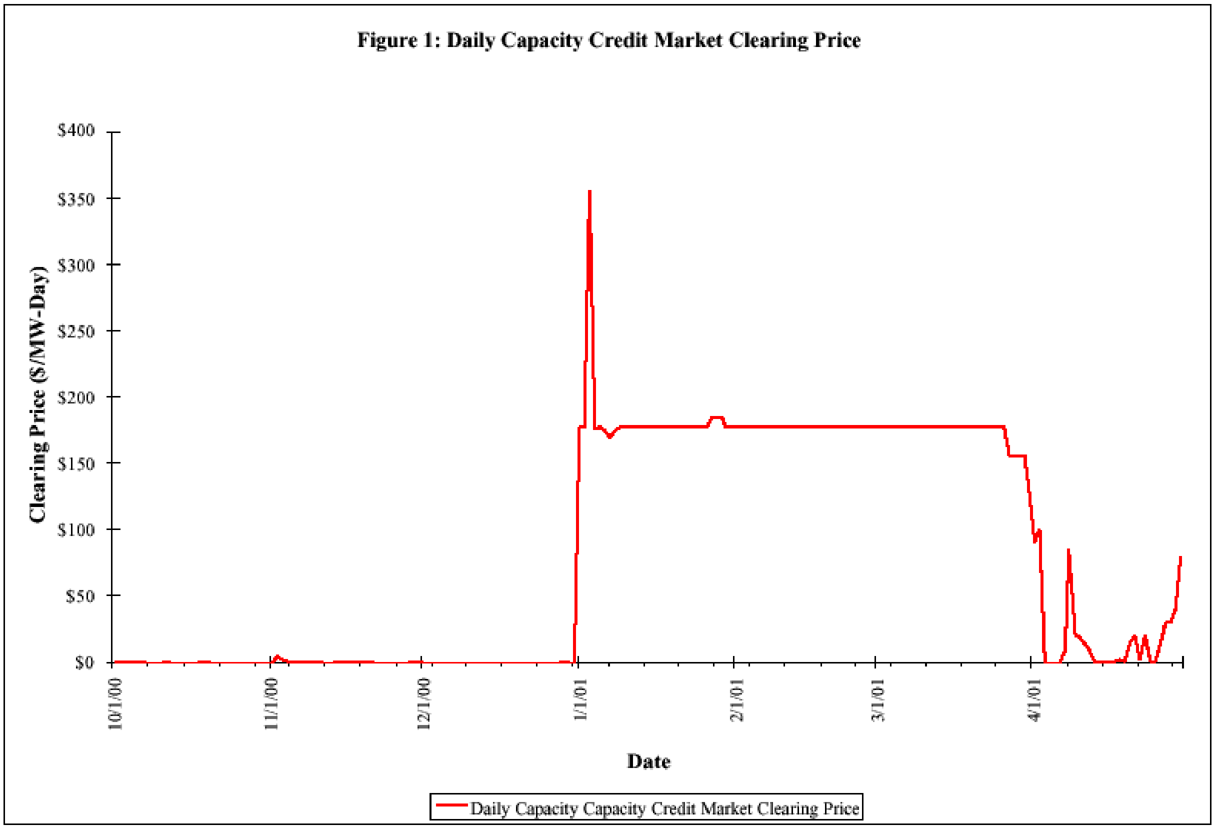
The PJM monitors the behavior of its capacity markets and has used its findings to make modifications to the structure of the market. Two factors have led to the change in capacity market structure:

1. the exercise of market behavior, and

2. unreliability due to capacity resources shifting between PJM and neighboring markets.

During the first quarter of 2001, the PJM daily capacity market was successfully manipulated by a market participant exercising market power. Figure 1 demonstrates the impact of this behavior on market prices. Prices in the PJM daily capacity markets from October 1, 2000 to December 31, 2000 were approximately zero. With tight resource conditions mixed with the behavior of a pivotal supplier, the price increased to about $177 on January 1 and 2, increased further to about $354 for one day, January 3, and then declined to $177 where they remained until late March when the price began to decline further, reaching $0 in early April. Prices reached $354/MW-day on January 3 as a result of the capacity market rules which provide that any deficient party must pay twice the CDR on a day when the overall market is deficient, or short, and which required the entry of mandatory bids at twice the CDR for any deficient party. The overall market was deficient on January 1, 2 and 3.[5]

[5] PJM Interconnection, L.L.C. "Report to the Pennsylvania Public Utilities Commission: Capacity Market Questions," November 2001.



In response to the perceived flaws in the capacity markets, PJM recommended tariff changes to the FERC. On June 1, 2001 the FERC (95 FERC ¶ 61, 330 Docket No. EL01-63-000, Order Accepting Amendment, pg. 5) adopted PJM's proposal to:

1) adjust the time period over which an LSE must commit generation resources to PJM to meet its capacity obligations under the RAA from a daily commitment to a seasonal commitment ranging from three to five months. The three seasonal intervals will be June through September, October through December, and January through May;

2) determine the deficiency charge on an interval basis, so that an entity will be charged a deficiency charge based on the day in which it was most deficient during that season, and the charge will equal that daily amount times the number of days in the season; and

3) require generation owners to commit excess capacity (capacity not already committed to an LSE) to PJM for an entire season, rather than on a daily basis, in order to participate in the distribution of revenues from capacity deficiency charges to LSEs. (Decision, pg. 5)

4. DAILY VERSUS SEASONAL CAPACITY MARKETS

PJM East rules recognized and the FERC concurred that the incentives in the initial design of the RAA were inadequate to assure that load serving entities and generators would have the resources available to provide the PJM energy needs on any given peak day. The core of the problem was identified as the ability of capacity that was bought and sold within the PJM capacity market to be "de-listed" on a daily basis and resold into external markets. Capacity resources switched markets following incentives created by differential in prices between PJM and external systems on a highly volatile basis.

The original RAA rules required that if a LSE was short capacity, it paid a deficiency penalty for the day only. Similarly, generation owners only had to commit capacity to PJM on a daily basis in order to participate in the revenues from capacity deficiency charges to LSEs that are short. These rules provide little incentive for LSEs to arrange for long-term capacity. LSEs often relied on PJM's daily capacity credit market to fulfill their RAA obligations. If capacity was unavailable on a peak day or days, then they paid deficiency charges only for those individual days. Generators similarly had no incentive, beyond the sharing of deficiency penalties, to commit resources to PJM for the entire peak season. They were able to choose on a daily basis whether to commit to PJM or sell their capacity elsewhere, knowing that any individual day the commitment of capacity to PJM entitled them to a share in deficiency revenues.

The remedy for this design flaw as adopted by the FERC was to require LSEs to commit resources for an entire season, rather than on a daily basis, with seasonal rather than daily deficiency penalties. The objective of the change is to enhance the LSEs' incentive to arrange for a long-term and assured supply of capacity that is necessary for reliable PJM operations. Similarly, RAA rules now provide benefits to generators that commit resources for an entire season, not for individual days of their choosing. By limiting deficiency revenue distribution to resources committed only for an entire season, generators with excess capacity will be motivated to commit capacity to PJM East that PJM can rely upon when it is needed.

Prior to the recent changes in PJM, the daily capacity markets implemented to facilitate retail choice and the daily deficiency penalties under the RAA produce flawed incentives. The ability of LSEs to meet their annual load obligations in a daily market and the corresponding ability of generators to make a daily decision about whether to sell their capacity in PJM or "de-list" and sell elsewhere created incentives that diminished the reliability of the PJM East system. When LSEs decided to purchase capacity primarily in the daily capacity markets, daily external market conditions played a significant role in whether the PJM system had adequate resources. If forward prices in the external energy markets made it profitable for generation owners to sell energy to those markets, the generators holding the capacity that would otherwise be offered in the daily PJM capacity markets made it profitable for generation owners to sell energy to those markets, the generators holding the capacity that would otherwise be offered in the daily PJM capacity market had an incentive to de-list the capacity and sell the energy in the external market (not PJM). When this behavior "sold short" the PJM system, individual LSEs ended up short capacity and the system as a whole was short capacity and in jeopardy.

As PJM noted in its FERC filing, the external energy price differential over the internal PJM price did not have to be very large in order for capacity to be diverted away from PJM East. A capacity market price of $160/MWh-day (the stated daily deficiency charge in PJM and, as a result, the effective maximum capacity price in PJM) is equivalent to a net energy price differential of roughly $10/MWh for a 16-hour forward market energy contract.[6] As a result, with a net energy price spread between PJM and external markets of only $10/MWh, generators were motivated to de-list and sell energy externally rather than to sell in the daily PJM capacity market. In other words, the opportunity cost associated with selling capacity into PJM could exceed the maximum possible price for capacity in the PJM daily market. This situation was most likely to prevail on the hottest days when de-listing capacity was most detrimental to PJM reliability.

[6] The modest deficiency charge in PJM has its organs in a regulatory structure where transactions were done on a cost basis to avoid the risk of imprudence findings before a regulatory commission.

Similarly, LSEs that acquired new load obligations through retail choice programs, but do without additional resources, can also end up short. Although the RAA established annual capacity obligations, its deficiency charges were imposed daily. This penalty structure provided LSEs with an incentive to rely upon the daily PJM capacity markets, and a disincentive to obtain resources for the peak season in hopes of being able to purchase capacity in the daily PJM capacity credit markets. The price of capacity scarcity is capped by market rules on deficiency charges. On the days that the LSE is unsuccessful in procuring capacity in the daily markets, it incurs a high deficiency charge. PJM addressed the problems of a daily capacity obligation by eliminating this obligation and creating a seasonal obligation.

B. New York Independent System Operator

The New York Independent System Operator (NYISO) is a non-profit organization formed as part of the restructuring of New York State's electric power industry. The NYISO is responsible for the operation of New York's high-voltage transmission grid and the administration of a wholesale electricity market in which power is purchased and sold on the basis of competitive bidding. The NYISO replaced the New York Power Pool (NYPP), which was formed by the state's largest eight utilities in response to the Great Northeast Blackout of 1965.[7] For over 30 years, the NYPP operated a statewide, centrally dispatched power pool. The NYISO officially assumed control and operation of the state's power grid from the NYPP on December 1, 1999.

The NYISO-controlled grid includes the transmission facilities of the eight utilities that comprised the NYPP. This grid covers an area of 48,000 square miles and includes over 36,000 MW of installed generating capacity. The region's peak load is about 30,000 MW and its annual energy consumption exceeded 155 million megawatt-hours MWH in 1999.

A competitive wholesale market for the sale and purchase of electricity in New York was launched by the NYISO on November 18, 1999. The NYISO operates a day-ahead, an hour-ahead, and a real-time energy market.

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[7] For details and discussion of this blackout see the Blackout History Project (http://chnm.gmu.edu/blackout/home.html).

APPENDIX B

The NYISO has an installed capacity reserve margin requirement for the New York Control Area based on the annual peak and a reserve margin. This statewide reserve margin is now set by the New York State Reliability Council ("NYSRC"). Prior to restructuring the New York Power Pool was responsible for setting a statewide installed capacity requirement (the requirement was established in the mid-1960s). After restructuring the responsibility for setting the statewide installed capacity requirement was transferred to the NYSRC, and the responsibility for defining an installed capacity requirement for LSEs as well as establishing locational reserve margins was assigned to the NYISO. The current level of required installed for the state is 18%.

The NYISO initially created a capacity market that required installed capacity on a capability period basis. The NYISO has made two major changes from the original market design. These are to follow PJM's use of unforced capacity and to facilitate monthly capacity transactions.

The statewide installed reserve requirement is first calculated based upon installed generation capacity and then is translated into unforced capacity. The LSE's requirement is then expressed in terms of Unforced Capacity (UCAP) by dividing the ICAP requirement by one minus the forced outage rate for the district. UCAP, as used in New York, explicitly accounts for unit availability. UCAP derates the amount of ICAP a given resource would be authorized to supply by adjusting the dependable maximum net capability (DMNC), by its equivalent demand forced outage rate (EFOR-D). Each resource's EFOR-D is determined using NERC Generation Availability Data System (GADS) data, or for non-generation resources, equivalent GADS data. Table 1 demonstrates how the installed reserve requirement of 118% are translated into a UCAP requirement of 106.58%.. UCAP requirement for the 2002 forecast peak demand is the most recent EFOR-D.

Table 1. Statewide ICAP and UCAP Requirement (Illustrative)
NY Control Area ICAP Requirement: 118% of forecast peak NYCA ICAP Requirement (2002) = 1.18 x 30,475 MW Reduced by 435 MW to account for Rockland Electric Company load moving to PJM. UCAP Calculation = 30, 475*118%* (1-NYCA EFOR) NYCA EFOR = 9.68% 1- NYCA EFOR = 90.32%

NYCA UCAP Requirement	= 106.58% * 30.475.5
	= 32,479.5 MW

The NY capacity market is split regionally, with New York City comprising its own reliability area. Due to its nature as a load pocket, the price that certain generators can receive for UCAP is capped. When these generators offer to sell UCAP, they receive the lesser of their FERC-approved cost-based price or the market price. During the transition to competition, Con Edison , the utility that provides service to New York City, established a regional reliability rule that 80% of the capacity requirements to support load in New York City would be required to be located within the City. The basis of the 80% rule was an analysis using a multi-area reliability model of the requirements to maintain the NERC LOLP reliability target.8 The regional nature of the capacity requirements was adopted by the NYSCRC. The NYISO performs periodic evaluations of the appropriate level of in-city capacity .9 The translation of the 80% installed reserve into a specific UCAP requirement is demonstrated in Table 2.

Table 2. NY City Capacity Requirements (Illustrative)

NYC ICAP requirement is 80% of peak load

NYC UCAP requirement is the NYC peak load * (80% * (1- NYC EFOR))

NYC EFOR =	10.67%
1-NYC EFOR =	89.33%
NYC Peak Load =	10,665
NYC UCAP =	7621.6

One important feature of the transition to an in-city capacity requirement is the dichotomy between in-city customers served by Con Edison at the time of divestiture and the New York Power Authority's (NYPA) public customers. There are a number of large customers in New York City, such as the City itself, the Metropolitan Transportation Authority (bridges, subways) and the Port Authority

[8] Stone & Webster Management Consultants, Inc. "In-City Capacity Requirements Study," November, 1996.

[9] The most recent "Locational Installed Capacity Study," can be found at "http://www.nyiso.com/markets/icapinfo.html" that was completed on February 28, 2002.

(port facilities and airports) that are served by the NYPA. NYPA and its customers were exempt from in-City capacity requirements and will incur the obligation to obtain reserves in 2002.

Beginning with the 2001-2002 winter capability period, the NY capacity market moved from a 6 month to a one month obligation procurement period. However, the NYISO still holds a six-month "strip" auction for ICAP credits, and then monthly auctions to settle load shifts and deficiencies. The maximum deficiency rate is $13.67 per kilowatt-month in the New York City zone, $12.33 in Long Island and $10.50 elsewhere in the State.

NY has also developed a number of programs to encourage load to curtail at times when available generation is close to demand levels. At least one of these programs pays load as if it were a capacity supplier as well.

C. New England

1. ISO – New England Background

ISO New England Inc. was established as a non-profit, private corporation on July 1, 1997, following its approval by the FERC. For 27 years prior to the formation of the ISO-NE, the New England Power Pool ("NEPOOL"), a voluntary association of New England utilities, operated the region's bulk power generating and transmission facilities.

NEPOOL continues to exist as an entity representing companies that participate in the wholesale electricity marketplace. ISO-NE has a services contract with NEPOOL to operate the bulk power system and administer the wholesale marketplace. ISO-NE serves an area of approximately 66,000 square miles. The bulk power grid managed by ISO-NE has over 7,000 miles of transmission lines and more than 330 generating units. The region has about 25,000 MW of installed generating capacity, and had a peak demand of 22,544 MW and net load of just under 122 million MWh in 1999.

On April 1, 1998, ISO-NE initiated a market for ICAP. A little over a year later, on May 1, 1999, ISO-NE began to administer a wholesale marketplace for six additional products. These six products were energy, automatic generation control, ten-minute spinning reserve, ten-minute non-spinning reserve, thirty minute operating reserve, and operable capacity. All products are bought and sold daily, by the hour, with the exception of installed capacity, which is bid on a monthly basis. Offers by market participants are submitted by noon the day before dispatch. ISO New England notifies generators whether or not they will be selected to run the next day by 5:00 p.m.

2. ISO NEW ENGLAND CAPACITY REQUIREMENT

NEPOOL uses its installed capability requirement (ICAP) to ensure the reliability of electricity supply in the region. ICAP is intended to reward generators for supplying capacity, and pass on the cost of developing generating resources to customers. The requirement calculation begins with a determination of the gross installed capability needed to meet load within the region, known as the "Objective Capability," calculated monthly (http://www.iso-ne.com/mrp/MRP-11_Installed_Capability_Market/). Each customer's ICAP responsibility is determined by "the allocation of Objective Capability to an individual Participant for a particular month ("Installed Capability Responsibility") and is based on the ratio of that Participant's prior month's peak load adjusted for load shifts and contract changes, plus the sum of the Participant's actual or potential load reduction resulting from its NEPOOL Interruptible and Dispatchable Loads ("D_p"), to the entire pool's prior month peak load plus the aggregate of the actual or potential load reduction resulting from all Participants' NEPOOL Interruptible and Dispatchable Loads ("D")."

For a generator to establish or increase capability, a "Claimed Capability Audit" (CCA) must be conducted that supports the claimed capability value. The CCA can be demonstrated through normal operation or through testing of units. Claimed capability are derated due to failure of a unit to demonstrate claimed capability during a CCA. Such de-rating is referred to as a "CCA Derating" and will result in a reduction of the seasonal claimed capability (SCC) for the generating unit. Adjustments to SCC are allowed an ex-post basis. A resource that exceeds its direct availability level receives a proportionate percentage increase in capacity equal to the percentage in excess of target. Similarly, a resource that falls below its target availability level receives a proportionate percentage decrease in capacity equal to the percentage below the target.

NEPOOL also operated an operating capability market. This was a daily market designed to meet operating reserves. Because the market was redundant with ancillary services such as ten-minute spinning reserve and ten-minute non-spinning reserve, the market clearing price for operating capability for the majority of days was zero. The operating capability market was also subject to gaming. NEPOOL has since eliminated a daily capacity market.

3. THE NEW ENGLAND CAPACITY CREDIT MARKET

There are two means for participants to satisfy their seasonal capability responsibility: self-supply or bilateral transactions. The ISO-NE had operated a monthly ICAP market, but it was discontinued because of gaming. LSEs that do not meet the requirements pay at the deficiency rate of $4.87 per kilowatt-month.

D. Analysis of Similarities and Differences Among Markets

Appendix 1 provides a detailed comparison of the rules governing requirements and the procurement of capacity/reserves. Since ICAP markets and requirements are the focus of this study, they receive the most attention in Table 1.

1. SIMILARITIES

The NE ISOs that impose planning or installed capacity reserve requirements on LSEs all base their requirement on essentially the same underlying target level of reliability. This target, or standard, requires that there be no more than one involuntary loss of load event caused by a failure of the bulk power system over a ten-year period. Reliability criteria and standards have been established by the Regional Councils of the North American Electric Reliability Council (“NERC"), which like NEPOOL and NYPP were formed in response to the 1965 Great Northeastern Blackout.

The qualification of external resources as ICAP follow the same criteria for the Northeast ISOs. First, the external units or source of supply must be certified as an installed capacity resource committed to an ISO members supply portfolio. There are limitations on the amount of external capacity that can be used against capacity obligations, and the external resource must also obtain firm transmission for delivery of energy to an external ISO interface and then firm transmission into the ISO. Capacity must be delivered to an LSE to meet its capacity obligation and cannot be held by external market traders for the purpose of speculation. The committed resource(s) must provide letters of insurance against recall.

One factor that affects the reliability value of capacity in the three NE ISOs is the treatment of transmission and generation outages. No transmission owner in any of these regions can take a line or other transmission facility out of service without the approval of the ISO. In New York, all ICAP providers must submit their maintenance schedules to the NYISO. All generators located in the CAISO, or ISO-NE are required to submit their planned outages to the ISO. PJM does not require generators to submit maintenance schedules, but does require notification of planned outages at least 30 days in advance plus provision for maintenance reserve.

Most ISOs require generators to verify the maximum seasonal output of their units. Such verification usually requires either a test or recent historical production data showing that the unit can achieve the claimed level of output. Testing generally must be done according to procedures developed and approved by the respective ISO.

2. DIFFERENCES

Currently, PJM's and NYISO's ICAP requirements are similar. Both, for example, set total ICAP requirements on the basis of load projected over a one-year planning period and both set an individual LSE's ICAP requirement on the basis of the LSE's annual peak load. Thus, while the NYISO now has a six-month and a one-month procurement period for ICAP, an LSE would still be required to purchase enough ICAP to serve its portion of the annual peak load, rather than its monthly peak load. The NYISO's shortened procurement period does not, in other words, affect an LSE's ICAP obligation or the way in which it is calculated. PJM sets the LSE's capacity requirement on an annual basis with procurement now on a seasonal basis. PJM monitors its markets on an ongoing basis to determine the amount of resources available and the extent to which total resource availability is consistent with the aggregate ICAP identified in the plans of all LSEs.

PJM and the NYISO treat external system sales differently. Both ISOs have economic incentives for commitment of "capacity credit" resources to the Control Area (i.e., it is economically unadvisable to schedule a unit out for an external system sale), although provisions exist for external system sales. For PJM, a capacity committed resource will offer a price to the ISO for dispatch. If that offer is not accepted by PJM scheduling, then the resource is permitted to operate for external system sales. Because resources have the ability to set the offer price, a sufficiently high offer price almost ensures that the resource will not be accepted by PJM scheduling and will be available for external system sale, subject to recall by PJM. NYISO permits the same freedom for generators to set their offer price, but rejection of an offer does not have bearing on one's ability to conduct external system sales. External system sales occur through paying the market clearing locational marginal price (LMP) at the external interface bus.

The ISO-NE's ICAP market is different from New York's and PJM's in that it is essentially an after-the-fact accounting mechanism that determines whether an individual LSE had a sufficient amount of installed capacity during any given hour. The ICAP requirement for each LSE is set after-the-fact by the ISO-NE on a monthly basis. An LSE is considered to be deficient if in any hour of a particular month its actual ICAP is less than its installed capability responsibility for that month. The ISO-NE does not, however, set a prospective ICAP requirement based on load forecasts and do not require LSEs to demonstrate sufficient capacity, to meet forecast needs.

E. Comparison of Northeastern Prices

Current and historical average capacity prices for eastern ISOs are shown in Table 1 in units of $/KW-YR.[10] With the exclusion of New York City, capacity prices for eastern ISOs average about $20/KW-YR and range from a low of $10.2/KW-YR to a high of $36.9/KW-YR. New York City capacity prices average slightly over $100/KW-YR and remain a factor of five greater than neighboring capacity markets because of the City's unique locational constraints.

[10] Conversion of monthly capacity prices for New England and New York to annual capacity prices is the product of 12 times the monthly capacity price. Conversion of daily capacity prices in units of $/MW-day to annual capacity prices is the product of the daily capacity price times 365 divided by 1000.

Table 1. Current and Historical Capacity Prices

Market	Year	Ave. Price $/KW-YR*
NY Rest of State	2002/2003 Winter	$10.8
NY Rest of State	2002 Summer	$21.0
NY Rest of State	2001/2002 Winter	$24.0
NY Rest of State	2001 Summer	$22.8
NY Rest of State	2000/2001 Winter	$12.5
NY City	2001/2002 Winter	$112.8
NY City	2001 Summer	$105.0
NY City	2000/2001 Winter	$105.0
PJM E	2003	$11.7
PJM E	2002	$12.5
PJM E	2001	$36.9
PJM E	2000	$19.4
PJM E	1999	$16.8
PJM E	1998	$28.1
NEPOOL	2003	$10.2
NEPOOL	May-Dec 2002	$12.0

*Data obtained from TFS Brokers, NY-ISO and PJM ISO.

Appendix 1:Comparison of ISO Structures

	New York Independent System Operator (NYISO) ***[1]***	**The PJM Interconnection (PJM)** ***[2]***	**New England Independent System Operator (ISO-NE)** ***[3]***
[A] **Planning Period**	The NYISO establishes annual installed capacity (ICAP) requirements for each Transmission District. These requirements are effective from May 1 through April 30, which is known as the Capability Year.	The planning period is defined as the twelve months beginning June 1 and ending the following May 31. This period may be modified subject to the approval of the Reliability Committee.	Two periods exist in which the ISO-NE evaluates ICAP resources. The first is the Summer period which runs from June 1 - Sept. 30, and the second is the winter period which runs from Oct. I - May 31.
[B] **Procurement Period**	Currently, Load Serving Entities (LSEs) have six-month procurement periods; one starts on May 1, and the second starts November 1. NYISO is proposing to require LSEs to procure installed capacity on a monthly basis.	Load serving entities (LSEs) must submit a plan for fulfilling their Forecast Obligation (installed capacity requirement) for each planning period. The Forecast Obligation is adjusted for differences between forecast and actual load and generation availability to derive the Accounted-For Obligation. The latter is calculated on a daily basis and is used to determine if an LSE is deficient.	There is no procurement period. ISO-NE conducts an after-the-fact review, on a monthly basis, to determine whether each LSE had a sufficient amount of installed capacity.
[C] **Load and Capacity Data and Forecast Requirements**	Each transmission owner will submit a weather-adjusted annual peak load forecast for its transmission district for review by the NYISO. Each transmission owner will also submit aggregate peak load data, coincident with the transmission district peak, for each LSE active in its transmission district. All submissions are currently for the planning period.	For each planning period, LSEs submit seasonal peak load forecasts, forecast averages of 52 weekly peaks, an active load management forecast, and generation resource estimates. Finally, the forecast pool reserve requirement is calculated as the planning period peak + the PJM reserve margin.	Participants must submit monthly load data if they serve customer load (including interruptible load), or are assigned a portion of losses associated with pool transmission facilities or certain interties.

[D] **Determinants of Planning Reserve Requirement**	The New York Control Area (NYCA) installed capacity requirement is derived from the NYCA Installed Reserve Margin, which is set by the New York State Reliability Council (NYSRC) to meet a once-in-ten-years reliability criteria, and the annual NYCA peak load forecast, which is calculated by the NYISO by applying regional growth factors to the previous year's peak load.	The planning reserve requirement is determined by (a) the industry standards and guidelines established by the North American Electric Reliability Council (NERC) and the Mid-Atlantic Area Council (MAAC), and (b) an annual reliability analysis performed by PJM. The annual reliability analysis uses the one loss-of-load event in ten years standard mandated by MAAC as a base assumption.	The reliability requirements are determined by the Participants' Committee (formerly a committee of executives that has discretion over budgetary and planning matters). This committee is required to establish guidelines that are consistent with NPCC and NERC standards (i.e., one loss-of-load event every ten years.)	N
[E] **Calculation of Planning Reserve Requirement**	An installed capacity requirement is calculated for the NYCA, which is the product of the forecast NYCA peak load and the NYSRC installed capacity requirement. The installed capacity requirement for each Transmission District is the product of the NYCA installed capacity requirement and the ratio of the District's forecast peak load to the sum of the forecast peak loads for all Districts. The ICAP requirement for each LSE is calculated separately for each Transmission District in which it serves load, and is based on the LSE's contribution to each Transmission District's forecast peak.	Each LSE's individual forecast obligation is calculated as a function of the LSE's expected planning period peak, the PJM reserve margin, the LSE's forced outage rate, an adjustment for large units, and the LSE's load drop adjustment, which accounts for differences in the LSE's and pool's load shape. The sum of the LSEs' individual forecast obligations equals the forecast pool reserve requirement.	The monthly ICAP Requirement is determined by a formula which incorporates the following factors: the participants' share of the total monthly peak; the participants' purchase of interruptible load; NEPOOL's objective capability [i.e., the minimum installed capability level that will meet reliability requirements]; and, various measures of outage requirements.	N

[F] Capacity Procurement	LSEs can purchase ICAP through NYISO administered Installed Capacity auctions (subject to Federal Energy Regulatory Commission (FERC) approval of the NYISO"s Stage I auction design), or can procure ICAP through bilateral transactions.	Each LSE can meet its share of the PJM control area generating capacity requirement through generation and capacity that has been bid into the spot market, generation that is self-scheduled, and bilateral transaction purchases from external control areas. LSEs also can purchase capacity credits to meet all or part of their Accounted-For-Obligation through the PJM Capacity Credit Markets.	There are a number of types of bilateral contracts through which ICAP is procured, including external and internal Unit and System Contracts. [Then] a participant's Installed Capacity excess or deficiency is calculated by subtracting its monthly Settlement Obligation from its monthly Settlement Resources.

[G] **Requirement for ICAP Resources to Bid into Energy Market**	Unless an ICAP resource is unavailable due to maintenance, forced outage, or temperature de-rating, it must either be scheduled in day-ahead bilateral transactions to serve load in the NYCA or bid into the day-ahead energy market. ICAP resources also have the option of bidding into the ancillary services market.	Generators that are Capacity Resources shall submit offers into the day-ahead market, unless they are unavailable due to forced, planned, or maintenance outages. Need to add penalty structure.	Generators that are Capacity Resources shall submit offers into the day-ahead market, unless they are unavailable due to forced, planned, or maintenance outages.

[H] **Method for Assessing Deficiency Charges for ICAP Obligations**	LSEs shall pay Locational Capacity Deficiency penalties, which are calculated as three times the localized, levelized, embedded cost of a GT. An ICAP supplier that fails to comply with the bidding, scheduling, and notification requirements during an hour in which NYISO recalls its energy may be subject to an additional penalty equal to the product of the number of MWs that were not scheduled and the applicable real-time LBMP.	LSEs are required to pay deficiency penalties, which are calculated as the annual carrying charges for a new combustion turbine, divided by a factor of (I - average EFOR).	If an LSE's minimum monthly installed capability during a month is less than its installed capability responsibility, the LSE is deemed to purchase an amount of kW equal to its deficiency through NEPOOL's ICAP market. The deficiency charge is $105/kw-yr. Such kW will be purchased at the installed capability clearing price for the month. Need to verify deficiency charge.

California Independent System Operator

Market Design 2002 Project

Comprehensive Design Proposal

Appendix C

Stakeholder Comments on April 3, 2002 Draft

and ISO Responses

April 29, 2002

Market Design 2002

Appendix C

Stakeholders' Written Comments Submitted by April 11 in Response to April 3 Draft Comprehensive Design, and ISO Responses

NOTE: The ISO did receive some additional comments after the April 11 deadline that may not be fully addressed in this document. The ISO will review these comments and will take them into consideration as we develop tariff language over the coming weeks to file at FERC in mid June.

1 General Comments on Market Design 2002 (MD02)

Overall Process and Time Line. Stakeholders continue to voice serious opposition to the MD02 schedule as unreasonable and as offering insufficient time for review, comment and dialogue (CCSF, Palo Alto, SCE, SVP) and the ISO provided insufficient detail and analysis (Palo Alto) although there was some recognition that deadlines were the result of FERC directives.

ISO Response: The ISO agrees that filing deadlines imposed by FERC directives do not provide sufficient time for an ideal stakeholder process and has repeatedly sought extensions to the May 1 filing deadline and the scheduled expiration of West-wide market power mitigation on September 30, 2002. Stakeholders have responded to these tight deadlines with extreme professionalism and dedication, efforts that the ISO appreciates greatly. The ISO will maintain an active dialogue with Stakeholders to the extent possible within whatever deadlines may be applicable from time to time.

Changes from 2000 CMR Project. MD02 is a fundamental change in policy, embracing a theoretical design that the ISO rejected in the 2000 Congestion Management Reform process with insufficient analytical basis for overcoming earlier objections to the adoption of a nodal pricing model (CCSF).

ISO Response: The MD02 proposal is an extension and evolution of the CMR design, one which reflects more effective enhancements to the ISO's core functions. In particular, the CMR proposal to resolve forward congestion using a network model based on a small number of Locational Pricing Areas (LPAs) was determined in the course of the MD02 project to be unworkable in certain areas of the grid. Moreover, even if it were possible to use the LPA approach for congestion management, that approach would not reduce any of the complexities that arise in connection with the MD02 approach (LMP), such as reallocation of local costs and redesign of FTRs. In addition, the LPA approach perpetuates the difficult problem of establishing workable criteria and procedures for creating new zones. Finally, the ISO believes that it is important to reflect the FERC's Standardized Market Design (SMD), which includes LMP, in its revised market design proposal. We will continue to work with stakeholders to provide analytical justifications for the recommended designs.

Consistency with SMD. Some stakeholders (CCSF) commented that the ISO should defer a new design and/or seek continuation of FERC's June 19, 2001 market mitigation order (CCSF, PG&E), until FERC fully completes its Standard Market Design (SMD) model, despite the ISO's efforts to demonstrate the consistency between MD02 and SMD (CCSF).

ISO Response: As noted previously, the ISO has sought an extension of the June 19, 2001 Order, but has not succeeded in receiving an extension. Given that the FERC has directed the ISO to file a revised market design by May 1, the ISO believes it would be unwise not to proceed with developing a revised market consistent with direction it has received to date, recognizing that there could be future revisions to the recommended design.

Mitigation in Non-Competitive Areas. In non-competitive areas it is essential to limit resources to recovery of cost-based prices for energy and capacity in all markets in those areas until supply can be shown to be competitive (CCSF).

ISO Response: The ISO recognizes that local market power is a concern and will need to be mitigated in both the energy market and in the long-term ACAP design. The ISO has proposed very specific mitigation approaches to local market power in the spot energy markets and in the transition to a full ACAP obligation (see p.70).

Simplicity. The ISO will not be more attractive to doing business unless market rules are redesigned to be simpler, more user-friendly, and more transparent (CDWR).

ISO Response: The ISO continues to work toward simplicity within the overall goals of the MD02 project.

Competition and Risk Management. Strategic Energy raised a concern that the proposed design assumes that the competitive suppliers can not (or will not) manage their risk effectively, asserting that the premise of deregulation is that risk is shifted from ratepayers to market participants.

ISO Response: To the contrary, the MD02 design explicitly aims to allocate risks to those parties best able to manage them. For example, the ACAP design assigns the risk of forced outages to ACAP suppliers, rather than spreading the impacts of such outages to the market at large through real time prices. Similarly, the LMP congestion management approach offers far more precise calculation and assignment of congestion risk to users of the grid than is done today under the zonal system.

Strategic further states that the movement of significant volume from the spot market to the bi-lateral market has had a tremendous dampening effect on market volatility.

ISO Response: The ISO agrees with this observation and has developed the MD02 proposal on the presumption that the vast majority of trading in the future market will be bilateral, rather than spot market transactions.

Performance Obligations on Market Participants. The State Interagency Working Group (IWG) strongly recommends the establishment of a specific obligation on load and supply to perform according to their accepted schedules and to comply fully with ISO dispatch instructions. The IWG asserts that such an explicit obligation is needed in addition to the ISO's proposed system of penalties for uninstructed deviations, to make it unequivocal that departures from final schedules and dispatch instructions are violations of the ISO's rules rather than a matter for market participant discretion based on purely business criteria.

ISO Response: The IWG raises an issue that could be addressed on a continuum from weak incentives to harsh penalties. The ISO is considering the options for implementing such an obligation. The ISO believes that this obligation is most appropriately established as an element of a Code of Conduct, i.e., a set of principles and rules the would codify a system of behavioral requirements for all participants in ISO markets and users of the ISO control area. The ISO is currently examining Codes of Conduct used in other markets and exchanges, and engaging in discussions with other ISOs to identify common approaches and principles. The ISO expects to develop a proposed Code of Conduct later this year and will discuss this with market participants as the project progresses. In the meantime, the ISO is reluctant to create a new stand-alone behavioral obligation within the ISO Tariff and outside the context of a more comprehensive Code of Conduct.

2 Available Capacity (ACAP) Obligation on Load Serving Entities

2.1 General Comments

General Support. Some respondents (SCE, Riverside) clearly support the ACAP proposal. Others (PG&E, CCSF, CDWR) rejected the proposal in its current form but did not reject the overall concept of a capacity obligation. Still others appeared to reject an ACAP proposal entirely (Strategic). PG&E and others also questioned whether there would be potential opportunities for entities to exercise market power in the ACAP arena.

ISO Response: The ISO is cognizant of and sensitive to concerns regarding the exercise of market power in the ACAP market. In recognition of these concerns, as stated in the April 19 Final Comprehensive proposal, the ISO proposes to: (1) not make ACAP fully effective until January 2004; (2) phase out existing RMR Generation (Condition 1) until 2006; (3) integrate an aggressive transmission expansion process with (1) above; and (4) aggressively monitor the functioning of the ACAP Obligation and market, require reporting from LSEs, and file regular reports and information with FERC. The above measures should collectively reduce the risk of the exercise of market power. First, by extending the implementation of ACAP out into the future (a couple of years), LSEs will be better positioned to negotiate fair ACAP arrangements with suppliers. Furthermore, by phasing RMR out over approximately a four year period, LSEs will be better positioned to negotiate fair contracts with local providers. In addition, by integrating the phase-in of ACAP with a proactive transmission expansion process, the ISO intends to address, to the extent appropriate, the elimination of certain transmission constraints that give rise to RMR requirements and the ability of suppliers to exercise market power. Finally, as the ISO recognized in both its April 3 Draft Comprehensive Design proposal and the April 19 Final Comprehensive proposal, the ACAP obligation will require vigilant oversight from both the ISO and FERC. Therefore, in order to fulfill its obligation to oversee the functioning of this requirement, the ISO will file regular reports at FERC and identify any anomalies.

Creditworthiness. Creditworthiness clearly remains a major concern underlying the entire proposal (PG&E, SCE, CCSF)

ISO Response: The ISO agrees and its proposed ACAP implementation plan should allow sufficient time for all Load Serving Entities (LSEs) to establish creditworthiness. The ISO is cognizant of the fact that a LSE must be creditworthy in order to enter into any ACAP arrangement. As recognized in the ISO Final Comprehensive Design proposal, the ISO recognizes that before the ACAP Obligation can be truly effective, creditworthiness issues must be resolved and the CPUC must finalize its procurement rules. The CPUC anticipates issuing a final order in its procurement rulemaking by October 2002.

Complexity. CCSF noted the complexity of "merging functions now conducted by the regulated utilities, the CPUC, the CEC and other state entities."

ISO Response: The ISO has appropriately structured, and limited, its ACAP proposal to support the ISO's core function (reliable transmission service) and core requirements (operating decisions made in a day-ahead timeframe). Moreover, as noted by the ISO in the April 19 Final Comprehensive Design proposal, it is not the intent of the ISO to duplicate any function already performed by an entity in the California market. In the end, while the ISO believes that it has appropriately structured the ACAP Obligation so as to support its operating requirements, the importance and impact of the ACAP Obligation could easily be diminished if all LSEs forward-contract and schedule such power in a forward-market timeframe. Thus, the ISO believes that it is appropriately in the control of LSEs (and, in part, the CPUC) to what extent they are impacted by the ACAP Obligation. Finally, the ISO recognizes and appreciates that this will be a complex undertaking that requires coordination and commits to working with Stakeholders and affected state agencies to finalize details of the ACAP proposal.

2.2 Justification For an ACAP Requirement

Costs. Smaller entities were concerned about the additional administrative costs that would be incurred as a result of adding this tool (SCWC & CCSF).

ISO Response: The ISO's proposed reporting and data collection requirements are not overly burdensome. The majority of this information has to be produced in any event. Moreover, as the experience of Summer 2000 and Winter 2001 illustrate, the benefits of an effective ACAP Obligation (reliable system operation) are likely to be greater than the administrative burden from complying with the ACAP requirements.

ACAP Resources. SCE supports the ISO's proposal that allows LSEs to use generation, firm energy contracts, and demand response to meet the ISO's capacity obligation. While PG&E questioned how capacity provided by hydro resources and imports would be considered given the changeable availability and environmental limitations of these resources.

ISO Response: The ISO has structured the ACAP requirement to maximize the flexibility which LSEs can comply with the requirement. As stated by SCE, the ISO will permit LSEs to satisfy the monthly ACAP Obligation with a variety of products and from a variety of resources. As noted in the April 19 Final Comprehensive design proposal, the ISO has structured the ACAP proposal to permit LSEs to procure the portfolio of resources that best fits their load requirements. Therefore, LSEs will be able to rely on hydro and other energy limited resources, imports, and any other resource that can be utilized to serve their firm load. Historically, the LSEs had been using a variety of resources to meet planning reserve requirements, including hydro resources. Thus ACAP should not represent a new, unfamiliar requirement on LSEs.

2.3 Dimensions of the ACAP Design

Incentives to Develop Capacity. Many Stakeholders, in the context of ACAP as well as LMP and other MD02 design elements, commented that there are insufficient incentives or requirements in MD02 to develop new capacity and questioned how the ACAP obligation would affect future transmission expansions (CCSF). Strategic noted specifically that money that is collected could be used to build generation outside of California, at California's expense.

ISO Response: First, in response to CCSF's concerns, and as explained earlier, the ISO is committed to pursuing a proactive approach to transmission planning and expansion. The ISO shares CCSF's concerns that the elements of the market design project (LMP, FTRs, etc.) are likely to be insufficient in creating further incentives for grid expansion. Thus, the ISO believes that the MD02 proposal must proceed in parallel with a proactive transmission planning and expansion process. With respect to Strategic's concern, the ACAP obligation should provide a platform for generation investment in California – generation that is committed to serving California load. The ISO recognizes that resources may also be built outside of California. However, it is provided in the ACAP proposal, to the extent that such resources satisfy the applicable ACAP requirements, the resources could still contract to supply ACAP and thereby serve California load.

ACAP Time Line. SCWC asserted that the length of the process and the fact that monthly activities would overlap are overly complex and burdensome. Also, the process begins so far in advance that SCWC would be precluded from making transactions with certain trading partners who limit transactions to one month in duration.

ISO Response: The ISO has structured the ACAP proposal so as to maximize an LSE's flexibility in satisfying the ACAP obligation. Thus, LSEs will be able to procure a portfolio of resources to satisfy the ISO's ACAP Obligation, including long-term and short-term arrangements. There is nothing in the ACAP proposal that would restrict a LSE from procuring one-month, or any other duration, products to satisfy the obligation.

2.4 The Role of the ISO in ACAP

FERC Reports. Some respondents (Strategic, CCSF) were adamant that the ISO should not be involved in this process. Respondents were divided regarding the requirement of submitting reports to FERC. Some stakeholders believe that this will be an important procedure while others (Santa Clara, SVP) believe it should be minimal.

ISO Response: As noted above, the ISO believes that vigilant oversight of the ACAP obligation, and its performance, as well as the functioning of any secondary ACAP market, is imperative. While ultimate oversight of the secondary ACAP market will performed by FERC, the ISO believes that it has an ongoing obligation to oversee and monitor the functioning of this market and to provide regular reports to FERC.

Impacts on State Energy Contracts. CDWR and PG&E questioned how the State's energy contracts would be recognized in ACAP obligations. CDWR also raised the concern that if the ISO is responsible for determining what qualifies as ACAP, it will be difficult to be certain that market participants' long term contracts will qualify as ACAP resources month-ahead. Also, process would impact the negotiations on long-term contracts because the month-ahead process would drive entities' contracting decisions.

ISO Response: The ISO recognizes that existing State energy contracts, as well as future contracts, will be important sources of ACAP capacity and must be given full consideration to the extent that they meet the ACAP criteria. At the April 25, 2002 meeting of the ISO Board of Governors, the Board resolved that "any ACAP give full credit to any contracts endorsed by CERS." The ISO also intends to remain flexible when determining whether and to what extent any other existing contract qualifies for ACAP. In all likelihood these other contracts will have to be reviewed and a determination made on a contract-by-contract basis. On a going-forward basis, the ACAP proposal does specify the requirements of ACAP suppliers and hence LSEs should be able to proceed immediately with procuring ACAP resources that satisfy the ISO's requirements. Finally, as noted above, the monthly ACAP process should not in any way restrict a LSE's ability to procure longer-term ACAP resources (i.e., longer than a month).

Transition Period for ETCs. The transition period for ETC grandfathering of existing supply to prevent market power from becoming an immediate problem is less than two years and Palo Alto believes this is not long enough, particularly in constrained areas. More time is needed to allow for the transmission, generation and demand side alternatives to be developed.

ISO Response: As explained earlier, the ISO proposes that the ACAP obligation not become effective until January 2004 and that RMR be phased out over a longer timeframe – until 2006. As stated in the ISO's proposal, the intent is to integrate, to the extent possible, the ACAP, RMR and transmission planning processes. Moreover, the ISO is committed to a proactive transmission expansion process; a process that will attempt to address the transmission constraints that give rise to the ISO's RMR requirements and the exercise of both system-wide and local market power.

2.5 Annual Planning Process

Ten-Year Plans. Some respondents had concerns about preparing a ten-year plan since this is not part of their current procedures (Strategic, SCWC). SCWC was concerned about the complexity and cost of adding this process. SVP suggests moving the date for submitting a ten-year load and resources forecast to October 1st of each year.

ISO Response: As detailed in the April 19 Final Comprehensive proposal, the ISO is proposing to limit the annual process to that necessary to comply with the WSCC's annual reporting requirements. As explained in the ISO's proposal, the WSCC requires its member systems to submit certain information on an annual basis in order to satisfy NERC's Planning Standards. The required information is based on WSCC's established "Power Supply Assessment Policy". Therefore, in order to ensure compliance with that requirement, the ISO proposes to establish requirements on its participants that conform to the WSCC requirements.

2.6 ACAP's Impact on LSEs

Definition of an LSE. CDWR believes that the definition of Load Serving Entity should be clarified to denote that LSEs sell electric energy to end-use consumers (which would not include CDWR).

ISO Response: The ISO agrees. This appears to be a reasonable criterion.

QF Issues. PG&E questioned how capacity provided under QF procurement contracts and QFs connected at distribution would be applied toward any ACAP requirement. Others suggested that QFs need to be included in the resource calculations, but should be aggregated by resource ID and a monthly availability factor should be applied. (SCE)

ISO Response: The ISO agrees that existing Power Purchase Agreements (PPA) should be counted as ACAP. However, the ISO also agrees that a monthly, or some other period, availability factor should be determined. In the end, the ISO agrees that the ISO should, to the extent possible, honor and recognize as ACAP existing power supply arrangements. As noted above, an appropriate "ACAP equivalence" will have to be determined on a contract-by-contract basis, in consultation with affected LSEs.

Forecasting. Some Stakeholders (CDWR, SVP) stated that the LSE is better suited to make its own forecasts and procurement portfolio design, including consideration of operational constraints, but that they could not make forecasts month-ahead with enough certainty to justify penalties for failing to procure. Others suggested that the forecasts could be gamed. If Direct Access is reinstated, LSEs may have a difficult time projecting their load this way (Strategic). Also, one respondent questioned how LSEs' locational ACAP requirements would be adjusted when Direct Access load for a LSE or UDC changes.

ISO Response: The ISO has structured the ACAP proposal to rely on ISO forecasts together with historical LSE load data. As explained in the April 19 Final Comprehensive Design proposal, this is appropriate in order to simplify the process and to reduce the need for the development of new LSE forecasts and their review and update. With respect to concerns regarding the impact on Direct Access, the ISO recognizes that the movement of and accounting for Direct Access load will have to be addressed. In the future, the ISO may have to develop mechanisms and requirements for tracking Direct Access load and ensuring that such load is accurately reflect in LSE ACAP requirements. Such measures can be developed during the proposed transition period.

Determining Reserve Requirements. CDWR/SWP and others support the use of historical load shape curves in determining how much ACAP is required from an entity, i.e., less ACAP in hours that have less load, and believe that ACAP should not be required in off-peak hours. Strategic suggested that any reserve obligation should only be in peak periods during peak months.

ISO Response: The ISO proposes to assess ACAP against the monthly peak load of an LSE, as measured historically. This requirement will not require that a LSE acquire this amount of ACAP resources for all hours. A LSE's ACAP requirements will only be assessed against those hours with a high probability of being the peak. The ISO believes that this is a reasonable requirement in all months, since the requirement goes towards satisfying the ISO's operating requirements.

Impacts on Small LSEs. SCWC is concerned that the ISO's probability forecast will cause SCWC to significantly over procure resources. Very small LSEs may incur reserve margins and ACAP requirements in kWs, not Mw, but would need to purchase whole Mw to cover reserve shortages. In addition, trading small amounts of power (under 25 MW) causes small LSEs to pay a significant premium for their energy, which is an additional cost disadvantage.

Some respondents believed the proposed overall reserve margin amount to be unclear (Santa Clara, SVP, Strategic). Santa Clara and SVP support the calculation of the Monthly Reserve Margin using a probabilistic approach, capping the MRM at 15 percent.

ISO Response: The ISO can be flexible in accommodating the needs of smaller LSEs by adopting measures such as rounding down the requirement rather than rounding up. A LSE's ACAP requirement will be driven by its historical load, as measured by its contribution to the ISO peak. Thus, the ISO is intending to reduce the risk on LSEs from probability forecasts by using historical loads and by assessing the monthly deficiency charges on an ex post basis. The ISO proposes to establish the MRM off of its established operating requirements (operating and regulation reserve requirements) and adding in a contingency for load forecast error and outages. The ISO believes that an MRM established in this manner will support the ISO's core mission – reliable transmission service – and will also move operating decisions into a forward-market timeframe, further supporting stable operations.

Demand side bids. CDWR/SWP supports use of requiring demand-side bids to meet ACAP obligation if deficient. However, the ISO must have sufficient penalty provisions in place to discourage such loads showing up in real-time. Strategic commented that a residential supplier would have difficulty providing demand-side bids adequate to cover any shortfall.

ISO Response: The ISO believes that it is appropriate to require the submission of demand-side bids in instances where a LSE has failed to procure sufficient ACAP resources. This will provide proper incentives for deficient LSEs to remedy their deficiency in the month of the obligation and will provide further incentives to satisfy the obligation going forward. In addition, such requirement will insulate LSEs that have procured sufficient resources from having to bear the consequence of load curtailment should the ISO be required to do so because of the deficient LSE's inaction. Finally, as noted in the April 19 Final Comprehensive design proposal, the ISO recognizes that the ability to curtail specific loads does not currently exist and that the ISO, and others, will have to develop such mechanisms during the transition period.

Impacts of ACAP on Governmental Entities. PG&E questioned whether ACAP requirements would be applicable to government entities in a manner comparable to investor-owned utilities.

ISO Response: As explained in Section 6 of the April 19 Final Comprehensive Design proposal, the ISO proposes to establish the same ACAP requirement for GEs as that applicable to all other LSEs. Moreover, a GE that operates a MSS must schedule 100% of its forecast load in the DA market.

2.7 ACAP Deliverability

Responsibility for Deliverability. Palo Alto was concerned that holding suppliers responsible for providing replacement resources in the event of a plant outage or derate, other than planned maintenance of an ACAP resource, will increase the overall ACAP obligation, as parties will need to acquire additional resources for this contingency. Instead, they assert that TOs have the obligation to provide grid services, including local reliability services and should bear the costs of ensuring ACAP reliability.

ISO Response: As explained in the ISO's proposal, the ISO does not believe that suppliers will have to, or should, hold capacity in reserve under the ISO's ACAP proposal. As discussed, the proposal allows suppliers to satisfy the ACAP requirement from an alternative resource, even if that resource is already bid into the ISO's Imbalance Market. In addition, such supplier will be insulated from any ACAP penalties to the extent they report the original ACAP resource's outage in a timely manner.

FTR Sufficiency. SCE questioned whether sufficient FTRs could be created to satisfy a deliverability requirement where sufficient transmission does not exist to accommodate the output of all generators in a given area under some conditions. SCE further recommended that deliverability requirements for capacity resources should be satisfied like they are in PJM - through generators acquiring Network Interconnection Service.

ISO Response: The ISO agrees that the number of FTRs available into a given load area may be limited. With respect to the existing RMR areas, the number of FTRs available is likely to be constrained by the operating nomograms in those regions. The ISO will continue to assess this issue during the transition period.

2.8 Impact of ACAP on RMR

One respondent suggested that since all customers pay RMR costs (through the capacity component of distribution rates) Direct Access customers should get credit for a share of RMR capacity through their ESP. PG&E questioned how customers can be assured that they do not pay for capacity two or more times if RMR contracts are in effect simultaneously during any transition or RMR phase out.

Palo Alto does not support transferring RMR contracts to LSEs. Any transition period must be sufficiently long enough to enable transmission, generation and demand side resources to compete to provide needed services. During the interim, it is appropriate to retain cost-based pricing for RMR resources. CCSF believes that a transition period of longer than two years is needed to prevent market power problems inherent in the energy markets.

ISO Response: As stated above, in recognition of market power and equity concerns, the ISO proposes to: 1) not make ACAP fully effective until January 2004; 2) phase out existing RMR Generation (Condition 1) until 2006; 3) integrate an aggressive transmission expansion process with (1) above; and 4) aggressively monitor the functioning of the ACAP Obligation and market, require reporting from LSEs, and file regular reports and information with FERC. In the end, the ISO understands the inter-relationship between ACAP, RMR and transmission planning and is committed to developing an integrated policy that effectively and fairly addresses all three issues.

2.9 Interconnection Requirements for New ACAP Resources

PG&E mentioned that any increase in interconnection costs resulting from this policy will be passed on to consumers and that it is not always cost effective to increase transmission capacity if any deliverability constraints are expected to be small in magnitude and/or short in duration. Strategic questioned imposing any type of rule on interconnection costs in advance of any FERC policy statement, stating that the interconnection requirements for ACAP resources should be no different than the interconnection requirements for any other resource.

ISO Response: As stated in the April 19 Final Comprehensive Design proposal, the ISO will continue to monitor the FERC rulemaking on interconnections. It is not the intent of the ISO to impose unreasonable requirements on ACAP suppliers but merely the minimum requirements necessary to satisfy the ACAP deliverability requirements. Moreover, the ISO is not proposing to require that transmission be built in all cases to eliminate small congestion.

2.10 Determination of LSEs' Locational ACAP Requirements

CDWR opposes treatment of loads meeting ACAP as "must-offer" for use by the ISO for system balancing.

ISO Response: The ISO does not expect Participating Loads to be must-offer into RUC.

SVP supports Option 1 for the approach of scheduling the daily ACAP obligation. Offer LSEs the opportunity to choose the option they prefer and be committed to operating under this selection for a designated period of time, i.e. six months before requesting a change.

If the goal of this program is to ensure reliability in the state, then regional requirements should not play into this mechanism. Regional ACAP requirements won't fix regional reliability problems. (Strategic)

SCE does not support the ISO's proposal to require LSE's to procure ACAP resources based on Local Reliability Areas (LRAs) because it may subject LSEs with load in a given LRA to generator locational market power.

ISO Response: The ISO's proposal is to enable LSEs to satisfy the ACAP Obligation through a number of means, including the development of demand-side resources. These load-based products are proposed to be made available to the ISO as "price-cap bid load" in the ISO's DA market, thus reflecting the fact that they should represent the price at which load is willing to be curtailed (i.e., the price cap can and should represent the value of curtailment to load).

With respect to Strategic's and SCE's concerns, as expressed above, a locational ACAP requirement is appropriate in order to reflect and account for deliverability and is consistent with the ISO's existing practice to procure AS and RMR locationally. As also noted above, the ISO recognizes the market power and equity concerns regarding ACAP and the phase-out of RMR. However, the ISO believes that it has addressed those issues by extending the timeframe for the phase-in of ACAP and the phase-out of RMR and by recognizing and committing to a proactive transmission expansion process.

Impacts on Interconnection Agreements. PG&E is concerned that any future CPUC procurement requirements will not coincide or compliment the locational requirements proposed by the ISO. In addition, PG&E believes that the ACAP requirement should be the same regardless whether the entity takes service directly from the ISO or whether the entity receives service under an existing IA and should not impose additional ACAP margins for GE entities simply because they are served under an existing IA or ETC agreement. (PG&E)

ISO Response: PG&E raises a very good point. Going forward, the ISO will endeavor to align its proposed ACAP Obligation with the procurement rules adopted by the CPUC. In light of the fact that the CPUC intends to conclude its procurement rulemaking proceeding by October 2002 and the ISO does not intend to make ACAP effective until 2004, the ISO believes there is sufficient time to align these measures and requirements. As noted earlier, the ISO proposes to assess whether GEs satisfy the ACAP Obligation.

2.11 Impacts of ACAP on Suppliers

Some stakeholders were concerned that the ISO install adequate tracking so that resources would not be double counted, thus impairing reliability and allowing non-beneficial strategic behavior. Riverside questioned the impacts on LSEs if an ACAP supplier were to reject the ISO's ACAP requirements.

ISO Response: The ISO agrees that adequate measures must be in place to reduce the likelihood of double-counting ACAP resources. The ISO is confident that the information reporting requirements contained in its proposal will provide the ISO with the requisite information to ensure no double counting. With respect to Riverside's concerns, the ISO intends to make its requirements clear in the tariff. Thus all potential ACAP suppliers should be aware of the requirements and can factor the risks/rewards of an ACAP arrangement into their negotiations with LSEs. In the end, ACAP suppliers will measure the risk associated with the ISO's proposed requirements and factor that into their offer price to LSEs. If, on a regular basis, the cost of ACAP is comparatively high compared to other capacity products, the ISO may want to re-evaluate its requirements to better align the ACAP Obligation with the needs of the market, of course constrained by consideration of the ISO's operating requirements. Essentially the ISO is proposing the ACAP to send better signals to both loads and suppliers. Cost for ACAP should be equivalent to cost for installed capacity with consideration for outages. Also, all trading for the monthly ACAP obligation and daily obligation will be allowed. ACAP should result in savings to the market in that it will change behavior with the risk of outages being borne by the suppliers who are those who can best manage the risk. Currently the risk of outages is borne by load who have no appropriate means to manage that risk.

2.12 Validation and Enforcement

ACAP Penalties. The sum of daily penalties should not exceed the amount of a monthly penalty. (SCWC). Stakeholders raised the concern that until there is full competition and more than adequate supply, the penalties will set the ACAP price. Others commented that LSEs should be responsible for any shortfall but that penalties should only be assessed when the LSE fails to meet its ACAP requirement when measured against its actual load. (Santa Clara, SVP and others)

ISO Response: The ACAP proposal is appropriately structured so as to clearly define the consequences of an ACAP deficiency while providing LSEs with the maximum flexibility in addressing any deficiency. While the ISO agrees that the ACAP deficiency charge will serve as a cap (a very high cap) on ACAP, the charge is structured so as to create incentives for LSEs to address any identified deficiency. As explained in the April 19 Final Comprehensive Design proposal, the deficiency charge will be assessed on an ex post basis (actual load) for those that have elected to submit demand-side bids to address a deficiency. Thus, there are means to avoid the deficiency charge, but they come with a risk – load curtailment. The ISO believes this to be an appropriate proposal that both provide incentives for compliance yet clearly identifies the consequence of inaction.

Applicability to QFs. SCE recommended that ACAP penalties not be applicable to QF resources of a LSE's portfolio because QFs are regulatory must-take resources under contracts executed prior to CAISO start-up and the LSE does not have the ability to control the output of a QF generator. (SCE)

ISO Response: As provided in the ISO's April 19 Final Comprehensive Design proposal, supplier performance issues and penalties are best addressed in the contract between the LSE and the supplier. Thus, with respect to QFs, performance issues are best addressed through administration of the existing PPAs. In addition, as noted above, the ISO also recommends that the LSE and ISO develop appropriate, perhaps monthly, availability measures for these resources.

2.13 Options-Based ACAP

Strategic believes that the options based ACAP is a much better design for generation adequacy than is the ISO ACAP model, although it also has some flaws such as an apparent misunderstanding of option pricing. Electricity price volatility and other factors lead to high option premiums. SCE recommends that the ISO start with the PJM capacity obligation model and adjust for California as necessary while Strategic suggests that the ISO consider other capacity models that are in development, including those in Texas and the Northeast. (Strategic)

ISO Response: The ISO has not discarded the options approach as a viable means to achieve its objectives. Certainly, in the long-term, when there is sufficient capacity, the ISO agrees that an options-based approach is attractive. At this juncture, however, and in light of the current supply-demand imbalance, the ISO believes that its proposed approach is reasonable. Moreover, there is nothing that will prevent the ISO from transitioning to an options-based approach in the future. Most importantly, nothing in the ISO's proposal prevents LSEs from pursuing this type arrangement with suppliers now.

The ISO's ACAP proposal is largely consistent with those of the eastern ISOs. New York has gone to an unforced availability called UCAP. PJM is looking to move away from a daily market to a longer-term horizon to avoid market power problems. The ISO is proposing more restrictive availability requirements on ACAP suppliers; restrictions and obligations that require an appropriate amount of risk management by the supplier. Thus the overall risk of outages is being shifted from users to suppliers, while allowing suppliers maximum flexibility in meeting its obligations by trading or purchasing from other suppliers if it faces a shortfall.

3 Forward Congestion Management and Energy Market

General Support. Many stakeholders (SCE, others) have stated support for an integrated day-ahead energy, congestion management, ancillary services and unit commitment market. Stakeholders were divided on the proposed congestion management approach. CCSF and EMMT stated support for a forward congestion management mechanism that adjusts generation and load schedules to clear congestion and facilitate voluntary offers to sell and buy. Conversely, CDWR raised concerns about the ISO's proposal stating that the ISO must consider resources' physical operating constraints in clearing congestion.

ISO Response: The ISO's proposal explicitly accommodates resources' physical constraints by (1) performing multi-hour optimization in the day-ahead market, and (2) providing mechanisms such as the current "contingency dispatch only" flag to limit the dispatch of energy-limited AS providers to contingency conditions.

CCSF opposes trades from mandated ACAP resources. Some Stakeholders (CCSF, PG&E) stated that the forward congestion model must address the "dec game."

ISO Response: The use of LMP in day-ahead congestion management, in combination with bid mitigation for locational needs, explicitly eliminates the dec game by eliminating the distinction between inter-zonal and intra-zonal congestion.

Intra-Zonal Congestion Management. PG&E supports the proposed forward Intra-zonal congestion management based on day-ahead scheduling limits in congested areas. CDWR noted the case outstanding before FERC regarding whether the ISO can charge ETC holders for intra-zonal congestion management or change their schedules (the ISO believes it is permitted to do so). SVP recommends that the ISO needs to offer FTRs that provide the same degree of flexibility ETC holders currently have.

ISO Response: The ISO intends to design enough flexibility into the congestion management approach and the design of FTRs so that it will be feasible for holders of ETC rights to convert their rights to FTRs without adverse impacts in the form of unreasonable operating limitations or financial risks.

CDWR supports the proposal for Locational Market Pricing (LMP) if cost allocation is based upon Local Reliability Areas (LRAs).

ISO Response: In developing this proposal, the ISO considered the alternative of using the approach developed during the ISO's Congestion Management Reform (CMR) effort in year 2000. That proposal called for the creation of 15-20 LPAs, based on LRAs that are managed operationally via operating nomograms. The LPA approach is essentially an extension of the existing zonal approach, but would have a larger number of zones, some of which would be interconnected by parallel paths and loop flows. The

LPA approach could also be seen as Locational Marginal Pricing (LMP) with the locations being LPAs rather than nodes. With the LPA approach, it would still be necessary to eliminate Market Separation and the balanced schedule requirement, since these constraints would inevitably lead to insufficiency of adjustment bids in a looped network model with 15-20 zones or LPAs.

The LPA approach would not solve the fundamental problem of ensuring that forward schedules are fully feasible and that forward allocation and pricing of scarce transmission capacity is fully consistent with real time power flows. It would still retain the distinction between intra-zonal and inter-zonal congestion, and would manage these in two separate steps. Finally, the LPA approach would still require criteria and procedures for creating new zones, which raises both complexity and time lag concerns that can be simply eliminated by implementing the LMP (nodal) approach.

The ISO will allow load to be scheduled and settled on an aggregated basis. In addition, the ISO will allow scheduling coordinators to arrange for new customized load aggregations to simplify the scheduling process when moving to LMP.

<u>Phantom Congestion</u>. SVP disagrees with the ISO that phantom congestion is the byproduct of ETC rights. Instead, SVP suggests that phantom congestion is a byproduct of poor market design.

<u>ISO Response:</u> The ISO respectfully disagrees. Phantom congestion is by definition the result of reserving unscheduled ETC capacity through the running of the day ahead and hour ahead congestion markets. If such capacity were released in the day ahead market there would be no phantom congestion.

One stakeholder commented that local prices are not the only, nor the best signal for building transmission.

<u>ISO Response:</u> FERC noted in its April 10 Options Paper that locational price signals are not sufficient to bring about needed transmission upgrades, and that effective transmission policy is required. The ISO agrees with this observation, and is committed to pursuing an effective transmission planning and upgrade process with renewed vigor.

<u>Transmission Losses</u>. Some Stakeholders (EMMT, others) recommended applying average losses directly to load (rather than the current application of locational loss factors) as being simpler and/or more consistent with the treatment of distribution losses.

<u>ISO Response:</u> The ISO is considering an approach similar to the New York ISO's approach in which marginal prices with and without losses are produced. This determination of losses is consistent with FERC's Standard Market Design. The NYISO approach uses an AC-OPF solution that incorporates the losses into the LMP.

<u>Virtual Bidding</u>. Although it is not part of the ISO's proposal, EMMT recommended that the ISO design its software to accommodate virtual bidding so a market participant can take a position in the Day-Ahead market, relative to anticipated Real Time prices, without entering into inter-SC trades, stating that this tool tends to cause the real time and Day-Ahead prices to converge.

<u>ISO Response:</u> The ISO has considered Virtual Bidding, has looked at how it is implemented in the New York ISO and PJM designs, and agrees that the new market design and associated software should not impede the possibility of incorporating this capability in the future.

Market Time Line. The ISO has considered possible changes to the DA time line, including moving the DA deadlines six hours earlier to accommodate Western energy trading and natural gas nomination deadlines. However, most Stakeholders oppose such a major shift, despite concerns raised by EMMT that the current time line could trigger penalties or a physical shutoff of fuel supply. Settlement timelines could be made more consistent with existing wholesale energy markets, perhaps including monthly settlement of forward market transactions, rather than daily settlement. (Palo Alto). SCE and others have stated that the Hour-Ahead market is not essential, but a mechanism for making schedule adjustments after the close of the day-ahead market is essential.

ISO Response: If financially binding hour-ahead schedule adjustments are necessary, then the ISO must run the integrated congestion management and energy market in the hour ahead; there is no practical simplification.

Phasing of Implementation. Stakeholders' comments varied from recommending that the ISO wait until October 1, 2003 to implement the full energy market design (versus a partial design on April 1, 2003) (EMMT, others) to support for implementation of Intra-zonal Congestion Management implementation in Phase I (PG&E, others).

ISO Response: The ISO believes that there will be immense benefits from implementing the integrated forward markets as early as possible, even without having the full network model (FNM) available at that time. The full scope of the MD02 changes will involve substantial learning by the ISO and the market participants, and the proposed phasing allows everyone to become more comfortable with the operation of the integrated market before the FNM and the new FTR design are implemented. In addition, as an enhancement to the learning process the ISO will be able to run the FNM and generate nodal prices for some period prior to Phase 3 implementation, so that all parties can have several months to observe how the complete MD02 design will operate.

4 Firm Transmission Rights (FTR)

Allocation of FTRs. Stakeholders generally recommended that sufficient FTRs should be allocated to LSEs to ensure LSEs can serve their customers, to meet capacity obligations imposed by FERC or the ISO/RTO, to honor existing QF contracts, and to import their generation resources located outside the ISO control area. Some respondents (CCSF, CDWR/SWP, Palo Alto, SVP) recommended that the FTR allocations be limited to LSEs. Others (Palo Alto) believe that the allocation of FTRs to wholesale customers should be made based on their historical usage of the grid to serve load, not just in proportion to their aggregated load capacity at the corresponding node or hub.

ISO Response: The ISO's proposal is to give priority for FTR allocations to LSEs and to converted ETCs, based on their historic patterns of using the grid. The specifics, the process and the timing for FTR allocations have not been yet determined.

FTR Allocation. If, as proposed, FTRs are sold across congested paths, those FTR rights should be directional, point to point and allocated to the load in the higher priced zone indicated by the direction. (CCSF, SCE)

ISO Response: The ISO proposes to implement a point-to-point FTR model initially, where a "point" may be an individual node or an aggregation of nodes. The methodology for an optimal allocation of FTRs under this approach has been fully developed and is currently in use by other ISOs. The ISO is committed to implementing a more versatile FTR approach (including path-specific rights, and a mixed obligations and options design) to meet the needs of market participants as soon as is technically feasible.

Allocation of FTR Payments. Some stakeholders support allocating FTR auction revenues directly to LSEs or other entities that use transmission or for whom the transmission was constructed. This is consistent with FERC's Standard Market Design and allows such entities to hedge against the costs of purchasing FTRs to serve their loads (CDWR). The revenues should be placed in an escrow account dedicated to transmission upgrades to increase the size of the transmission path to eliminate the congestion (CCSF). Others recommend that primary auction revenues be allocated to the PTO and credited against the transmission revenue requirement for the benefit of all transmission customers.

ISO Response: The ISO proposes to allocate FTRs directly to LSEs and converted ETCs in a way that reflects their actual use of the grid to serve their loads. Any capacity remaining after this allocation would be auctioned. LSEs and holders of converted ETC rights would be allowed to sell some or all of their allocated FTRs in this auction, and would receive appropriate shares of the auction revenues in return. Any remaining auction revenues would be given to PTOs to offset their transmission revenue requirements

Conversion of ETCs to FTRs. Some stakeholders are concerned that FTRs, as envisioned by the ISO, do not offer the same level of transmission service as they currently receive under ETC rights and expect that any replacement transmission service would be at least as robust as ETC rights, e.g., firm physical transmission access and a scheduling timeline that provides greater flexibility than the ISO timeline.

ISO Response: The ISO is committed to implementing an FTR design that allows converted ETCs maximum flexibility to meet their needs, within the limits of technical feasibility and consistent with the important objective of having a single congestion management procedure and timeline that applies to all ISO-controlled transmission. In this regard, the current extended timeline for ETC scheduling dramatically impedes efficient allocation of the grid by creating "phantom congestion." The ISO therefore will strive to develop FTR instruments that enable holders of ETCs to meet their needs with minimal exposure to congestion risks, but will seek to bring all grid users under a common timeline for scheduling and congestion management, consistent with direction FERC has provided in its Standard Market Design Options Paper of April 10. On a related issue, the ISO sells transmission service from transmission capacity made available to it under the Transmission Control Agreement (TCA). Given that a transmission owner could withdraw participation with two years notice under provisions of the TCA, it would appear that the ISO might not be able to honor all FTR commitments over a three-year term. However, if FTRs with a term exceeding two years were sold by the ISO, the FTR product could be structured to terminate early in the event one or more PTOs withdrew from the ISO during the term of the FTR.

CCSF and SVP recommend that any conversion of ETC to FTRs and usage under such FTRs must be seamless to ETC holders.

ISO Response: The ISO recognizes this concern and therefore proposes to make its congestion management and FTR design as flexible as possible to meet the needs of all users of the ISO control area including ETC holders, and to make it attractive for ETC holders to convert their existing rights to FTRs.

FTRs as Options vs. Obligations. Through the MD02 process, most Stakeholders have supported FTRs as options, rather than as obligations.

ISO Response: As noted above, there is a tried and proven algorithm for performing the required simultaneous feasibility assessment for obligations FTRs, but not yet for options or mixed options and obligations. The ISO therefore proposes to begin with the known algorithm and to add additional varieties of FTRs as the required algorithms are perfected.

Some have supported paying usage charges to FTR holders only if they were actually used to schedule or retention of the original design of FTRs.

ISO Response: The current FTR design is insufficient to hedge congestion risk under the proposed LMP congestion management approach. The ISO will continue to explore the possibility of incorporating some path-specific options FTRs (like the current model) into the basic point-to-point obligations model, and will do so when technically feasible. The ISO is not currently considering limiting the payment of usage charges to instances when the FTRs are used to schedule. However, the proposed obligations FTR model does provide strong incentives for FTR holders to schedule in accordance with their FTRs by exposing them to financial risks when they do not schedule.

5 Must Offer Obligation

General Support. Some stakeholders supported continuation of some form of Must Offer obligation (EBMUD, SCE, Sempra, Palo Alto). SCE and Sempra further recommended that Must Offer should apply to all non-hydro generation units that have executed a PGA to bid all available capacity into the ISO's real-time market in all hours and SCE went on to recommend that, for long-start-time units, the must-offer obligation should extend into the day-ahead time frame and be consistent with the ISO's RUC proposal.

ISO Response: Consistent with FERC's June 19, 2001 Order, the Must Offer obligation applies only to unscheduled capacity from non-hydro PGA resources.

Other stakeholders reserved judgment either in general (CMUA) or until the ISO offers a more detailed ACAP proposal (CCSF).

Financial Concerns. IEP questioned whether the must-offer/RUC would interfere with existing commercial arrangements or provide a disincentive for LSEs to procure sufficient resources to meet their needs (including reserves). TANC recommended that the ISO ensure that the costs associated with market power mitigation measures be allocated appropriately to those entities who cause the CAISO to incur the costs.

ISO Response: Self-schedules and bilateral contracts will still be encouraged in the DA market. RUC costs will be borne by LSEs that fail to schedule enough resources day ahead to meet their needs, thereby giving them an incentive to procure sufficient resources ahead of time. The ISO continues to use cost causation as the primary criterion for cost allocation.

Exempted Resources. Many stakeholders recommended that the ISO limit Must Offer obligations, or exempt completely from Must Offer, a variety of resources including:

Energy limited resources, including those such as CTs that may be limited due to permitting constraints. Such units should be required to only offer a limited amount of hours per year (***Calpine***) or exempted entirely (***EMMT, SCE***). If energy limited resources are required to "supply on demand" they must NOT be penalized for failure to deliver nor should any associated positive or negative uninstructed deviations costs from these units be spread to all load (***SCE***).

All hydroelectric PGA resources (with or without storage capabilities) (***CDWR, EBMUD***)

Units that are subject to other laws (*e.g.*, site permits, emission limits, environmental laws) or commitments to purchasers should be exempt from the Must Offer requirement (***CMUA, EMBUD, IEP, SCE***).

Gas-fired resources with pipeline constraints. In some cases, a generating unit which has quick start capability may need to be committed day-ahead, more like a long start time unit, because of the physical limitations imposed by the fuel supply contract and the physical nature of the pipeline. If such units burn un-nominated gas volumes in response to an ISO dispatch order, they may face supply cutoffs in addition to imbalance penalties. (***EMMT***)

Quick start PGA resources (such as CTs) because of their ability to respond in real time, potential undermining of existing bilateral forward arrangements with LSE's and suppliers and the FERC's statement that the day-ahead market should be voluntary. (***GWF Power Systems***)

Units built primarily for retail customers and only on occasion for wholesale sales, except under extreme emergencies (***Redding***).

<u>ISO Response:</u> Due to the short-term nature of the October 1 Design Elements, the ISO's Must Offer obligation is consistent with FERC's June 19, 2001 Order and applicable to all non-hydro PGA resources. As with the existing must-offer obligation, resources that are not available due to outages, have scheduled their energy to a load (which may be outside the ISO Control Area) in the day ahead market, or for which complying with a dispatch instruction would cause them to lose their QF status or violate an environmental permit are deemed to comply with the obligation even if they do not submit their bids.

Under the ISO Proposal, all non-hydro PGA units (including quick-start units), to the extent that they have additional unscheduled capacity, will be required to bid into the Residual Unit Commitment Process.

<u>Basis of Default Bids</u>. Some stakeholders stated their support for the proposed three-part bid (Calpine, Mirant, SCE). However, Calpine and IEP commented that the ISO's continued use of the monthly gas index is not appropriate. Alternatives and enhancements suggested by stakeholders for establishing the index include:

A spot market index for transactions occurring during the time the RUC resource is selected (***Calpine***).

The gas price which is in effect at the time the RUC process designates the resources, for example a day-ahead price index (***IEP***).

The CAISO tariff should clearly define the incremental heat-rate as a curve that represents the first derivative of the equation of the input/output curve (***SCE***).

<u>ISO Response:</u> The ISO believes a monthly gas index is a better measure of a resource owner's gas portfolio cost than a daily gas index. Furthermore, the ISO remains concerned that the daily gas market is not a liquid and competitive market and therefore would not reflect the true opportunity cost of gas.

Due to the short-term nature of the October 1 Design Elements, the ISO's Must Offer obligation proposal, including the utilization of a monthly gas price index, is consistent with FERC's June 19, 2001 Order. The last bullet is, in fact, the definition of the incremental heat-rate curve.

Other stakeholders recommended that default bids:

Include compensation for any penalties incurred, including gas imbalances, emission credits or permitting (***Calpine, IEP***) and all relevant costs, including start-up and no-load costs if not paid separately when unit is dispatched (***IEP***). Have an option to submit an energy-only bid (***Mirant***). If a unit has a DA bilateral schedule, a participant can satisfy the Must Offer obligation by submitting energy-only bids for unloaded capacity; and

Be based on variable cost during periods when locational market power could be exercised (***Palo Alto***). The intent of the Must Offer obligation is to ensure system, not local reliability, needs are met.

ISO Response: The ISO would consider these costs and penalties if they can be validated. The ISO agrees with Mirant's comment: units partially scheduled in the DA and under Must Offer must submit energy-only bids for unloaded capacity. The ISO recognizes that local market power is a concern and will need to be mitigated in the energy market . The ISO has proposed very specific mitigation approaches to local market power in the spot energy markets.

Treatment of Start-Up and Minimum Load Cost. Some stakeholders expressed general support for the proposed treatment of start-up and min-load costs (Calpine) and the "net of market revenue" approach to paying startup and min-load costs and making compensation contingent upon availability and compliance with ISO dispatch instructions (SCE). Others recommended that units be paid start-up and min-load costs if a unit is started at the ISO's request, even if they subsequently become unavailable due to a legitimate plant or system problem (Calpine) and whether or not they are dispatched for energy (because the ISO has effectively purchased capacity) (IEP, SMUD). Partial payment for units that ultimately provide energy may be a middle ground (Mirant).

ISO Response: If not dispatched for energy, units will be paid start-up and minimum load costs. In the ISO's proposed RUC tariff, the ISO has provisions for partial payment of a unit's start-up costs if that unit becomes unavailable during the commitment period.

Transition to Market-Based Bids. EMMT suggested that cost-based start-up and min-load costs are acceptable during initial implementation of MD02, but ultimately, those costs should be market-based. It may be possible to simplify the short-term mechanism, rather than using verified actual costs, by adopting formula-based bid limits.

ISO Response: The ISO believes a cost based approach for start-up and minimum load energy is the appropriate long-term design but energy bids should remain market based (p. 110).

Cost Allocation. CMUA commented that start-up and min-load costs should be allocated to those entities that caused the procurement to ensure that those entities that provided adequate supplies would not bear any RUC costs.

ISO Response: As stated elsewhere, the ISO agrees that cost causation should direct cost allocation.

Validation of Compliance. SCE stated their support for proposed tests and added that the CAISO must have the Tariff authority to audit the physical operating constraints to ensure that bids related to unit operating characteristics reflect physical reality, reject suspect operating constraint bids and replace such bids with either the results of the most recent audit or a proxy based on units with similar design characteristics. Further, it may be appropriate to establish provisions for penalizing excessive deviations from CAISO instructions, including CAISO dispatch instructions issued under a must-offer rule depending on the tolerance band and on the level of the penalties. (SCE)

ISO Response: The ISO agrees that operating constraint bids should reflect physical reality, with appropriate ISO authority to audit such operating characteristics.

Outstanding concerns:

Whether full costs incurred to comply would be recovered under this approach, particularly for the long-lead time units (***IEP***). For short-lead time units (e.g., a peaker), how would validation work ("validate that the resource started and is on-line for the commitment period") when the "commitment period" is defined as the minimum run time? (***IEP***)

How will the Must Offer obligation apply to Energy Limited Resources that opt to participate in the RUC process? (***EBMUD***)

ISO Response: The ISO would consider these costs on long-lead time units to the extent that they can be validated. On short-lead time units, validation would be accomplished via metering and/or telemetry. With the exception of hydroelectric resources, energy limited resources will be subjected to the Must Offer requirement absent a showing that running the unit violates a certificate, would result in criminal violations or penalties, or would result in QF units violating their contracts or losing their QF status. PGA energy limited resources that do not fall under these exemption categories would be considered in the RUC process.

6 Residual Day Ahead Unit Commitment (RUC)

Role of RUC. The RUC, coupled with the must-offer (and the ACAP), seems to (inappropriately) place the ISO in a backstop role to buy energy and capacity for LSEs that have not secured adequate resources on a forward basis (IEP).

ISO Response: As indicated in the design document, the ISO plans to use RUC only to procure energy and capacity necessary to ensure system reliability. The residual unit commitment process is a common tool that is being used in the Eastern ISOs.

CCSF is concerned that, absent approval of Amendment 42, RUC does not address physical withholding, economic withholding or megawatt laundering directly.

ISO Response: The ISO believes the most effective design element for addressing physical withholding and MW laundering is ACAP. Physical withholding is further mitigated through the imposition of uninstructed deviation penalties as proposed in Amendment 42. The ISO intends to refile this aspect of Amendment 42 as part of the May 1 filing. Economic withholding is addressed through the DCBC, AMP, and local market power mitigation. As indicated in the ISO documents released on April 19, 2002, the ISO will be developing a final recommendation on local market power mitigation shortly after the conclusion of the FERC sponsored stakeholder conference on May 10-11, 2002.

RUC and Municipal Utilities. In general, municipal utilities, including Palo Alto and NCPA, support the ISO's proposal to allow them to use their own resources to meet their needs, outside of the RUC process, a provision that is consistent with cost causation principles. However, several representatives of municipal utilities (Palo Alto, NCPA) requested clarification on "establishing resources in advance," specifically whether municipal utilities that are available to meet municipal load under NERC guidelines but cannot be "tagged" from source to sink under ISO timelines would meet this criterion.

ISO Response: NERC tags are used between the control areas making it is easy to identify schedules, at the interties, that will be serving Muni loads. To accommodate the Munis, the ISO is planning on establish a system which will allow Munis to identify their committed resource removing it from the RUC stack.

Load Participation in RUC. Some stakeholders (Palo Alto, NCPA, others) stated their support for allowing load curtailment to participate in the RUC "market."

ISO Response: Section 5.8 presents the ISO's proposal to allow load participation in RUC using three-part, market-based bids, effective 10/1/02. In the long term design, only ACAP resources will be eligible for RUC, but load participation will be eligible to be an ACAP resource.

Use of Three-Part Bids. Most respondents (including SVP, Mirant, SCE) supported three-part (start-up, minimum load, and energy) default bids that are based on units' incremental heat-rate curves (adjusted for monthly gas price index) for day-ahead commitment decisions, including the RUC process.

ISO Response: The ISO is planning to continue with the three-part bids.

Capacity Payment Calculation. Mirant raised a concern that the capacity payment calculation is based on inferred total gross costs of production, rather than on changes in incremental heat rate. In either case, there could be large disparities in payment for equivalent capacity based on arbitrary differences in the slope of the heat rate curve. Mirant suggested that payment based on the cost of newly constructed capacity would be better, although this would create questions regarding the appropriate assumptions to use.

ISO Response: Conceptually, the ISO is proposing to keep the generators committed in the RUC process financially whole; that is, cover their costs.

Option Payments for Interties. BPA stated that "no-load" or option payments for intertie bids into the RUC market would help to compensate for other risks and costs.

ISO Response: After Oct. 1, 2002, it is planned that interties will be allowed to enter energy curve bids, due to the short-term nature of the October 1 design elements.

RUC Procurement Quantity. Mirant supported the adjusted proposal for amounts of RUC that would be acquired because it addresses the tendency to over-commit resources. SCE supported energy procurement being limited to a maximum of 95% of the next day's hourly load forecast and requested that the ISO clarify how RUC energy is "assigned" to SCs with balanced schedules between the day-ahead market and the hour-ahead market.

ISO Response: The current methodology would perform the load forecast in the DA market for the HA and RT markets with an expected load forecast error up to 2 to 3%. The ISO is confident that the 95% limitation will hedge against any over procurement. The proposed RUC tariff language clarifies how RUC costs will be allocated.

Participation in RUC. Some stakeholders commented that imports (Interties) should not receive different treatment, but should compete equally with in-state resources. (IEP, Mirant) This would include offering the same products, using the same three-part bid structure for the same durations and competing based on price (IEP, Mirant).

ISO Response: In the Oct. 1 2002 implementation the Intertie resources that are not visible will be able to submit an energy curve bid. The RUC process will commit resources based on price, due to its cost-minimizing algorithm. Intertie resources that submit just energy bids will have to subsume their start-up and minimum load costs into their energy bids.

In addition, intertie resources do not need to be “visible” for verification (Mirant) and it may be appropriate to permit them to set the MCP, consistent with other markets (IEP).

ISO Response: Resources outside the control area are permitted to bid in using the three part bidding structure if the ISO has telemetry from the resource. The resource will not be able to set the MCP.

The potential that importers could bid against one another for a limited amount of intertie purchases at prices unrelated to those produced by the market as a whole raises questions about the practicality of mixing intertie energy bids with in-state capacity bids (accompanied by minimum load energy) in the RUC market (BPA).

ISO Response: In-state generators and intertie resources will both submit energy bids and the RUC process will commit enough resources to meet expected demand using a cost-minimizing algorithm.

7 Real-Time Economic Dispatch Using Full Network Model

LPA Price Determination. Some stakeholders questioned whether there will continue to be inc and dec prices and how LPA prices would be set in circumstances when there are multiple real-time dispatch solutions within an interval. CCSF and others questioned whether there could be opportunities for non-beneficial strategic behavior as a result of applying LPA-based pricing for uninstructed deviations and locational pricing for instructed deviations or by strategically categorizing load as dispatchable and non-dispatchable to take advantage of differing prices.

> ISO Response: The ISO fully intends to schedule and settle generation and participating loads at the nodal level to ensure feasible forward schedules and correct pricing and allocation of the grid. A single energy bid curve is proposed for all services in all temporal markets. The potential for strategic behavior or gaming is readily eliminated by limiting the ability to switch between nodal and aggregated prices; e.g., a given consumer might have to remain with one pricing mode for a minimum of 6 months or so Demand Scheduling and Settlement

Support for / Opposition to LMP. Some Stakeholders (CDWR) supported the proposal for LMP if cost allocation is based upon Local Reliability Areas while CCSF opposes moving to LMP now while others were concerned that allocating costs based on LPAs would create an incentive for areas with costs below those of the LPA to municipalize.

> ISO Response: If LMPs are significantly less than aggregated costs, cities may see some advantages to municipalizing, although they would also incur certain costs for doing so.

SVP and others were concerned that LSEs that do not have a large, dispersed customer base could be at a competitive disadvantage because they could not spread higher costs over a large, geographically disperse customer group and favor aggregation at a larger level.

> ISO Response: This is a valid concern. The transition from aggregated to localized pricing will need to take place over a reasonable time and account for factors such as transmission adequacy and the competitiveness of available supply.

CDWR suggested that it may be necessary to schedule and settle by node to remove the need for RMR contracts, solve the current RMR cost allocation problems and send price signals to drive construction of new generation and transmission in locally constrained areas.

> ISO Response: The ISO fully intends to schedule and settle generation and participating loads at the nodal level to ensure feasible forward schedules and correct pricing and allocation of the grid. For RMR and local reliability considerations, however, pricing at the LRA level may be adequate. At the same time, FERC has recognized and the ISO agrees that locational price signals are not sufficient to drive transmission and generation investment in constrained areas, and that an effective grid planning and upgrade process is required.

Migration from Larger to Smaller Load Aggregations. SCE recommended that demand scheduling and settlement continue to be on a utility service area basis as it is done today rather than by smaller load areas. CCSF requested the data supporting the underlying price differential information used by the ISO in designing its load aggregation scheme to understand the cost and cost shifting impacts of the ISO proposal including the impact on loads of the "migration to smaller local aggregations" and how such migrations will occur.

> ISO Response: The ISO has met with some stakeholders to discuss data supporting various load aggregations and plans to continue such discussions as we transition to more localized aggregations. Unfortunately the data on price differentials is imprecise at this time, since the ISO has not been running a nodal market and must rely on simulations to produce local price estimates. It is important to remember in this regard that locational pricing for loads will not begin until the ISO implements the full network model (FNM) in fall of 2003. The ISO intends to have the FNM running in test mode and to publish nodal prices for several months in advance of implementation in the market, to provide a substantial period of data on which to develop realistic patterns of locational prices and assess their impacts. In addition, a complete picture of cost impacts only emerges from considering the combined effects of locational ACAP obligations, RMR contracts, and FTR allocation, in addition to LMP.

Stakeholders disagreed on whether such migrations should be voluntary (CCSF) or whether voluntary aggregation would create different prices for the same product, thus creating opportunities for non-beneficial strategic behavior.

ISO Response: The ISO believes that the incentive for loads in low-price areas to opt for nodal prices is a desirable effect of the LMP model. The potential for strategic behavior or gaming is readily eliminated by limiting the ability to switch between nodal and aggregated prices; e.g., a given consumer might have to remain with one pricing mode for a minimum of 6 months or so

CCSF recommended that workably competitive pricing of supply be a prerequisite before such migrations occur.

ISO Response: The ISO agrees that this should be one of the considerations, although other factors such as technical feasibility and transmission adequacy should be considered, as well. Bid mitigation for locational needs is an effective way to address this issue. Indeed, all ISOs that use LMP must have provisions to address local market power under the LMP scheme

CCSF also believes that it is appropriate to aggregate load for settlement and scheduling when imposing an LMP regime, as is done in PJM, but it is not clear that FTR allocation and reliability service procurement should take place using different aggregations.

ISO Response: FTR allocations will be designed to give LSEs appropriate tools to hedge their risks associated with congestion costs while reliability services will be procured to meet local needs at whatever level is appropriate at each location.

Demand Responsiveness. The ISO should carefully consider how to facilitate demand responsive bidding to the extent it can be realistically anticipated to occur under the new market design (CCSF) and whether it is being valued more highly than generation.

ISO Response: The ISO's current design would price demand response at the same level as generation at the node at which it is scheduled or bid.

Demand should be treated as similarly to generation as possible for price responsive instructed dispatch. It is not necessary for all load to be exposed to an hourly varying locational price signal to gain the benefits of demand response. (Palo Alto).

ISO Response: The ISO agrees with these positions. A difference between price-responsive bids for load and generation is that start-up and minimum-load components of load bids may be market-based instead of being subject to cost justification.

Non-Standard Load Aggregations. CDWR suggested that the ISO include "non-standard load aggregations" to accommodate the operating requirements of loads that are physically linked and need to be dispatched consistently, despite being in separate zones (or nodes) (CDWR).

ISO Response: The ISO will consider these as we move forward with the MD02 design.

8 Damage Control Bid Cap (DCBC)

Need for a DCBC. Some stakeholders (Calpine, IEP) commented that it is not necessary to have both an AMP mechanism and a damage control bid cap in place while others (CCSF) stated that continuing a DCBC is crucial during the transition period. CMUA reserved judgment until it better understands how energy limited thermal units would be affected by the DCBC and whether they could be subject to under-collection of costs. Other respondents disagreed on the need for a DCBC with some stating that the DCBC proposal is a mechanism to artificially reduce wholesale prices rather than to mitigate market power while others asserted that DCBC should not only be for "damage control" but should also be an integral part of the market power mitigation rules.

ISO Response: Without the price mitigation provided by the FERC market mitigation orders, the spot markets will be vulnerable to extreme peak prices. All other ISOs have some level of damage control bid cap (DCBC) to limit the adverse cost impacts of an unusually severe price spikes. The ISO believes that the DCBC and AMP are complementary tools for mitigating market power. The DCBC is applied to the entire market and limits the magnitude of price spikes whereas AMP limits the frequency of price spikes by limiting supplier's ability to abruptly change their bids to take unjust advantage of unique circumstances. The ISO's intent is to set the DCBC at a level that will ensure that suppliers can recover their costs and that adequate supply will be made available to the ISO's market during high demand periods. An effective market power mitigation approach must strike a balance between providing adequate safeguards for mitigating market power and ensuring adequate incentives exist for correcting structural deficiencies.

Magnitude of DCBC. Stakeholders were divided on the desired level of the DCBC. Mirant stated that any cap should be set high enough so that marginal units (CTs/peakers) have an opportunity to recover their fixed and operating costs and IEP believes that the DCBC should provide price signals that encourage demand-response and infrastructure improvements. Others commented that the proposed DCBC may be too high and may subject consumers to unnecessary price spikes without leading to long-term investment.

ISO Response: The ISO believes the level proposed is consistent with the following fundamental design principle that the ISO provided in its earlier draft document on market power mitigation:

> *If we adopt market power mitigation measures in the wholesale markets that ultimately slow progress toward correcting the fundamental structural deficiencies that enable suppliers to exercise market power, these measures may, in the long run, actually harm the consumers they were intended to protect. An effective market power mitigation approach must strike a balance between providing adequate safeguards for mitigating market power and ensuring adequate incentives exist for correcting structural deficiencies.*

Specific suggestions included setting the DCBC:

No higher than that proposed by the CPUC President, i.e., to initially set the cap at the current level of west-wide mitigation, or about $100/MWh - especially given the drop in gas prices since June 19, 2001 (***CCSF***);

At the higher of $100/MWh or $(20 *(Daily Gas Index) + 6)/MWh, as long as units that could exercise locational market power must bid at their variable cost. (***Palo Alto***); or

Based on a daily, rather than a monthly gas price (***Mirant***).

At the level prescribed in the current west-wide mitigation regime (including indexing to gas prices). (***SCE***)

Based on the highest reported peak spot prices at the major market hubs in the western interconnection. (***Sempra***)

At approximately $150/MWh because the average cost of production is substantially lower than $150. (***SMUD***)

ISO Response: All other ISOs have some level of damage control bid cap (DCBC) to limit the adverse cost impacts of an unusually severe price spike. Based on further discussions, the ISO is proposing a DCBC based on the current west-wide mitigation regime; i.e., to be set at an initial level of $108 per MWh with the ability to be increased as needed in conjunction with gas price increases. Although the eastern ISOs have a DCBC of $1000 per MWh, the ISO does not believe this is an appropriate level for the California market due to the fact that the structural elements necessary to ensure a workably competitive market are not in place, and as a result a DCBC will likely be hit more frequently than in the eastern ISO markets. The ISO believes that over time, if market conditions improve, the DCBC could eventually be raised to a level commensurate with the eastern ISOs.

Other Stakeholders suggested that:

Once the full market design is implemented, the DCBC should be raised to a level that does not suppress competitively determined market clearing prices or block entry of new supply (***Sempra***);

ISO Response: The ISO agrees and plans to do so in the long term, as competitive conditions in the California markets improve adequately.

A DCBC in California should not be lower than in other jurisdictions. The latest proposal would not unduly impair ability to manage risks, but it should be indexed to daily rather than monthly gas prices. (***Mirant***)

ISO Response: The level of the Damage Control Bid Cap must strike a balance between ensuring sufficient supply is made available to the ISO's real-time market and providing incentives for correcting the structural deficiencies that enable the exercise of market power and ensuring that proper safeguards are in place to mitigate against excessive market power abuse. In developing its recommendation, the CAISO strongly considered stakeholder comments.

Incentives for New Generation. CCSF believes that incentives for demand response and new generation development are irrelevant to the design of a DCBC and price spikes in spot markets do not provide incentives for long-term generation development. Palo Alto believes that there is a role for bid cap with potential for price spikes to create incentives for demand response, but that generation, demand relief and transmission projects that address local/regional reliability are more appropriately funded through long-term contracts with the energy price based on dispatch costs.

ISO Response: The ISO believes that the potential for spot market volatility (e.g. upward and downward price spikes) provides market participants with the proper incentive for forward contracting, generation development, and demand response. However, the ISO believes that until the structural deficiencies in the California market are sufficiently corrected, including the establishment of credit worthy utilities empowered with the ability to procure and manage a diverse forward energy portfolio, that a relatively moderate DCBC is necessary.

Applicability of DCBC. Some stakeholders (CCSF) recommended that DCBC should apply to all markets, i.e., ancillary services, adjustment bids and energy markets. Others were concerned that a low DCBC continuing "until market conditions are competitive enough to support a higher" cap is vague and the ISO should provide a more precise and transparent standard (IEP).

ISO Response: Since the Available Capacity (ACAP) Obligation will be phased in over time, and remedying other market deficiencies (e.g. utility credit worthiness, demand response, supply adequacy etc) will take time, to protect against market power in the transitional period, the ISO believes it is prudent to start with a relatively low bid cap and gradually raise it as capacity conditions improve. The bid cap would apply to all resources submitting bids in the ISO markets (including imports) and the same bid cap would apply to both energy and ancillary service capacity. A 12-month competitive market index is being proposed as a prospective standard to measure market competitiveness.

9 Bid Screens and Mitigation

Special Purpose Resources. CDWR commented that, the ISO's draft Automated Mitigation Procedure (AMP) may be inappropriate for CDWR's system whose primary obligation is water delivery and management because its application would limit market participants' abilities to "bid high" to indicate their desire not to be dispatched readily, leaving only the option of staying out of the market altogether. CDWR recommends that the ISO designate bids of such resources as "last resort" bids that would not be dispatched until after all other merchant generators and loads and pay such resources for energy at MCP or as-bid, effectively removing the need for AMP for these resources.

ISO Response: Since AMP Reference Levels are proposed to be bid based, there is nothing precluding resources from bidding high to reflect their energy limitations. To the extent such bids are dispatched over a ninety day period, they will establish the bid Reference Level for the resource. As long as such bids are within a reasonable range of the resource's bid Reference Level, they will not be subject to mitigation. However, the ISO DMA will be monitoring the bidding patterns of resources and resources owners may be asked to justify their bidding patterns and resources that have bid patterns that appear to be based on a persistent pattern of uncompetitive bidding will be reported to FERC.

Application of AMP to Loads. CDWR commented that the ISO's proposal does not explain how AMP would apply to loads.

ISO Response: The ISO at this time has not developed a proposal to apply AMP to participating loads.12-Month Market Competitiveness Index

General Comments. Stakeholders were divided on whether the proposed 12-Month Market Competitiveness Index would be a valuable market power mitigation tool. SCE supports this proposal as one possible metric (although it does not cover all situations) while Sempra believes that this should not be a part of our permanent market design. Instead they argue that this should be a temporary measure and only applied to generation that has locational market power.

ISO Response: This tool is one of several mitigation measures that has been proposed in the MD02 plan. The 12-month market competitiveness index provides a higher level of protection against sustained market power than other mitigation procedures and will be a permanent feature of MD02 until market conditions change.

Application of the MCI. CMUA and Mirant opposed the MCI, believing FERC to be the sole authority to determine just and reasonable rates and/or market competitiveness. CCSF requested additional information about how bid screens worked in New York, questioned how that situation applies to the California market and questioned whether using historical bids in similar hours would work in California's "dysfunctional market." SMUD raised the concern that once the threshold is exceeded there is no defined exit strategy to return the market to a non-mitigated position and that the ISO has too much discretion without sufficient checks and balances.

ISO Response: The ISO agrees that FERC is the final authority in this matter and in submitting our plan to them for approval, the ISO is deferring to their discretion.

Definitions. Some Stakeholders requested further clarification on various terms including:

What constitutes "material impact" on market clearing prices (***CCSF***)?

The definition of "competitive markets" is based on the ISO's "litigation posture in the refund proceeding and therefore not independently robust" (***IEP***).

"Marginal costs" are also replacement costs, not historic cash expenditures (***Mirant***). Bids and MCI Level: ***Mirant*** commented that the MCI may be ineffective because bidders without market power would bid based on their estimates of the risk-adjusted marginal costs of their next closest competitors rather than their own risk-adjusted marginal costs. ***EBMUD*** recommended that the reference level for energy limited resources be set at the same level as gas fired resources and compensated at MCP.

Impacts on Hydro Resources. BPA expressed concerns about the variability of hydro generation from year to year because a dry year followed by a wet year the rolling 12-month average could be skewed.

ISO Response: This could occur, but bidders will always be able to receive at least their marginal cost.

10 Application of MD02 to Governmental Entities

Support for MSS. CDWR and SVP supported properly designed MSS as offering advantages to both the ISO (such as reduced ancillary serviced procurement requirements) and Government Entities while PG&E questioned the basis for allowing Government Entities to qualify for MSS status while eliminating IOUs from eligibility and was concerned that the proposed eligibility requirements for MSS could be considered unduly discriminatory by implying that IOUs do not or will not have the obligation to serve consumers.

ISO Response: The ISO has developed its proposed criteria for applying MD02 to Governmental Entities (GE) in view of the State and federal law applicable to those entities. Because of limitations on GEs' abilities to make resources funded by public funds available in the market, the ISO believes it is appropriate to offer special considerations that would be applicable to entities that met ISO Tariff criteria for Metered Subsystems.

CDWR further stated that ISO must provide some flexibility in the definition of an MSS, suggested that the ISO may need to offer physical firm transmission rights to prevent transmission interruptions to dispersed loads and enhance opportunities for self-supply and bilateral transactions and recommended that all transmission service to loads be available on a long-term firm basis.

ISO Response: The ISO is attempting to address the desires expressed by CDWR and others for longer-term transmission rights by offering longer-term FTRs as part of the MD02 design.

Outstanding Questions. PG&E questioned which ISO charges MSSs would be not be subject to (this issue will be resolved subject to the results of negotiations currently underway), how the ISO would distinguish between ordinary emergencies and those due to identifiable resource deficiencies and whether limits on the ISO's ability to dispatch MSS units would compromise reliability.

ISO Response: Emergencies due to resource deficiencies would be identifiable by the ISO in the DA Market while ordinary emergencies occur in Real Time. The ISO will not have limits on dispatching MSS units under system emergencies, thus does not believe this proposal would compromise reliability.

11 Compliance Monitoring Requirements

General Support. Reasonable compliance monitoring, such as requiring accurate scheduling, and appropriate penalties for lack of compliance are a necessary ISO function if they are approved by FERC and applied in a nondiscriminatory manner (PG&E, SVP). Compliance should be accomplished cost-effectively (SVP)

ISO Response: The ISO appreciates this support for reasonable compliance monitoring and penalties and agrees that it should be accomplished cost effectively.

12 Financial Settlements

Cost Causation. All costs incurred by the ISO should be recovered on the basis of "cost causation" or, to the extent that it is not possible or not practical to allocate or directly assign costs, a "second best" approach should be developed based on appropriate analysis (SVP).

ISO Response: The ISO agrees that cost causation should direct cost allocation and is working to apply this principle to MD02 design elements whenever possible.