CALIFORNIA ISO

California Independent
System Operator

February 19, 2003

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

Re: Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Docket No. RM01-12-000

Dear Secretary Salas:

Enclosed for electronic filing please find the Initial Comments of the California Independent System Operator Corporation regarding the Standard Market Design Notice of Proposed Rulemaking.

Thank you for your assistance in this matter.

Respectfully submitted,

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

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Remedying Undue Discrimination	)	
Through Open Access Transmission	)	Docket No. RM01-12-000
Service and Standard Electricity	)	
Market Design	)	

INITIAL COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION REGARDING THE STANDARD MARKET DESIGN NOTICE OF PROPOSED RULEMAKING

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February 19, 2003

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design	))))	**Docket No. RM01-12-000**

Initial Comments of the California Independent System Operator Corporation Regarding The Standardized Market Design Notice Of Proposed Rulemaking

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Pursuant to the "Notice of Comments and Revisions to Public Comment Schedule" issued by the Federal Energy Regulatory Commission ("Commission") on October 2, 2002 and the "Notice on Requests for Additional Time" issued by the Commission on December 20, 2002, the California Independent System Operator Corporation ("ISO") hereby submits its comments regarding "Notice Of Proposed Rulemaking" ("NOPR") in the captioned proceeding [1] The ISO also was a co-sponsor of the *Joint Comments of RTO/ISO Group* that were filed on November 12, 2002. The ISO generally supports the Commission's objective of developing consistent wholesale market designs across regions. The ISO notes that most of the elements of the proposed standard market design ("SMD") are consistent with the ISO's Comprehensive Market Redesign Proposal ("MD02") in Docket No ER02-1656-000 However, the ISO submits that numerous aspects of the Commission's proposed standard market design require clarification and/or modification. Further, a standard market design must, out of necessity, address and resolve rate and transition issues associated with implementation of any standardized transmission service. In addition, the standard market design should accommodate regional

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1 *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design, FERC Stats & Regs* [Proposed Regulations], ¶ 32,539 (2002) Given the extreme press of other regulatory matters, the ISO was unable to file its initial comments on the NOPR by January 10, 2002. In accordance with the Commission's December 20, 2002 "Notice of Requests for Additional Time", the ISO requests that the Commission accept these late-filed comments.

flexibility and recognize that market conditions vary from region to region In particular, the Commission must take regional market conditions into account in determining the appropriate market power mitigation measures to be in place in a given region.

I. Introduction

The ISO applauds and supports the Commission's overarching goal to develop consistent rules, standards and practices across regions. The Commission's efforts are appropriately focused on aligning market rules to support reliable and efficient use of the system and to establish market signals that create incentives for investment in electric infrastructure. To that end, the ISO believes that the Commission's objectives and goals are aligned to support the core functions of an Independent Transmission Provider ("ITP"), *i.e.*, that of providing open, non-discriminatory, and reliable transmission service.

A. A Framework For Investment

In order to achieve the aforementioned objectives and obtain the benefits of efficient and competitive markets, federal, state and local policymakers need to create the institutional and regulatory framework necessary to support infrastructure investment. Federal, state and local agencies must establish clear rules that facilitate and attract the investment that is necessary to support reliable grid operations and efficient markets.

These rules come in many forms. In particular, the need for clear rules regarding forward contracting is self-evident Forward contracting is the vehicle through which investment will occur. Forward contracting provides the revenue stream necessary for investors to back new infrastructure - be it generation, transmission or demand-based resources. In addition, regulators must provide *certainty* with regard to timely rate recovery for load-serving entities ("LSEs") that enter into such forward contracts. Absent clear, specific rules regarding procurement and cost recovery, market participants will be unwilling to contract with load-serving entities and financiers will be unwilling to invest in critical infrastructure. The end result is obvious – higher prices and load curtailment. There is perhaps no more urgent need than to restore confidence in regulatory institutions and the markets they support.

Furthermore, to support necessary investment and forward contracting, policymakers need to establish clear roles and responsibilities within the framework that furthers resource adequacy. LSEs need to have the clear responsibility (and authority) to procure adequate capacity resources in the forward market; capacity resources sufficient to satisfy their load plus reserves In addition, suppliers need to have clearly established requirements regarding their obligation to be available to serve load (and at what price) and need to understand clearly the consequences of their supplies not being available. The roles and responsibilities of ITPs also need to be clearly defined. For example, is the ITP the procurer of last resort? Can the ITP curtail the load of LSEs that have failed to procure adequate resources to serve their load? The roles and responsibilities of all of these entities need to be precisely defined and understood. Once understood, the roles and functions can be seamlessly integrated to create a framework that supports reliable and efficient market outcomes from the long-forward market – prior to the day-ahead - through the spot markets and into real-time operations.

B. Making Markets Work

The short-term markets necessary to allocate access to the transmission system efficiently and support reliable operations must be built on an institutional and regulatory foundation that encourages infrastructure investment, but they must also be built from a consistent, robust, and safe market design The ISO supports the Commission's goal to align, to the extent practical, the market structures and designs across regions. Compatible market rules support inter-regional trading and promote the further development of established markets While many regions of the country have benefited from active and liquid markets, further aligning the market rules across regions should facilitate more efficient market outcomes and permit all consumers to capture the benefit of lower costs.

The ISO believes there are several critical requirements for creating robust, competitive electricity markets, which the NOPR addresses, including: (1) transparent spot markets tied directly to real-time physical delivery, which can serve as the reference for forward trading and contracting; (2) non-discriminatory access to transmission service; (3) clear definition of the reliability role of the ITP, which must have adequate authority and tools to ensure reliable operation within the market framework; (4) resolution of inter-control area or "seams" issues to facilitate trading across control area boundaries, and (5) new institutional arrangements to enable regional collaboration on issues that have broad geographic impact (such as transmission planning), and to facilitate effective coordination between the various state and local regulatory authorities and the Commission where jurisdictional boundaries intersect. The ISO believes that the NOPR offers constructive proposals in all these areas.

The ISO is concerned, however, that the target date of September 30, 2004 for implementation of the SMD *in all jurisdictional transmission systems* will be extremely difficult to achieve The ISO believes that it will be necessary and appropriate for the Commission to account for regional variation in the timetable Flexibility in timing is paramount if the Commission is to ease certain of the tensions associated with transitioning from one paradigm to another. Some of the main ingredients of this paradigm shift are

- Clearly delineating financial versus physical transactions, substituting financial certainty for physical certainty in the market process, and then adapting to the new landscape of risks and uncertainties (for example, tradable Congestion Revenue Rights instead of bilateral long-term transmission contracts), while still providing physical certainty in real-time;
- Scheduling transmission service on a point-to-point basis rather than on a contract path;
- Obtaining services such as operating reserves (if not self-provided) and balancing energy from a central pool operated by an independent transmission system operator, and turning the required operational control of facilities over to that operator (i e , the

difference between a decentralized, bilateral market predicated on self-scheduling and control versus a central market where the operator optimizes among and between all resources made available);

- Creating a centralized settlement system for spot market transactions;
- Enhancing demand response's role in moderating spot market price volatility, and improving infrastructure to enable the timely flow of price information to that demand;
- Revising state and local energy policies to ensure supply adequacy in a world where supply capacity is transacted in markets.

Moreover, different regions of the country presently are at very different points in these cultural and paradigm shifts. Some regions, such as New England, New York and the states in which PJM operates, are well accustomed to participating in a common pool operated by a central system operator. Other regions are still perfectly satisfied with the integrated monopoly utility industry model and have yet to be convinced of the benefits of adopting the new competitive market model. In particular, the Commission must recognize that the West has no history of region-wide tight or central regional power pools (although it does have a strong history of coordination) and is just now emerging from the 2000-2001 energy crisis. As a result, the Commission must permit the West – but particularly California - to reestablish the balance between long-term forward contracts and spot market purchases In addition, this history has created the potential for smaller (rather than larger) power pools These issues will make it difficult, if not impossible, to achieve the target date.

Finally, regardless of the details of any standard market design ultimately adopted by the Commission or developed by each region, the ISO believes that adequate market monitoring and market power mitigation measures must be in place to prevent another catastrophic market collapse. While the ISO believes that the Commission has correctly identified the necessary structure and components of such a monitoring and mitigation framework, the ISO recommends that the Commission allow for regional flexibility with respect to proposing regional price caps and mitigation thresholds. Such metrics cannot and should not be standardized but should be established based on an assessment of the exigent market conditions that exist in each region.

C. Process Going Forward

Subsequent to the issuance of the NOPR, the Commission was presented with a growing consensus in many parts of the country that the Commission should defer to local/regional entities to develop a market design and structure that works best for their region. There is a broad and strong consensus on this issue in the West. As a result, over the past several months the Commission has engaged in renewed efforts to build consensus. More recently, the Commission's stated objective has evolved from requiring a "standard" market design across the nation to facilitating "consistent" market designs across "regions." The ISO supports such an objective and is attempting to promote such an outcome by actively participating in the ongoing Seams Steering Group – Western Interconnection ("SSG-WI"), Western Electricity Coordinating Council ("WECC"), Committee of Regional Electric Power Coordination ("CREPC") processes, as well as other forums.

The ISO notes that in a press release issued January 12, 2003, Chairman Wood stated that the Commission has "embraced the flexibility needed to accommodate regional concerns," and that "[w]e will continue to do so in implementation as well." Chairman Wood also stated that, "[t]he Commission engaged in an extensive public outreach in developing the SMD proposal and will continue to listen to all constituencies in developing its final rule," emphasizing that "[w]e have listened to customers, the Congress, state regulators, the industry, and academics." In conclusion, Chairman Wood indicated that the Commission would issue a "White Paper" regarding the SMD process sometime in April and the press release stated that it is more important to do it right than to do it quickly, and customers deserve no less. The ISO agrees with these statements and supports the Commission's efforts to accommodate regional variation. Moreover, the ISO concurs with the Commission's desire to develop the "right" market design for each region rather than having all regions meet an aggressive pre-determined timeframe.

II. Executive Summary

In this section the ISO summarizes its recommendations regarding the various issues raised in the NOPR. The ISO addresses each design feature/issue starting with those issues applicable to the long-forward market (*i.e.*, well before the day-ahead market), then those issues involving the forward markets (day-ahead and hour-ahead), and, finally, the real-time market. The ISO also offers comments on the other related functions and services outlined in the NOPR.

For purposes of these comments, the ISO uses the term "ITP-region" and "region" synonymously Thus, with respect to the ISO, region means California and "inter-regional" or "supra-regional" means the Western interconnect or the entire Western market.

A. The Long-Forward Market

1. Resource Adequacy

The NOPR proposes to establish a resource adequacy requirement under an ITP's tariff that would require all LSEs to procure sufficient resources to satisfy their peak load plus reserves equal to 10-12 percent. If such LSEs fail to procure sufficient resources, the NOPR proposes that they be subject to priority curtailment and pay a surcharge for energy purchased through the ITP's real-time market. This proposal is similar to the available capacity ("ACAP") obligation filed by the ISO as part of its MD02 proposal in Docket Nos. ER02-1656, *et al*

Consistent with the ISO's recent filings and desire to support California's efforts to create a resource adequacy framework, the Commission should defer to the State's efforts and not prescribe a generic resource adequacy mechanism. The ISO is concerned that potentially conflicting federal and state resource adequacy requirements could do more harm than good and may, as a result of such conflicting standards, further the flight of capital from the California electricity market. At a minimum, the ISO recommends that the Commission defer to State and regional efforts before establishing any minimum requirement for users of the ISO Controlled Grid.

2. Regional Transmission Planning

The Commission proposes that a regional transmission planning process be instituted within six months of the effective date of the final rule in this proceeding (and the first regional transmission plan completed within twelve months). The NOPR states that the regional planning process should be designed to identify beneficial transmission needed for both reliability and economic reasons to support regional markets and reduce the effects of generation concentration The NOPR provides that the regional planning process should allow the market to respond to those identified needs.[2] The Commission states that, as recommended by the National Governors Association, Multi-State Entities could be an important component of the regional planning process. With respect to the West, the Commission states that planning should be done on a Western Electricity Coordinating Council ("WECC") area basis.

The ISO supports creation of a regional planning process that furthers the economic expansion of the transmission system In particular, the ISO supports the ongoing SSG-WI planning work group efforts to create a regional planning process that will promote the development of economic transmission projects across the West.[3] Moreover, the ISO supports other regional entities' efforts, such as those of the Western Governors' Association and the Committee on Regional Electric Power Cooperation ("CREPC").

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2 Specifically, the NOPR provides that ITPs should issue requests for proposals when the process determines additional resources are needed. The ISO notes that in a press release issued January 13, 2003, the Chairman Wood indicated that this competitive procurement process could slow down needed transmission investment in the near term, and therefore should not be included in the Commission's final rule The ISO shares the Chairman's concern.

3 Under the draft SSG-WI regional planning construct, reliability-driven transmission expansions would continue to be evaluated at the RTO level

The ISO's existing coordinated grid planning process has been very successful, resulting in around $1.5 billion in transmission investment being approved to date Any regional planning process should build off of successful programs such as the ISO's. In addition, the ISO is committed to working with State agencies to further streamline the transmission planning and siting process. As part of that effort, as well as the larger effort to create a regional planning process, the ISO requests that the Commission support efforts to develop the criteria necessary to demonstrate the "need" for "economic" transmission projects that support interregional transactions.

Finally, the ISO is concerned that many issues and details regarding the Commission's proposed competitive solicitation process – the process to decide among transmission, generation and demand-based alternatives to satisfy identified system needs - require further consideration and development. While the ISO recognizes the benefit of integrated planning and supports the concept of a competitive solicitation process, the ISO cautions the Commission that it must resolve a number of difficult policy issues before requiring ITPs to conduct competitive solicitations Based on the ISO's experience with these matters, the ISO recommends that the Commission offer guidance on the criteria to be used to evaluate transmission, generation and demand-based alternatives. Moreover, at a minimum such examinations should be coordinated with (if not deferred to) state efforts regarding resource procurement and integrated planning.

3. Demand Response

The NOPR states that the participation of demand in the market is critical for an effective wholesale market and advocates permitting demand to bid directly in the market with load bids. However, the Commission does not support costly measures such as those where an ITP pays load more than the market clearing price to reduce demand.

The ISO believes that the primary vehicle for facilitating the development of price-responsive demand programs should be the resource adequacy mechanisms ultimately adopted by each region. The ISO agrees with the Commission that it often has been necessary to pay load above-market prices in order to attract participation in demand response programs The ISO believes that resource adequacy-related mechanisms offer a means to provide load that participates in such programs with adequate compensation Similar to new generation, load-based resources often have start-up capital expenditures for which they need complete and timely cost recovery. Long-term forward contracts (*i.e.*, bilateral contracts) negotiated in the context of satisfying a resource adequacy requirement offer such a cost-recovery vehicle. Because facilitation of demand response goes hand-in-hand with developing and implementing a framework for resource-adequacy in each region, the ISO recommends that the Commission defer to state and regional processes and authorities to develop such programs

Finally, while the ISO does not believe that an ITP necessarily must *develop* demand response programs, the ITP must at least *facilitate* demand participation in its markets. Thus, the final rule must ensure that whatever standard wholesale market design is ultimately adopted, the design must include the "functionality" necessary to facilitate load participation. For example, if the Commission standardizes the three-part bid structure inherent in the existing Eastern independent system operators (and proposed by the ISO in its MD02 proposal), the Commission must ensure that such cost/bid-based structure permits demand to bid in manner to recover verifiable costs incurred as a consequence of participating in a ITP's markets.

4. Congestion Revenue Rights

The NOPR acknowledges that Congestion Revenue Rights ("CRRs") can be either allocated or auctioned to market participants. While expressing a preference for auctioning these rights, the Commission states that it may be appropriate to allocate CRRs to those entities that have historically paid the embedded cost of the transmission system (*i.e.*, load). In addition, the Commission advocates the CRRs be allocated or given to those entities that fund expansion of the transmission system (and which do not seek to recover the embedded costs of such expansion from users) Finally, the Commission states that ITP's are required to offer obligation-type CRRs initially and should provide option-type CRRs when technically feasible.

The ISO generally supports the Commission's proposal for issuing CRRs. The Commission's proposal regarding CRRs is generally consistent with the ISO's MD02 proposal. Specifically, the ISO's MD02 proposal provides that the ISO would initially provide *obligation*-type CRRs, but later would provide *options* when they become available.[4] The ISO also proposed to allocate CRRs to LSEs in order to reduce certain concerns about the transition to LMP pricing[5] Moreover, the ISO proposed to allocate CRRs to those entities that expand transmission capacity (but do not seek capital cost recovery from the ISO).

5. Transmission Pricing

The NOPR contemplates that ITP's will recover the embedded costs of the transmission owners that have turned operational control of their facilities over to the ITP through load-based access charges. The NOPR also states that the Commission will permit the use of license plate rates (*i.e* , load only pays the embedded costs of the transmission owners in whose area it is located) but inquires whether it should retain license plate rates only for a transition period.

The Commission should allow the ITP, transmission owners, and market participants in each region to develop an access charge structure that works best for them. The ISO's current voltage level-delineated, transmission access charge "area" structure, that provides for a ten-year transition to a rolled-in rate for high-voltage facilities, resulted from long negotiations

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[4] The ISO would offer CRR Options to holders of existing transmission contractual rights that are willing to convert their existing rights to CRRs

[5] The ISO proposed to allocate CRRs to load in part to recognize load's historical contributions to the embedded cost of the transmission system, but also to alleviate concerns arising from the transition to LMP A number of parties raised concerns that LMP will expose them to higher prices and that such an outcome is unfair since all along they have been paying for the embedded cost of the entire transmission system In recognition of this legitimate equity issue, the ISO proposed to allocate CRRs directly to load in order to allow such load to hedge directly the cost of congestion and hence the higher prices that may result from LMP

between the parties. The ISO recommends that the Commission defer to such regional processes to develop pricing proposals that will represent a unique balancing of benefits and burdens for each party and region Of course, the Commission ultimately may be required to provide specific guidance/directives to parties to resolve contentious cost-shifting issues.

As a general matter, the ISO is concerned that the NOPR does not adequately integrate transmission pricing and generator interconnection policies. In particular, the ISO is concerned that while, on the one hand, the Commission is proposing transmission pricing policies designed to promote efficient allocation and expansion of the transmission system and to send accurate locational price signals for new resources, the Commission also proposes, in its Notice of Proposed Rulemaking in Docket No. RM02-1-000, *i.e.*, the so-called Generator Interconnection NOPR, to adopt generator interconnection policies that may lead to inefficient and inappropriate expansion of the transmission system. Specifically, in the Generation Interconnection NOPR, the Commission proposes that generators receive transmission credits equal to the amount paid to the transmission provider for network upgrades.[6] Further, in several cases, the Commission has directed transmission owners to develop a crediting mechanism whereby new generators receive a credit for all new transmission necessary for the generator to interconnect to the system.[7] The ISO understands and supports the Commission's objective of facilitating the entry of new supplies into the market by reducing barriers to entry such as interconnection costs. However, the ISO submits that any such policy must be balanced against the need to send accurate and appropriate locational price signals for the location of new resources. The

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6 *Standardization of Generator Interconnection Agreements and Procedures*, FERC Stats & Regs [Proposed Regulations], ¶ 32,560 at 34,219 (2002).

7 Under the Commission's directives, a generator can demand that an ITP expand its transmission system with initial funding by the generator, but then the generator can receive a full credit for the cost of those facilities over, for example, a mere five years *See, e.g., Southern California Edison Company, Agreement For Filing,* 97 FERC ¶ 61,148 at pp 12-13 (2001); *see also, Consumers Energy Co* , 95 FERC ¶ 61,233 (2001), *order on reh'g* , 96 FERC ¶ 61,132 (2001).

Commission's proposed interconnection policies would not do so and, in fact, may undermine the very policies it seeks to promote with respect to transmission pricing.

6. Existing Transmission Contracts

The NOPR recognizes that in order to ensure consistent market rules and equal access to all customers, previously existing transmission service contracts need to be conformed to the rules outlined in the NOPR. However, the NOPR does not contemplate the abrogation of these existing contracts (although the Commission did just that when it restructured the natural gas industry). Instead, the NOPR proposes that the previous transmission providers under those contracts be required to take service under the ITP's tariff to satisfy their obligations under the existing contracts. In other words, the existing contract rights holders would still be entitled to transmission service under the same terms and conditions that existed under their existing contracts. However, the previous transmission provider would have to schedule that service under the ITP's tariff and, to the extent any cost differences result (*i.e* , differences from what they are paid under the existing contract and what they pay under the ITP's tariff), the previous transmission provider would have to pay the difference The Commission also proposes that such previous transmission providers be entitled to recover these costs under their established transmission revenue requirements.

The ISO does not oppose the Commission's proposal. The ISO has long recognized that providing transmission service to existing contract holders under a different set of market rules than apply to other customers invariably leads to inefficient market outcomes. "Phantom" or paper congestion exists in California because the ISO is required, in the day-ahead scheduling process, to set aside transmission capacity for potential use by existing transmission contract customers. Frequently, this capacity goes unused. However, as a consequence of "setting it aside," other users of the system are charged for congestion that does not really exist. Therefore, the ISO does not oppose the SMD proposal regarding the treatment of existing transmission contracts, including the ability of the previous providers to recover any costs incurred as a result of having to take service under the ITP's tariff. The ISO notes that, under SMD, existing transmission contracts (as covered by transmission owners) would follow the same scheduling timeline as the rest of the market, thereby reducing the day-ahead phantom congestion problem. However, before prescribing a standard approach for addressing this issue, the ISO believes that further examination of this issue is warranted. The ISO requests that the Commission defer to the ongoing MD02 process to fashion a solution that works best for California.

B. The Forward Market

1. New Network Transmission Service

The NOPR proposes to require that all ITPs offer only one service – Network Access Service – which is a new form of network transmission service Previously, under the Open Access Transmission Tariff (OATT) required under FERC's Order Nos. 888 and 889, transmission providers were required to offer both network transmission service and point-to-point transmission service. The ISO supports the Commission's proposal. In fact, the ISO offers today the virtually the same network service described by the Commission in the NOPR.

2. Integrated LMP-based Forward Market

The NOPR proposes that each ITP facilitate an integrated forward market that simultaneously optimizes energy, ancillary services, and transmission congestion. Thus, instead of conducting separate and discrete markets for energy, ancillary services and transmission (as the ISO does today for transmission and ancillary services), ITPs would facilitate an integrated market. The Commission also proposes that the integrated market be based on the Locational Marginal Pricing ("LMP") regime that also serves as the basis of economic dispatch in the real-time market. The ISO supports the Commission's proposal to establish an LMP-based integrated forward market. Indeed, the ISO's MD02 proposal includes an integrated forward market based on LMP that is consistent with the Commission's SMD proposal[8] Such a market is more efficient than a sequential market. Pricing both the real-time and the forward market on a LMP basis will ensure "consistency" between the forward and real-time markets. Such consistency supports reliable real-time operations by establishing forward-market price signals that are consistent with real-time prices and operations, thereby reducing the need for operators to employ non-transparent actions in real time.

The Commission also proposes to require ITPs to permit buyers and sellers to submit purely financial bids This is typically characterized as "virtual bidding." Importantly, the Commission states that such bids must be clearly identified or "flagged" so that the ITP can easily distinguish between the purely financial bids (and thus not backed by a physical resource) and physical bids (bids backed by the physical resource). This is typically referred to as "explicit virtual bidding." In contrast, "implicit virtual bidding" is the submission of purely financial bids where there is no physical resource behind the bid (and such fact is not indicated to the ITP)

The ISO believes that "implicit" virtual bidding is wholly inappropriate, is subject to gaming, and endangers reliable operations. The ISO recommends that only explicit virtual bidding be allowed. However, the ISO believes that even explicit virtual bidding is inappropriate for the ancillary services markets. Finally, the ISO recommends that the Commission not mandate that ITPs initially permit explicit virtual bidding when they commence implementation of an integrated forward market. The ISO believes that it is more prudent to wait until the ITP has established and has gained experience operating a forward energy market.

3. Post Day-Ahead Unit Commitment

The NOPR proposes that each ITP facilitate a post-day-ahead unit commitment procedure whereby the ITP can commit sufficient resources to satisfy its next-day forecast load, plus reserves. The product and process outlined by the Commission in the NOPR are

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8 The ISO recognizes that LMP may cause equity concerns for certain market participants and submits that such concerns should be accommodated, at least for some transition period.

substantially the same as the Residual Unit Commitment ("RUC") process proposed by the ISO in its MD02 filing.

The ISO supports the need for a post-day-ahead "reliability" commitment and agrees "in concept" with the Commission's proposal. Specifically, the ISO supports a means for an ITP to commit the resources necessary to satisfy ITP-forecasted day-ahead load. For example, to the extent that participants in the ITP's markets fail to self-schedule a sufficient amount of resources to satisfy the ITP's aggregate system-wide load forecast, the ITP must be able to ensure that there are sufficient resources committed to be on-line to serve the anticipated load. Absent this ability, the ITP will be prone to the exercise of market power in real-time (assuming that real-time supply is available) or, even worse, the ITP may have to violate operational reliability requirements or be forced to curtail load – none of which are attractive options from a reliability or cost perspective.

4. Post-Day-Ahead Scheduling Flexibility

The NOPR proposes a two-settlement system wherein market participants submit day-ahead schedules that are financially binding and then any schedule changes made subsequent to the day-ahead are settled at the real-time price. Since start-up, the ISO has operated under a three-settlement system. Under this approach, market participants have the ability to submit both day-ahead and hour-ahead schedules to the ISO, both of which are financially binding with the hour-ahead being an incremental settlement market with respect to the day-ahead settlement).

The ISO, with the support of the majority of its market participants, believes there are significant benefits to conducting an Hour-Ahead market as well as a Day-Ahead market The Hour-Ahead market allows market participants the opportunity to utilize more recent information to adjust schedules and arrange new deals after the close of the day-ahead market but much closer to real time and before being subjected to variable imbalance energy prices While a two-settlement system may be easier to implement and administer, a three-settlement system similar to that already in place in the ISO's markets is more compatible with existing practices in the West, where market participants have always relied on the ability to make schedule adjustments up to real time and do not want to be financially exposed to unknown (*i.e., ex post*) real time prices. Therefore, the ISO recommends that the Commission permit each ITP to determine what type of settlement system is appropriate for its region.

C. The Real-time Market

The NOPR provides for the creation of a real-time market wherein an ITP performs Security-Constrained Economic Dispatch ("SCED"). The SCED program would simultaneously dispatch and price real-time energy based on the detailed transmission network model[9] and will establish a single price for energy/transmission in the real-time market. The SCED program, used in combination with a full network model, will establish LMP or nodal prices. The NOPR also proposes an *ex post* pricing regime wherein suppliers are paid a price based on their actual response to dispatch instructions.

The ISO supports the Commission's proposed structure for the real-time energy market. With certain detailed exceptions, the approach outlined by the Commission is substantially similar to that proposed by the ISO in its MD02 The ISO notes that a design that simultaneously procures (dispatches and prices) all real-time energy will reduce the need for operator discretion and for the operator to take non-transparent actions in real-time (Out-Of-Market/Out-Of-Sequence transactions) In addition, by establishing nodal prices for generators, ITPs will establish more accurate price signals. This will better enable generators to take

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9 A full network model is a detailed representation of the transmission system that reflects all measurable transmission constraints The full network model is in contrast to the simplified model the ISO uses today, which only models and prices Inter-Zonal transmission constraints (the large constraints between zones and the interconnections with other control areas) and generally ignores Intra-Zonal congestion In its MD02 proposal, the ISO advocates moving to the use of a full network model Use of such a model (and pricing derived from it) will eliminate a known deficiency in the ISO's existing system (*i e* , pricing Inter-Zonal Congestion but not Intra-Zonal Congestion), thereby reducing potential gaming and manipulation

actions based on price signals that are aligned with reliable system operation. Finally, the ISO believes that the optimization program will achieve a least bid-cost dispatch of system resources based on known transmission constraints, thereby increasing the efficiency of real-time operations. The ISO also supports *ex post* pricing, *i.e.*, pricing and settlement based on actual performance in response to dispatch instructions. However, *ex post* pricing would not eliminate the need for penalties for uninstructed deviations. In the absence of such incentives, physical withholding (in the form of non-compliance with dispatch instructions) can prevail in real-time, and the ISO would be forced to dispatch higher-cost units

D. Transition To A Single Tariff

The Commission inquires whether there is a need to include limitation of liability provisions in the *pro forma* tariff and, if so, what liability protections should be included. It is imperative that the Commission approves adequate limitations on the liability of ITPs (including market monitoring units) that provide interstate transmission and wholesale market services pursuant to tariffs that are subject to the Commission's jurisdiction. Entities such as the ISO have no state tariff/law liability protections and, therefore, need such protections in their tariffs It is especially important that the Commission limit the liability of ITPs for negligent acts. Absent such meaningful limitation of liability provisions, ITPs could be exposed to damage awards of catastrophic proportions. Absent adequate limitations on liability, ITPs – including the ISO – are facing sky-rocketing insurance costs, which costs are ultimately passed through to electricity consumers Limitation of liability provisions, including a gross negligence standard, will result in lower insurance rates, enhance ITPs' ability to raise capital and eliminate any "chill" on ITP market monitoring and compliance activities. Further, it will shift the risks to those market participants that are better positioned to deal with such risks.

E. Market Monitoring

The NOPR provides that market monitoring shall be conducted on an ongoing basis by a market monitoring unit ("MMU") that is autonomous of the ITP's management and market participants The NOPR states that the MMU should report directly to the Commission and the ITP's Board. The NOPR states that the MMU would identify necessary rule changes and identify circumstances that may require additional market power mitigation.

The ISO believes that the Commission's proposal is problematic. While the ISO understands the Commission's need to have access to data in order to monitor markets effectively, the ISO opposes an "autonomous" MMU reporting directly to the Commission if such an "autonomous" entity is comprised of ITP employees. MMU employees cannot simultaneously serve as "agents" for the Commission and as employees for the ITP. Such an arrangement would create an inevitable and irreconcilable conflict for the employees, *i.e.*, employees paid by the ITP but reporting directly to the ITP's regulator. This conflict is further complicated by the Commission's consideration of charging the MMU with monitoring and evaluating the operations and actions of the ITP. The ISO believes that the Commission's proposal would put ITP employees who are part of the MMU in an extremely difficult position.

Furthermore, at least for the ISO, personnel employed in the market monitoring unit, who have been retained because of their expertise in economics and markets, are needed by the ITP to provide broad economic advice to management, formulate proposals and assist in regulatory filings. If the Commission determines that the MMU must be constituted of ITP employees, but report directly to the Commission, such employees would necessarily be conflicted in their roles and responsibilities As a result, the ITP would have to go out and hire additional employees to perform functions currently provided by the MMU. In other words, the ITP would be hiring employees to perform duplicative work. This will cause ITP costs to increase unnecessarily.

The ISO does not object to a truly autonomous entity (such as an outside auditor or the ISO's existing Market Surveillance Committee) reporting directly to the Commission and advising the ITP's board. However, such entity can have only an advisory role because the authority to determine the content of Section 205 filings resides solely with the ITP. For example, in an effort to ensure independent market monitoring, the ISO contracts with its Market Surveillance Committee ("MSC") which is an independent advisory group of industry experts. To ensure independence, none of its members are affiliated with or have any financial interest in any market participant. Their charter allows them to suggest changes in rules and protocols or recommend sanctions or penalties directly to the ISO Governing Board and the Commission. The functions of the MSC include providing an independent review of market performance and market power problems, developing a record of structural problems and proposing corrective actions, and reviewing ISO rule changes, penalties, and sanctions

Finally, the ISO supports the efforts of the SSG-WI to develop a West-wide market monitoring function Whether that function ultimately resides in a single market monitor for the West or a coordinating body of monitors that serves that same function, the ISO supports the need for effective and timely monitoring of the entire Western market. Furthermore, if the SSG-WI is successful the ISO supports the retention of local (*i.e.*, individual ITP) market monitoring units that report to management because s they are needed to perform economic and market analysis and assist in the preparation of Section 205 filings. Moreover, to the extent there is a super-regional MMU, a more "local" market monitoring unit would be needed to focus on, and have expertise in, sub-regional market issues and be able to identify problems in the particular sub region

F. Market Power Mitigation

As proposed in the NOPR, the centerpiece of the Commission's market power mitigation framework is resource adequacy. The Commission reasons that by expanding resource alternatives (adding more supply/demand), the Commission will mitigate the ability of suppliers to exercise market power. In addition, to mitigate *local* market power, the Commission proposes that all generators dispatched by an ITP enter into participating generator agreements ("PGAs") that include provisions to mitigate local market power. The Commission invites comments on proposed triggers. Finally, the NOPR requests comments on whether (1) a safety-net bid cap should be uniform across an interconnection (*i.e.*, one in the East and one in the West) and (2) what triggers are appropriate for mechanisms that would apply in conditions in which resources can exercise market power "temporarily."

The ISO generally agrees that resource adequacy (in particular, forward contracting) is an important means to mitigate the exercise of market power With respect to local market power mitigation, the ISO agrees that a PGA-approach may be workable. However, as opposed to specifying the explicit conditions under which a resource's bids would be mitigated, the ISO's believes the simplest and most appropriate approach is to identify non-competitive regions *a priori* and anytime bids are taken out of sequence within a non-competitive region they are mitigated to a predetermined level – preferably cost-based. This is the approach currently applied by PJM. The ISO also might support an AMP-based approach to local market power mitigation such as the approach adopted by the New York ISO, albeit with tighter conduct and impact thresholds than those used for system-wide market power mitigation

The ISO supports the development and imposition of uniform interconnection-wide bid caps. A uniform bid cap is essential in order to avoid "megawatt laundering" and to ensure efficient arbitrage. The ISO submits that it is imperative that the level of the cap be based on an assessment of the extent to which markets in a region are workably competitive A $1,000 MWh bid cap – which is in place in Eastern markets – is wholly inappropriate in the West because of the low reserve margins that exist in the West, as well as the supply demand imbalance, inadequate transmission infrastructure and existing market dysfunctions in California

The ISO also supports implementation of two distinct market power mitigation measures: one that would apply to "unanticipated" market conditions that provide suppliers with the opportunity and the incentive to exercise market power on a temporary basis; and one that would apply to "sustained" market conditions that would enable suppliers to exercise market power for a prolonged period. One mechanism that can address "temporary" market power conditions is the Automatic Mitigation Procedures ("AMP") that are in place in New York and California. However, the ISO believes that the AMP thresholds must be stricter than those previously approved by the Commission for California. The ISO disagrees with the Commission that AMP-like mechanisms should be suspended once competitive conditions are restored. Because system conditions are dynamic, protections must be in place at all times

Finally, in regions like the West that rely on hydro generation – which can be unavailable for prolonged periods if drought conditions persist -- the Commission should establish a separate "conditional" market power mitigation mechanism that would be triggered during periods in which generators can exercise market power for a prolonged period (due to drought conditions, unanticipated load growth or prolonged supply-demand imbalance).

G. ITP Governance

The NOPR provides that an ITP must be independent of all market participants. In addition, the NOPR outlines the features of an ITP's governance structure and process by which the ITP's Board members should be selected.

The Commission's and the ISO's views on this matter are clear The ISO submits that the Commission does not have authority under the Federal Power Act to dictate the internal corporate governance of a public utility.

H. Regional State Advisory Committees

The NOPR proposes to establish Regional State Advisory Committees ("RSACs") to provide a formal role for state representatives to participate on an ongoing basis in the decision-making process of ITPs The NOPR states that, "The specifics of how this advisory committee would be formed and operate would be decided on a regional basis." The Commission states that an RSAC would seek regional solutions to the following issues

a. Resource Adequacy;

b. Transmission planning, expansion;

c. Rate design and revenue requirements;

d. Market power and market monitoring;

e. Demand response and load management,

f. Distributed generation and interconnection policies;

g. Energy efficiency and environmental issues;

h RTO management and budget review

The ISO supports "active engagement" by state policymakers in the ITP process In addition, the ISO agrees with the Commission that the structure and function of any RSAC-type entity be decided on an ITP-regional basis.

The ISO acknowledges that states have a legitimate, if not primary role, in many of the functions/subject matters identified above The ISO states that, with respect to each of these identified areas, there exists today mechanisms through which state and other participants can provide input to an ITP and that a formal role (through an advisory committee) may be built upon existing forums For example, the ISO's existing stakeholder and Board processes are open to the public and any entity can provide input, or recommend actions Moreover, with respect to ISO costs and budget, the ISO conducts an open budget process and, charges related to ISO cost recovery must be filed at the Commission and are vetted through the regulatory process. The ISO believes that it is appropriate to facilitate state/local interaction regarding these matters and to fashion a structure for ITP-state/local coordination that best fits each region.

Finally, in order to facilitate better super-regional coordination, the ISO recommends that the Commission rely on existing forums to further such efforts Specifically, the ISO notes that both CREPC and SSG-WI currently facilitate inter-regional discussions regarding many of the issues identified above The ISO supports those efforts and requests that the Commission utilize those structures to promote increased inter-regional coordination

III. The New Transmission Service (PP 136-164)

The ISO generally supports the Commission's proposed standard market design that offers Network Access Service to all of an ITP's customers, offers CRRs for financial protection for loads for congestion costs and manages congestion through LMP under a single set of rules. Security constrained, bid-based spot markets are compatible with bilateral transactions that are scheduled through the ITP's markets and face congestion charges that can be hedged with a commensurate amount of CRRs in specific receipt/delivery point combinations. Customers willing to pay the congestion costs associated with a particular transaction in a LMP system can be provided transmission service, thereby eliminating the distinction between firm and non-firm service. Comments regarding specific proposals in the NOPR are set forth below

A. Designation of Network Resources and Loads (P 153)

The Commission requests comments on whether designating network resources and loads is necessary for Network Access Service, particularly with respect to performing the integration of resources and loads. The Commission inquires whether it is necessary for the ITP to request information beyond the identity of and contact information for the customer, service term and commencement date, and receipt and delivery points for the requested service. In particular, the Commission asks whether the ITP needs to collect for each service request (but not for each transaction) the location and characteristics of the generation serving the load, detailed descriptions of the load and the customer's transmission system and owned generation.

The ISO submits that designating specific network resources and loads should not be required for Network Access Service, but it should be necessary to specify the location of the sources and sinks, including internal generation serving internal load, and the transmission system usage pattern for Network Access Service regardless of the type of market participant.[10]

For the ITP to determine simultaneous feasibility of Network Service Rights unambiguously, the information should include not only the location of the sources and the sinks (points of delivery and receipt), but also the preferred transmission usage pattern (relative ratios of resource schedules), and maximum/minimum injection/withdrawal levels in case the primary (preferred) patterns are not simultaneously feasible.

B. Reconfiguration of CRRs (P 156)

Under the proposed Network Access Service, customers can access any point simply by requesting it through the day-ahead scheduling process or real-time transactions. To the extent a customer desires to avoid the cost of congestion for the transaction, it can retain its existing CRRs and acquire additional CRRs for its new receipt and delivery points through an auction or the secondary market Alternatively, the customer could request a "reconfiguration" of the CRRs it holds, *i e.*, the customer could turn in the CRRs for the old receipt and/or delivery point and request CRRs for the new receipt and/or delivery point The Commission seeks comment regarding the MW quantity of reconfigured CRRs that the customer should be entitled to receive.

For an ITP constantly to be evaluating requests for "reconfigured" CRRs would be burdensome and problematical because the ITP would need to conduct a simultaneous feasibility test on the network to ensure compatibility. In addition, the value of a CRR could be changed after its sale if requests for reconfiguration were accepted. The ISO has proposed periodic monthly auctions of "excess" CRRs (*i.e.*, CRRs remaining after allocating CRRs to

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[10] Under a LMP system for allocating scarce transmission capacity, a direct link between sources (*i.e* , resources) and sinks (*i.e.*, loads) is not necessary for Network Access Service Self schedules and bilateral transactions can be linked and service provided as long customers are willing to pay the congestion costs

LSEs. This could be an avenue for a customer to release and acquire additional CRRs. Network Access Service allows a customer to inject or withdraw energy at any node in the network and to protect transactions from congestion costs through the acquisition of CRRs. Thus, Network Access Service promotes non-discriminatory use of the transmission system.

C. Scheduling Priority for CRR Holders (P159)

The Commission proposes that, to the extent the ITP is unable to schedule all requests for service made through the day-ahead scheduling process, those customers with CRRs for their requested receipt point-delivery point combinations should be scheduled first The Commission seeks comment as to whether such scheduling priority is appropriate.

In its May 1, 2002 MD02 Filing in Docket No. ER02-1656, the ISO proposed to retain its existing day-ahead scheduling priority for point-to-point CRR holders.[11] Specifically, under Section 9.7.1 of the ISO Tariff, point-to-point CRR holders have a scheduling priority in the day-ahead market, which means that balanced schedules submitted in the day-ahead market with the appropriate point-to-point CRRs associated will have priority against curtailment over other non-existing transmission contract schedules. Under the ISO's design schedules with existing transmission contracts have first priority, then schedules with point-to-point CRRs come next. This priority for schedules with CRRs does not extend beyond Day-Ahead Thus, CRRs not used with preferred schedules in the Day-Ahead market for any hour have no scheduling priority in the Hour Ahead market

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[11] In its Order accepting the ISO's existing FTR scheme, the Commission rejected arguments that the scheduling priority should be eliminated. *California Independent System Operator Corporation*, 87 FERC ¶ 61,143 at 61,573 (1999) In particular, the Commission rejected arguments that the scheduling priority would reduce the incentive of FTR holders to submit adjustment bids and reduce the ISO's ability to manage congestion *Id.* The Commission noted that the scheduling priority does not affect the congestion management situation in any significant way because it merely serves as a tiebreaker when there are not price differentials in the Adjustment Bids or when there are insufficient Adjustment Bids

The MD02 proposal does not alter this concept of scheduling priority. Consistent with its prior decision, the Commission should not eliminate the scheduling priority

The issue of the appropriateness of a CRR scheduling priority may be one where regional variations should be accommodated. The ISO submits that point-to-point CRR holders should have a scheduling priority In that regard, the impact of the ISO's proposed scheduling priority is quite minimal, because it only provides a tiebreaker mechanism for those situations where submitted bids are insufficient to manage congestion. The ISO does not believe that a CRR scheduling priority would undermine the benefits of having a single transmission service for all customers. All customers using the transmission system for delivery from a specific point to another specific point would be paying the same congestion usage price. However, those with CRRs have already directly or indirectly paid an additional amount to obtain the CRRs; giving them scheduling priority is an equitable compensation

D. Penalties for Failure to Curtail (P 160)

The Commission proposes that an ITP can assess a penalty for failure to curtail if a transmission customer fails to curtail after reasonable notice. The proposed penalty would be the locational marginal price plus $1000 per MWh. The Commission notes that it has approved a minimum notice period of ten minutes if the curtailment is for reliability purposes and requests comment on whether the Commission should continue this practice.

In prior orders, the Commission has approved penalties for a transmission customer's failure to curtail after reasonable notice. *See, e.g., Sierra Pacific Power Company, et al.,* 101 FERC ¶ 61,201(2002); *Southwest Power Pool, Inc ,* 86 FERC ¶ 61,090 (1999), *Allegheny Power Systems, et al.* 80 FERC ¶ 61,143 at 61,545-46 (1997), *order on reh'g,* 85 FERC ¶ 61,325 (1998), *see also Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats & Regs., ¶ 31,036 at 31,749 (1996). Such penalties are appropriate because system reliability can be threatened if customers fail to curtail when requested.

The Commission should allow the minimum notice period to be altered by agreement of NAESB or the various ITPs in a region. The Commission also should clarify that the penalties would apply to the entity that communicates directly with the ITP.

E. Forum for the Sale of CRRs (P 163)

The Commission seeks comment as to whether all CRRs must be sold through the OASIS, or whether some bilateral sales may be made and then reported through OASIS after the sale.

The ISO supports allowing CRR sales to be made outside OASIS. In fact, the ISO's existing FTR Secondary Registration System ("SRS") can act like a virtual "bulletin board" for such sales. However, the ISO does not itself intend to facilitate CRR trades other than through its normal auction process. However, to the extent that bilateral sales outside OASIS are permitted, they should be accurately reported (with stiff penalties and sanctions for fraudulent reporting) on the ISO's SRS Moreover, the possibility of imposing position limits (if there is evidence of gaming or exercise of market power through possession of excessive amounts of CRRs) should not be foreclosed.

IV. Transmission Pricing (PP 167-202)

The ISO supports the Commission's general views on transmission pricing. Loads are the primary source for recovery of a Transmission Owner's transmission revenue requirement through payment of access charges. The ISO also believes that rate "pancaking" should be eliminated. The ISO's MD02 Proposal reflects these core principles of transmission pricing.

A. Recovery of Embedded Costs (P 172)

The Commission seeks comment on the treatment of existing customers taking long-term firm Point-to-Point Transmission service that are not LSEs. The Commission believes that it would be inequitable for customers to receive an initial allocation of CRRs unless they also pay a share of transmission embedded costs and vice-versa. The Commission states that one option is for these customers to continue paying their embedded cost charges in exchange for receiving CRRs that reflect their current levels of Point-to-Point Transmission Service The second option is to eliminate the access charges for these customers while also allocating no CRRs to them

The ISO supports the first option. However, the ISO is concerned that these customers may be unjustly enriched, or the number of products the ITP is required to retain could be prohibitive. Some existing contracts do not fully recover the transmission revenue requirements of the transmission owner, and the CRR product may be more firm or for a different period of time than the existing contract If the contract right can be easily converted, that should ease integration into the new market design

B. CRRs Following Load (P 173)

The Commission raises the issue of the appropriate treatment of LSEs in retail open access states that attract load away from the traditional utility supplier and seeks comment regarding the extent to which new LSEs should receive an allocation of the CRRs held by the customer's former LSE in areas where there is no ATC for additional CRRs.

The ISO supports the rule that CRRs should follow the load (*i e.*, when a customer switches to a new LSE, its CRRs should be transferred to the new LSE). The ISO's MD02 proposal is consistent with this approach. However, there is a question as to how to allocate CRRs to existing contracts and new load (load growth). In some instances, existing contracts incorporated increased usage prior to the usage actually taking place. The ISO's MD02 proposal utilizes historical usage, but determining that level may be difficult. If new load is required to pay the Transmission Access Charge, such load deserves to receive a proportionate share of the CRRs, in which case CRRs could be "diluted" for all load. In addition, if the ITP infrastructure is insufficient, CRRs could be greater than the physical transfer capability of the transmission path.

C. License Plate Rates (P 174)

The Commission proposes to permit the use of license plate rates However, the Commission seeks comment as to whether it should retain license plate ratemaking only for a transitional period and, at some later date, require that all regions have postage stamp rates. The Commission also asks whether, upon the recommendation of a Regional State Advisory Committee, it should accept an embedded cost recovery mechanism for the region that may vary from neighboring regions.

The ISO supports the Commission's recommendation to defer to regional authorities or, more broadly, to allow regional variation. Each developed or developing ITP has carefully crafted a pricing proposal that works for the entities within that ITP's region. The ISO believes that mandating a standard approach may upset the balance of benefits and burdens inherent in each ITP's proposal. The nature and cost of systems vary across regions and within regions. Market participants within a particular region are in the best position to determine the pricing options that work best for them.

Consistent with that postion the ISO, as a member of the Seams Steering Group – Western Interconnection ("SSG-WI"), is currently engaged in discussions to reduce or eliminate barriers to trade – including pancacked transmission charges – between the three proposed Western RTOs, while preserving each RTO's discretion regarding its own internal transmission pricing arrangements. The ISO recommends that the Commission defer to such inter-regional forums on this issue.

D. Postage Stamp Rates (P 178)

The Commission seeks comment on whether all customers should be charged the same transmission rate either upon implementation of SMD or after a reasonable transition period of four years.

Consistent with the discussion above, the ISO does not recommend that the Commission establish a generic embedded-cost transmission pricing policy. Rather, the Commission should defer to each region to develop a proposal that works best for that region.

As the Commission is aware, the ISO initially commenced operations with a license plate methodology and subsequently filed to transition to a postage stamp rate. As further detailed in Amendment Nos. 27, 34 and 45 to the ISO Tariff, the ISO's proposal reflects a delicate balancing of the risks/rewards of moving to a postage stamp methodology and the time frame for doing so. The ISO proposal implements a full postage stamp methodology for high voltage transmission facilities (200kV and above) over a full ten years. The ISO's access charge transition has already begun and, if allowed to continue, will be completed in 2010 Under the ISO's proposal, revenue requirements for low voltage transmission facilities would still be recovered on a license plate basis. This proposed transitional Transmission Access Charge methodology was filed in Docket No. ER00-2019-000. A hearing on this proposal has been scheduled for later this year.

E. Recognition of Import/Export Quantities (P 185)

The Commission proposes to establish a mechanism that recognizes import/export quantities in establishing the revenue requirement to be recovered through the ITP's access charge One approach is to have a portion of the "source" ITP's revenue requirement allocated across all of the "sink" ITP's transmission customers (an uplift). A second approach is for all net importing ITP transmission customers to cover the cost of transmitting on a neighboring ITP.

As the Commission is aware, the ISO, as a member of SSG-WI, is engaged in discussions with representatives of the other proposed RTOs in the West -- RTO West and Westconnect -- regarding potential "price reciprocity" options among and between the proposed RTOs. The focus of these discussions is the development of potential options for reducing transaction-based barriers to trade between the RTOs. To date, and as further detailed in the January 8, 2003, "Report of the California ISO, RTO West Filing Utilities and the WestConnect

Applicants Concerning Activities of the Seams Steering Group—Western Interconnection" ("SSG-WI Filing") in Docket Nos ER02-1656, *et al.* the SSG-WI Price Reciprocity Work Group has identified four potential options for achieving some form of price reciprocity. One option under consideration by the work group is a waiver of all embedded-transmission-cost related export fees for transactions between approved RTOs. The ISO originally offered and outlined such a proposal in its June 1, 2001 RTO filing. In addition, the work group is also actively considering another option that provides for the RTOs to waive transaction-based "export" fees that apply to all inter-regional (*i.e.*, between RTOs) transactions and for the RTOs to recover any "lost" revenues through periodic (*e.g.*, annually) "transfer" payments between the RTOs. Under this proposal, each of the individual RTOs would decide how to allocate revenues/costs related to the transfer payments to owners/users of their respective systems The ISO believes that SSG-WI is the appropriate forum for addressing these issues and developing a consensus Western recommendation regarding price reciprocity With respect to each RTO's ultimate allocation of the costs/revenues of any transfer payments or lost revenues, the ISO recommends that the Commission not prescribe a standard approach, but instead allow the ITP, state representatives, transmission owners and market participants in each region develop a consensus proposal.

F. Allocation of Inter-Regional Costs (P 188)

The Commission seeks comment on whether there should be a uniform cost allocation of inter-regional costs among all zones within an Independent Transmission Provider's system. Under this approach, inter-regional transfers could be netted out between zones within neighboring ITPs. In this way costs would be assigned to all customers within the import zone and the revenues would be returned to the export zone.

As described above, the ISO supports the SSG-WI effort to develop options for price reciprocity and recommends that the Commission permit each RTO to develop individual proposals for how to allocate costs and revenues within its system.

G. Assignment of CRRs to Importing Region (P 189)

The Commission proposes to treat inter- and intra-regional transmission pricing the same. As indicated above, the Commission also proposes to allocate CRRs (or the revenues from the auction of such rights) to customers within a region who pay the access charge. The Commission states that there should be a similar result for inter-regional transactions where customers in one region are paying a portion of the embedded costs of another region. The Commission seeks comment on how to assign CRRs to the customers of the importing region.

The ISO believes that, in order to be consistent in the assignment of CRRs, all net importing ITP customers that are paying a portion of the costs of transmitting power on a neighboring ITP should receive CRRs in proportion to their historic use of import power. That is, to the extent a customer in one ITP's area has an arrangement for the delivery of power from another ITP's area, those arrangements should be allocated CRRs consistent with their historic usage. To the extent that this is a new arrangement (usage), the importing entity should arrange to acquire (through auction) the requisite amount of CRRs.

H. Pricing of Parallel Path Flows (P 190)

To the extent the Commission adopts a true-up methodology for recovering the costs of through-and-out services, the Commission queries whether there should a similar pricing methodology be applied to parallel path flows. Historically, the West has managed inadvertent loop flow through established WECC procedures. Specifically, WECC adopted, and the Commission approved, the WECC Unscheduled Flow Mitigation Procedure that relies on the use of selected phase-shifter devices located throughout the West. To date, those reliability-based procedures provide that entities using their phase-shifters to mitigate real-time transmission line overloads receive cost-based compensation for operating the selected facilities. Thus, the unscheduled flows or parallel path flows were not managed in accordance with bid-based congestion management protocols However, as further detailed in the January 8, 2003 SSG-WI Filing, in 2001 WECC developed a report on the use of bid-based mechanisms to manage phase shifter operation in the West. In addition, SSG-WI has formed a "Congestion Management Alignment Work Group" whose specific assignment is to determine whether and how the three proposed RTOs' congestion management systems need to be and can be made compatible. To that end, the SSG-WI congestion management work group intends to build off of the previous work done by WECC and address the larger issue of parallel path flow management throughout the West. The ISO supports the SSG-WI effort as the appropriate forum for addressing this issue.

I. Recovery of Transmission Expansion Costs (P 202)

The Commission recognizes that the existing transmission grid has fallen far behind the demands that have been placed on it. The Commission states that its goal is to remove any impediments to recovering the costs of transmission expansions so that necessary upgrades are built now. The Commission believes that a more precise matching of beneficiaries and cost recovery responsibility would encourage greater regional cooperation to get needed facilities sited and constructed. The Commission states that its preference is to allow recovery of expansion costs through participant funding, *i.e* , those who benefit from a particular project (such as a generator building to export power or load building to reduce congestion) pay for the project. With respect to expansions on facilities at voltages of 138kV or higher, costs would be recovered on a region-wide basis. With respect to expansions on facilities of voltages below 138kV, costs would be allocated to the appropriate sub-region. The Commission seeks comment as to whether these pricing proposals are appropriate to meet the Commission's goal of expediting needed infrastructure investment or whether some other method would be more effective.

The ISO fully supports the need for and the Commission's focus on infrastructure expansion. In particular, the ISO agrees that the focus of such expansion efforts should be on the high-voltage "interstate" transmission system to facilitate the development of competitive wholesale electricity markets on a region-wide basis. Moreover, the ISO believes that proactive transmission expansion efforts are necessary to alleviate historical transmission constraints that complicate efforts to transition to accurate locational marginal pricing (LMP). While the ISO fully supports the use and application of LMP as the basis for real-time dispatch and to allocate and price transmission in the forward markets, the ISO views such a pricing regime to be "necessary but not sufficient" as an incentive for transmission infrastructure investment. In order to achieve adequate investment in transmission, the ISO agrees with the Commission that an appropriately tailored transmission pricing policy, along with a coordinated regional planning and expansion process, is necessary.

As to the questions specifically posed by the Commission, the ISO supports the Commission's proposal to allocate the cost of high-voltage transmission expansions grid-wide and to allocate the cost of lower-voltage expansions to the specific sub-regions that benefits from such investments. The ISO believes that this approach is consistent with the ISO's filed Transmission Access Charge proposal (*see* Docket No ER00-2019). As discussed above, the ISO has proposed to recover costs on a postage stamp basis for facilities rated at 200 kV and above after a phase in period Costs for low voltage facilities would be recovered on a license plate methodology basis.

With respect to participant funding, the ISO agrees that, if an entity engages in true participant funding, *i.e.*, the entity bears the costs of a transmission grid expansion and does not seek recovery of such costs through the access charge, the entity should be given CRRs for new capacity associated with the expansion If costs for new facilities are recovered through the access charge, then the CRRs should go to the loads that are paying the costs.

Notwithstanding the Commission's desire for expeditious expansion of the transmission system, the ISO does not support the adoption of policies that sacrifice efficient expansion of the system for the sole purpose of facilitating transmission expansion. The ISO is concerned that the Commission will adopt generator interconnection standards that could lead to inefficient expansion of the system. If the Commission permits a generator, or any entity for that matter, to fund transmission expansions and then receive a direct credit, the result may be that all users pay for unnecessary expansions [12] For example, a generator may decide, for a variety of reasons, to locate in an area that requires significant transmission upgrades. As the ISO understands them, under the Commission's proposed policies, that generator could initially fund the upgrade but receive a credit equal to its investment over a short five-year time period. Under these circumstances, all users may be asked to pay the cost of that expansion even though most users do not benefit from the upgrade. More importantly, the generator could have chosen a more beneficial (from a system perspective) location that would not have required substantial upgrades.

Finally, in order to further greater inter-regional coordination and support for necessary transmission expansion, the ISO notes that SSG-WI has created a transmission planning work group whose primary focus is the development of a regional transmission planning process that will promote economic expansion of the Western grid. The ISO strongly supports that effort. The ISO believes the SSG-WI forum is the proper forum for addressing, and developing a Western consensus regarding regional transmission planning and expansion. The SSG-WI effort is designed to complement the reliability-focused WECC transmission planning/coordination process already in place. Together, through these forums and processes, the West can develop proposals for the reasoned and economic expansion of the Western transmission system.

V. The New Congestion Management System (PP 203-255)

The ISO supports the Commission's view that the ITP should manage congestion through a system of LMP and CRRs. As explained earlier in these comments, an LMP-based system is necessary to support one of an ITP's core functions – that of supporting reliable

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12 This is in contrast to a situation where a generator funds a transmission upgrade and receives CRRs as compensation for its investment, i e , does not seek or receive direct cost recovery.

system operation. To achieve that objective, however, the Commission should allow adequate flexibility to account for regional variations – variations that are based on the physical realities of the regional grid and the specific nature of the resources in that region.

A. Locational Marginal Pricing

1. Changes In Service In Day-Ahead (P 209)

The Commission proposes that any changes a customer wants to make to the transmission service it has scheduled in the Day Ahead market must be accomplished in the Real Time market at Real-Time prices that may be different than the Day-Ahead prices. In other words, market participants can make *schedule* changes between Day-Ahead and Real-Time, but any schedule changes made subsequent to the submission and acceptance of day-ahead schedules are *settled* (*i.e.*, priced) based on Real-Time prices.

The ISO, with the support of the majority of its market participants, believes there are significant benefits to conducting an Hour-Ahead market as well as a Day-Ahead market. The Hour-Ahead market allows market participants the opportunity to utilize more recent information to adjust schedules and arrange new deals after the close of the Day-Ahead market but much closer to real time and before being subjected to variable imbalance energy prices. While the two-settlement system described by the Commission may be easier to implement and administer, a three-settlement system similar to that already in place in the ISO's markets is more compatible with existing practices in the West, where market participants have always relied on the ability to make schedule adjustments up to real time and do not want to be financially exposed to unknown (*i.e., ex post*) real time prices. The ISO believes that the Commission should permit each ITP to determine what is appropriate for its region, based in large part on the desire of its market participants, and should not mandate that a two-settlement system be adopted.

2. Accommodation of Regional Requirements (P 211)

The NOPR lays out the general framework and the basic rules for LMP based on the best practices the Commission has seen. However, the Commission recognizes that in certain regions there may need to be additional rules or changes to accommodate specific regional requirements and seeks comment on how best to recognize this need for regional variation.

The best vehicle for allowing specific regional variation is to engage market operators, the ITP, or ISO, and market participants in an extensive dialogue to determine what market functionality and requirements work best for that region based on their understanding of markets in the region. The ISO is currently engaged in such discussions through its involvement in the SSG-WI effort. In addition, the ISO will continue to engage in other forums, such as WECC, the Western Governors Association ("WGA"), the Committee of Regional Electric Power Cooperation ("CREPC") and others. The ISO requests that the Commission to defer to these forums to develop region-wide and appropriate market functionality and rules.

3. Accommodation of Hydro Facilities (P 216)

The Commission proposes to accommodate the special features of hydro facilities in the NOPR. Specifically, hydro facilities can request that the ITP schedule the generator's energy budget over the highest priced hours of the day.

As a general matter, the ISO believes that an LMP-based system can accommodate and be made compatible with hydropower operations However, the ISOs general view on this matter is not intended in any way to understate or diminish the difficulties that arise when addressing hydropower-related issues Hydropower operations are typically planned and optimized over long time periods (months or seasons) and do not fit neatly into the daily operations and market structure of an ITP Thus, optimizing the scheduling of a hydro system involves consideration of more factors than a daily energy budget and prices. For example, there may be a number of inter and intra-day constraints as well as inter-unit constraints (*e.g.* watershed management issues) to consider.

Recognizing the complexity (and contentious nature) of managing these issues, the ISO believes such considerations are better left to the unit owner. Requiring an ITP to schedule (*i.e.*, manage) hydropower operations on a daily basis would inappropriately expand the ITP's function and require an ITP to become directly involved in and impact the energy/financial management issues of market participants. The ISO believes this to be in conflict with the primary mission of an ITP.

However, recognizing the need to accommodate hydropower resources within the construct of an ITP's operations and market structure, the ISO is prepared to entertain advanced (*i.e.*, pre-day-ahead market) coordination and scheduling for hydropower resources In the NOPR, the Commission has already acknowledged the need for pre-day-ahead scheduling option. Such an option could be used to accommodate a hydropower resource's basic operating requirements. Moreover, if such resources are also able to submit to the ITP their advanced resource plans (*e.g.*, their operating plan for the upcoming season), the ITP and resource owner may be able to develop an advanced operating schedule that satisfies both the resource's operating constraints (water use) but also maximizes the value of the resource. This could be achieved by examining the ITP's historical publicly-available price and market performance data.

4. Treatment of Existing Contract Holders (P 218)

The Commission would not abrogate existing pre-Order No. 888 transmission contracts; customers holding these rights could continue their existing services under the contractual provisions. Thus, customers receiving transmission service under the Order No 888 *pro forma* tariff, as well as entities previously serving bundled retail load outside of the *pro forma* tariff, would receive CRRs to protect against congestion charges.

The ISO acknowledges the Commission's intent to honor all previously existing transmission contracts Such an approach, however, must be balanced with the need for a uniform set of rules and protocols for scheduling and using the transmission system. As the

ISO has repeatedly stated in filings to the Commission, having two sets of rules by which market participants can schedule and use the grid creates inefficiencies (and inequities) that undermine the efficient allocation and use of the grid. For example, because the ISO must reserve or set aside an existing transmission contract ("ETC") Rights holder's full contract rights, the ISO effectively sets aside capacity that other firm users cannot use and that, in many instances, the ETC rights holder does not end up using. As a result, the ISO frequently assesses, through application of its day-ahead scheduling and congestion management protocols, congestion costs on market participants procuring transmission service in the ISO markets even though not all transmission capacity on the applicable system elements is utilized.

In order to achieve the objective of one set of rules applicable to all users of the transmission system, the Commission must adopt policies and procedures that reduce an ETC rights holder's real or perceived risk to additional costs and that create incentives for conversion of existing contracts. The Commission has outlined certain approaches in the NOPR, as will be discussed *infra*, and the ISO does not oppose those measures. The challenge faced by both the Commission and the ISO is to make ETC Rights holders comfortable with the shift from a physical rights-based transmission paradigm to a financial rights-based transmission paradigm. To the extent that the Commission and ISO are successful in convincing the ETC rights holders that the financial/cost consequences can be the same under either approach, the greatest obstacle to converting existing contract rights to right in the new market structure will be addressed. To that end, the ISO agrees that ETC rights holders should be offered CRRs based on their recent historic usage of transmission (*i.e.*, the last 12 months). CRRs offer an effective hedge against unknown congestion costs and should ensure that ETC rights holders are not financially exposed to new charges

In order to provide further incentives for conversion, the ISO does not oppose the Commission's proposal to require the previous transmission providers to schedule all ETC-related transactions under the ITP's/ISO's new scheduling protocols and to assume any price differences that may arise as a result of the differing terms between the ETCs and the ITP's Tariff. Thus, the Commission's proposal to require all former transmission providers to take service under the ITP's tariff to satisfy their obligations under their preexisting contracts is a workable solution, as is the Commission's proposal that the previous transmission providers be able to recover such costs through their wholesale or retail rates, (subject to appropriate regulatory review). The ISO believes that this package of incentives to both the ETC rights holders and the previous transmission providers will enable each ITP to establish uniform scheduling and transmission pricing protocols for all users of the grid. This outcome should further the Commission's efforts to promote the efficient allocation of transmission service to those that value its use the most. The ISO supports further development of this approach. With respect to the ISO, the ISO recommends that such development occur in the context of finalizing the ISO's MD02 proposal.

5. Differing Market Designs In the West (P 219 and 220)

The Commission expresses concern about whether different market designs can be in place in the Northwest and the rest of the West The Commission asks for comments as to whether the entire West must have a common set of market rules to eliminate seams and prevent manipulation.

The ISO submits that SSG-WI is the appropriate forum to work toward resolution of seams issues and to identify those elements of the Western market that must be common and those that can be compatible. The SSG-WI has made progress to date regarding resolution of some of these issues. As detailed in the January 8 SSG-WI Filing, the ISO believes that SSG-WI has identified all relevant seams issues and has created the necessary forum(s) for their resolution.

More importantly, the ISO supports the policy of permitting regional variation in market design and structure. Regional variation is necessary to allow individual ITPs to structure their markets in a manner consistent with historical regional trading practices to support regional operating practices (*i.e.*, practices that may be a consequence differing types of resources and the physical nature of the systems involved). As acknowledged by the Commission, regions with a significant amount of hydroelectric resources may structure their markets, scheduling timelines, congestion products differently than those with a predominantly thermal-resource based system.

While standardization is important, it is probably more important to determine, in the first instance, what products and systems must be standardized to support a seamless market. The ISO applauds the Commission's efforts to raise this issue at a national level, but requests that the Commission allow sufficient time for each region to undertake such examination. As stated above, SSG-WI is attempting such an effort now. The ISO urges the Commission to support such efforts. In addition, the congestion management process must be designed and implemented in a manner that does not produce reliability concerns in real-time.

B. Virtual Bidding (P226)

The Commission proposes to require ITPs to permit buyers and sellers to submit purely financial bids, a feature that currently exists in PJM and the New York ISO

The issue of virtual bidding has been raised in the ISO's MD02 proceeding. The ISO's position is that virtual bidding should not be implemented until after an ITP has sufficient experience operating a forward energy market, let alone the creation of a robust real-time energy market with security constrained economic dispatch and locational marginal pricing The ISO does not currently operate a forward energy market and, under the ISO's MD02 implementation schedule, the ISO likely will not implement an integrated forward market until 2004.

As the Commission has indicated on numerous occasions, the ISO markets have been dysfunctional and marred by numerous problems. A stable, proven market still does not exist in California. The MD02 Comprehensive Market Redesign constitutes a major step toward remedying the problems that have plagued California, and the ISO's integrated forward market proposal represents a complete paradigm shift in the way the ISO and market participants do business. After relaxing the existing market separation rule, eliminating the balanced schedule requirement, and introducing Day-Ahead and Hour-Ahead Energy markets, the fundamental bidding, scheduling, pricing, and settlement of the market will change. The ISO believes it is appropriate to ensure that the forward markets are running properly before implementing any virtual bidding mechanism The other successful independent system operators did not implement virtual bidding initially when they implemented their Day-Ahead markets. The Commission should not require the ISO or other ITPs to do so either.

At a minimum, any virtual bidding mechanism must be explicit by requiring that virtual or purely financial bids be flagged (a model commonly referred to as "explicit virtual bidding"). The ISO notes that PJM and the New York ISO require that bidders explicitly identify virtual bids. The same requirement should apply in California in the event virtual bidding is implemented at some time in the future. This will allow the ISO's grid operators to distinguish real (*i.e.*, physical) bids from bids that are purely financial and will be liquidated in Hour-Ahead or in Real-Time Markets. When virtual bids are explicitly labeled as such, the ISO can make unit commitment decisions and take other actions necessary for reliable grid operations based on the knowledge of what is real and what is virtual. In other words, if grid operators can distinguish which supplies will be available in Real-Time and which supplies are financial and purely fictitious and not intended to be available, they can plan accordingly Failure to identify virtual bids clearly could cause ITP operators to scramble unnecessarily in Real-Time when supplies that were bid in the Day-Ahead – and that the ITP counted on being there – fail to show up. Obviously, this raises reliability concerns. If virtual bidding is to be permitted, it must be permitted only under a set of rules and procedures that will prevent any adverse impacts on reliable grid operations. Explicit virtual bidding in the energy markets is appropriate only after the ITP has experience operating a forward energy market.

The ISO believes that "implicit virtual bidding" – a practice in which virtual bids are not explicitly labeled as such – should be prohibited. As the Commission is well aware, implicit virtual bidding can created significant reliability problems for grid operators. If virtual bidding is permitted, there is no legitimate reason why a bidder should object to flagging a bid as virtual unless the bidder is seeking to game the system by misrepresenting its intent. The ISO also believes that implicit virtual bidding runs afoul of the proposed requirement in the NOPR that market participants provide factually accurate information to the independent transmission provider or be subject to penalty. Finally, ISO does not believe it will ever be appropriate to allow any form of virtual bidding in any ancillary services markets, because ancillary service procurement is necessary for the ITP to ensure grid reliability, and the buying and selling of ancillary services should be a secondary component of the integrated forward markets

C. Congestion Revenue Rights (PP 235-255)

1. CRRs for Transmission Upgrades (P 238)

The Commission states that if an entity pays to construct new generation or transmission facilities that add transfer capability, and the costs of the upgrade are not rolled in, the entity would receive the CRRs associated with the new transfer capability The Commission notes that, in the past, the Commission has allowed credits for upgrades. The Commission inquires whether there is still a role for credits under Standard Market Design.

The ISO supports the allocation of CRRs to merchant transmission owners. Specifically, the ISO believes that if the owner of the facility will not earn a Commission-approved return on its investment through the ITP's Transmission Access Charge, the merchant transmission owner should receive CRRs associated with the increased transmission capacity, as determined by the ITP or the Western Electricity Coordinating Council or other appropriate party The ISO submits that such an approach should serve as an incentive for certain parties to build transmission facilities. For example, a merchant generator who creates new or upgrades existing transmission facilities to ensure delivery of its output will be able to preserve a scheduling priority and the right to congestion revenues even though other Scheduling Coordinator's energy may flow over those facilities.

In the MD02 proceeding, certain parties have argued that CRRs should be allocated to the project sponsor prior to the allocation of CRRs to LSEs. The ISO believes that the allocation of CRRs in connection with upgraded capacity is not necessarily a straightforward task such that CRRs can simply be awarded for the nominal amount of new capacity without consideration of all pertinent factors. The fact that the new capacity is "piggy-backing" off of the existing capacity raises important issues that need to be considered. For example, the parties might need to consider the extent to which a low-cost upgrade was possible only because significant cost was incurred to construct the underlying facility For example, if a project sponsor was able to expand the capacity of a line by simply installing an inexpensive capacitor, should it be entitled to CRRs for the full amount of additional transfer capability even though the transmission owner spent significantly more money constructing the underlying transmission line? The project sponsor probably should not receive 100 percent of the benefits of the low-cost expansion under these circumstances The ISO submits that such equity issues need to be considered when determining the amount of CRRs that should be awarded in connection with upgrades. In addition, it may be appropriate to consider the network implications of the new line or upgrade in determining the amount of CRRs that should be awarded

In developing the MD02 proposal, the ISO anticipated that the award of CRRs to parties financing either a transmission expansion or a transmission enhancement would be subject to a "Simultaneous Feasibility Test", designed to ensure that any CRRs awarded in conjunction with the expansion would be simultaneously feasible in combination with all previously awarded CRRs, thereby supporting the ISO's Revenue Adequacy (*i.e* , the congestion rents taken in by the ISO equal the congestion payments made to CRR-holders)

However, under some conditions and in some locations, grid enhancements decrease the transmission capability, thereby negatively affecting the holders of previously allocated

CRRs Under these conditions, the transmission expansion could render some previously awarded CRRs infeasible in the Simultaneous Feasibility Test. This is an intractable problem that requires special attention. One way to resolve this problem is to recommend that a particular grid upgrade should result in the award of favorable CRRs for the grid-enhancing portions and also the award of counter-flow CRRs (*e g.*, CRR obligations in the opposite direction) for grid-contracting portions. Under these conditions, the expander would be assigned sufficient CRR Obligations to restore the Simultaneous Feasibility of all previously awarded CRRs on the post-expansion grid. This approach would preserve Simultaneous Feasibility for all long-term CRRs awarded in conjunction with transmission expansion or generator interconnection along with any and all CRRs directly allocated to LSEs, CRRs sold through auctions, unconverted ETCs and the ISO's estimate of unscheduled loop flow.

It should be noted that some economic congestion would remain even after an appropriate grid expansion is implemented. Therefore, the awarded CRRs would continue to have value to the investors, albeit at less than the value of congestion before the expansion. Moreover, if grid usage expanded and congestion increased, the awarded CRRs would shield the investors from the associated risks and become increasingly more valuable over time The ISO submits that awarding CRRs to merchant transmission that will not earn a Commission-approved rate of return is sufficient incentive for investment without the need to provide additional "credits".

Finally, as noted above, the ISO is concerned that the provision of credits to market participants that expand the system could result in the inefficient expansion of the transmission system. For example, if generators are permitted to receive a full credit for transmission additions (*i.e.*, be paid back for their investment over a five year period), they may be indifferent to the location and the cost of interconnection. In such circumstances, a generator may choose to locate in an area of the grid that would require the ITP to install substantial upgrades to the system to interconnect the generator, even though the generator could locate at another less costly location. While an ITP will always be able to engage in discussions with such entities to discourage poor location decisions, any policies that encourage or facilitate inefficient or inappropriate expansion of the system must be discouraged.

2. CRR Features (PP 240/248)

The Commission proposes that CRRs be made available first in the form of receipt point to delivery point obligations rights and later in the form of option rights and flowgate rights. Later, when technically feasible and when market participants demand them, the ITP has to offer options or flowgates.

In its MD02 filing, the ISO proposes offering CRR obligation rights at first, and to treat non-converted existing transmission contracts as options. This is consistent with the direction in the NOPR. The ITP, through an extensive stakeholder process, should decide when it is appropriate to offer receipt point to delivery point options rights and flowgate rights. This decision should be based on technical feasibility, significant market participant interest and whether the time and resources necessary to implement are worth the benefit. An efficient integrated forward and real time energy market can be achieved without an expedited implementation of options and flowgate rights.

3. Multi-Year CRRs (P 249)

The Commission seeks comment on whether the Commission should require the ITP to offer multi-year CRRs when SMD is first implemented In addition, the Commission seeks comment on whether the ITP should be required to offer CRRs with terms tied to the planning horizon used in the region to satisfy the resource adequacy requirement

The Commission should not require ITPs to offer multi-year CRRs when SMD is first implemented. If the ISO is required to do so, without much experience in multi-year CRRs, market participants could have difficulty assessing their value. While historical congestion costs (if available) will provide some indication as to the value of long-term CRRs, such an assessment would also have to consider the impact of the Commission's new pricing policies as well as the impact of transmission planning and expansion efforts. Thus, it would be better for the Commission not to mandate the provision or term of multi-year CRRs initially. The Commission should afford each ITP the flexibility to develop the type and term of CRRs that best satisfies the need in the region. Although the ISO believes that the concept of offering CRRs with the same duration as the resource-adequacy planning horizon has some merit, the Commission should not require ITPs to offer this type of CRR. Rather, the Commission should allow each region to decide this issue independently after seeking stakeholder input.[13]

First, until each ITP determines the appropriate term of any multi-year CRR product, market participants can purchase CRRs in the annual and monthly increments necessary to substantially hedge the congestion costs exposure. Moreover, if a market participant wishes to obtain complete certainty with respect to the delivery of energy, it can fund the necessary transmission expansion and receive CRRs as compensation. Finally, CRRs do not ensure the "deliverability" of resources procured under a resource adequacy requirement. Although the ISO proposes to continue offering a scheduling "priority" as a feature of its CRRs, such priority does not guarantee deliverability. CRRs are only a financial hedge and offer no physical scheduling certainty. In conclusion, the ISO recommends that the Commission defer to each ITP to develop the type of CRR, including term, appropriate for its own region and compatible with established inter-regional trading practices

[13] The ISO originally explored the idea of providing FTRs/CRRs with a multi-year term when it first offered FTRs back in 1998 At that time, the ISO concluded that it would be too difficult to offer multi-year FTRs because of changing grid usage, configuration and the potential introduction/reduction in the then existing inter-zonal interfaces As the grid is enhanced or otherwise modified, it will be difficult to keep multi-year CRR products unchanged from year to year. One approach intended to address this issue -- an approach proposed in the ISO's MD02 proposal – is to offer only a limited number of multi-year CRRS This approach would reduce the likelihood that such rights will be altered on a year-to-year basis However, the ISO and stakeholders are still discussing the term and nature of CRRs in the context of finalizing the ISO's MD02 proposal. At this time it would be premature and inappropriate for the Commission to mandate the provision of multi-year CRRs

4. Funding for CRRs (P 250-251)

The Commission recognizes that when a significant amount of transmission facilities are out of service, so that less transmission service can be provided, the ITP may collect less congestion charge revenue from transmission users than the amounts owed to CRR holders. The Commission identifies two options for handling the revenue shortfall. First, the amount of congestion revenues paid to CRR holders may be reduced Second, the CRR holder would receive full protection against transmission costs, and the revenue shortfall would be assigned to the transmission owner. The Commission proposes the latter approach. The Commission also proposes that any revenue surpluses be paid to transmission owners, but seeks comment on the potential of this policy to discourage transmission expansions

In the ISO's MD02 proposal, the ISO provided for the creation of a single balancing account for all participating transmission owners ("PTOs"). Under the ISO's proposal, any surplus congestion revenues (*i.e.*, congestion revenues greater than CRRs) will be distributed to the balancing account. At the end of each month, funds from the balancing account will be allocated to CRR owners in proportion to their gross monthly shortfall, if any. Any remaining surplus is reserved for yearly allocation. At the end of the year, any reserved funds are allocated to CRR owners in proportion to their gross yearly shortfall. Any remaining surplus is paid to PTOs in proportion to their Commission-established revenue requirement. The ISO selected this approach for simplicity. The ISO believes that this approach offers CRR-holders with adequate protection against congestion costs. Any time there are deficient congestion revenues to compensate CRR holders, the ISO can utilize funds reserved in the CRR balancing account. However, if such funds are exhausted, CRR holders may not be fully compensated.

The ISO appreciates the Commission's concern that allocation of excess congestion revenues to transmission may discourage investment in the system. However, because CRR holders have first right to such revenues, the ISO does not believe this to be a significant concern Moreover, the ISO supports additional refinements to its own, as well as the

Commission's proposal, to create proper incentives for transmission owners to invest in and maintain their transmission systems. One such option would be to implement or increase transmission maintenance requirements/measurements on the transmission owners. Since start-up, the ISO has administered an effective transmission maintenance program with its transmission owners. An alternative approach would be to allocate excess congestion costs to transmission owners based on their transmission forced outage rates (accounting for *force majeure* events). Under such an approach, an ITP would measure and track each transmission owner's maintenance records and could reward good maintenance practices by allocating a greater share of excess congestion costs to well performing transmission owners. Whereas the Commission proposes that transmission owners make up any deficiency in congestion costs that result from a forced outage, the ISO would utilize the balancing account to compensate CRR holders through the course of a year and then, at the end of a year, undertake an accounting of congestion revenue adequacy/deficiency and allocate any excess revenues or costs to the transmission owners based on their annual transmission maintenance performance. Either approach is likely to be contentious and, if the Commission adopts such policies, the Commission must ensure that, to the greatest extent possible, all rules, requirements and consequences for transmission owners are clearly specified on an *ex ante* basis.

5. Secondary Market for CRRs (P 252)

The Commission believes that it is important that there be an active secondary market for CRRs. In addition, the Commission proposes to require that the ITP conduct periodic auctions of CRRs.

The ISO supports an active secondary market that will allow CRRs to be traded freely. The ISO does not believe it is necessary for CRR holders to have to resell them as a part of the auction, however. The ISO intends to conduct periodic CRR auctions, just as it today auctions FTRs periodically, but the ISO does not contemplate facilitating a secondary market in CRR trading or establishing a requirement to sell CRRs in such a market or auction. The ISO believes that it is preferable for third parties to operate such markets, and they can do so easily. However, to the extent the ISO ultimately retains the existing scheduling priority feature of CRRs, as proposed in its MD02 proposal, the ISO, by necessity, would retain its existing "Secondary Registration System" so that it could track and honor that scheduling priority.

6. Pre-Day Ahead Auctions (P 254)

The Commission proposes that the ITP would be permitted, but not required, to offer pre-Day Ahead auctions for energy and ancillary services. In conducting pre-Day Ahead auctions, the ITP would allocate transmission capacity among competing demands for CRRs, forward energy and forward ancillary services so as to maximize the economic value of the winning bids. The ISO does not believe pre-Day Ahead auctions are a critical element for operation of efficient Day-Ahead and Real-Time integrated energy and ancillary services markets. In principle, the ISO believes that the primary benefit of such markets is that they may provide additional opportunities and incentives for forward contracting and the procurement of adequate capacity resources by LSEs. As such, these markets may also provide additional incentives for infrastructure development To that end, any pre-Day Ahead auctions would by necessity have to be coordinated with the procurement rules and activities of load-serving entities and the local regulatory authorities that oversee those efforts. To date, at least in the West, most of these activities occur in the bilateral markets, and the ISO anticipates that this practice will continue. Thus, the ISO believes that such activities (and, if necessary auctions or markets) are best facilitated/coordinated by third parties-- primarily the LSEs that play in the long-forward markets.

VI. Day Ahead and Real Time Market Services (PP 257-327)

The ISO supports the use of bid-based security constrained economic dispatch to allocate transmission and generation capacity across various energy and Ancillary Services products, so long as adequate market power mitigation measures are in place. The ISO continues to believe that until sufficient resource adequacy measures are in place in California and the existing supply-demand imbalance is remedied, resource owners throughout the West must continue to be obligated to offer their available capacity to the spot and real-time markets.

A. Day Ahead Markets (PP 257-297)

1. Multi-Hour Block Bids (P259)

Under the NOPR, transmission customers would be able to respond to price signals by submitting multi-hour block bids, requesting transmission service for a block of consecutive hours and indicating the maximum price for the entire multi-hour period. The Commission seeks comments on the proposal's merit and any implementation difficulties.

The ISO believes that this market design feature should not be required under SMD, at least initially. Allowing multi-hour block bids is technically possible, but it would greatly complicate the day-ahead congestion management process. Also, allowing block bids would divert time and resources away from focusing on more critical core SMD elements Furthermore, it is not clear why this feature is necessary given that the transmission customers could procure CRRs over the same number of hours for the desired price and hedge themselves against congestion costs. Finally, allowing arbitrary multi-hour bid blocks might provide a mechanism for physical withholding (by submitting real supply bid blocks against paired virtual demand bid blocks, in a combination that is clearly infeasible.)

2. Multiple Day Schedules (P 263)

The Commission seeks comments on whether a customer should be allowed to provide a schedule for multiple days or have a standing scheduling request that would remain in effect until changed by the customer Any schedule request, once scheduled by the ITP would become financially binding on the customer at the close of each day's day-ahead market.

The ISO supports allowing market participants the opportunity to submit standing bids, or a schedule for multiple days, with the understanding that unless withdrawn, such bids would be subject to appropriate market power mitigation binding for all hours that pre-specified system and/or market conditions arise. These bids, once scheduled by the ISO will be financially binding, and standing bids would roll over each successive day unless withdrawn

3. Transmission Service Across Borders (P 265)

The Commission proposes to treat transmission service across borders in the same way as internal transactions Thus, an importing or exporting customer could either schedule transmission service and agree to pay the transmission usage charge regardless of the level or submit a bid that limits its congestion exposure The Commission proposes to make both options available to transmission customers. However, the Commission states that it would prefer "one-stop shopping" with ITP coordination, and the Commission seeks comment on whether this can be done.

The ISO supports the Commission's proposal to treat transmission service across borders the same as internal transactions. The ISO's experience indicates that at any time parties are treated differently, or different rules apply, opportunities for inappropriate manipulation arise and the real-time operating decisions and actions of system operators are further complicated With respect to the Commission's articulated goal of facilitating one-stop shopping, the ISO supports that goal and is engaged in discussions, through the SSG-WI forum, to facilitate such a market feature The ISO submits that the SSG-WI is the appropriate body to address "one-stop shopping" in the West. Absent the creation of a single scheduling and congestion management system (*i.e.*, one RTO), the ISO believes that the standardization of market and scheduling timelines across regions will greatly facilitate interregional trading.[14] These discussions are currently taking pace in SSG-WI's Congestion Management Alignment Work Group. As part of the SSG-WI discussions, the Common Systems Interface Coordination

[14] One note of caution is that timeframes for forward market scheduling must enable and accommodate forward outage scheduling timeframes or some mechanism to resolve the need for scheduled work on facilities (*i.e*, reliability based, including preventative maintenance where reliability is not yet demonstrably threatened) and must be established as having priority over market driven actions.

work group is examining the options for creating a single OASIS site for the Western RTOs. Based on market participant feedback, this would greatly enhance trading across the RTOs' boundaries. In addition, as noted above, SSG-WI's Price Reciprocity work group is currently exploring options for reducing transaction-based barriers to trading among and between the proposed RTOs in the West. If successful, this too should facilitate inter-regional trading.

Finally, the ISO notes that the SSG-WI Congestion Management Alignment work group has assumed the difficult task of determining whether it is necessary for the RTOs to adopt a common network representation of the Western transmission system in order to develop consistent congestion prices at the seams. Such an approach would send appropriate price signals to all market participants, especially those that schedule across the seams, for purposes of allocating and using the transmission system. In the end, modifying or, if appropriate, transitioning from the existing interchange scheduling procedures (physical, contract-path based approach) will require the collective efforts of all parties in the West, including the WECC The ISO supports such discussions, and believes that SSG-WI, at this time, is the appropriate forum for discussing such issues.

4. Prescheduling Option (P266)

The Commission notes that, under the New York ISO's pre-scheduling option, a customer may schedule such a transaction across borders up to eighteen months in advance of the dispatch day. Once submitted, the transaction would be financially binding unless the New York ISO permits the customer to withdraw the prescheduled transaction. The Commission seeks comment on whether a similar pre-scheduling option should be included in SMD.

As noted above, the ISO supports pre-scheduling options, both for internal RTO transactions and transaction across the seams of an RTO. However, the ISO believes that such matters are best addressed on a regional basis and believes that SSG-WI is facilitating an appropriate discussion forum for this topic.

Process aside, the ISO believes that this kind of long-term advance scheduling option may be another useful complement to long-term bi-lateral contracts and would appear to promote long-term generation supplies. The ISO favors this and other market features that encourage long-term certainty within a LMP environment As long as the customer agrees in advance to pay the market-clearing price for transmission (*i.e.*, be a congestion price taker), the ISO would be willing to arrange special pre-scheduling features. Providing service across borders, however, requires inter-ITP coordination. SSG-WI is the appropriate body to address these issues

5. Calculation of Transmission Losses (P 267)

The Commission seeks comment on whether transmission losses should be recovered on the basis of the marginal cost of losses or if they should be recovered on the average cost of losses

The ISO is currently evaluating, in the context of finalizing its MD02 proposal, how best to price and settle transmission losses. The ISO is considering both an approach similar to that in place in the NY ISO wherein losses are both priced and settled on a marginal basis. , as well as a methodology similar to that employed by PJM, where all load pays a fixed, system-average based, loss adder on top of the applicable LMP The ISO also is considering a "scaled" marginal loss approach similar to that already in place at the ISO As part of its evaluation, the ISO will assess each pricing/settlement approach with respect to (1) impact on least cost dispatch, (2) consistency with LMP principles; (3) bidding behavior (incentives); (4) self-provision of losses; and (5) simplicity.

6. Payment of Transmission Losses (P 268)

The Commission seeks comment on whether transmission customers should have the choice of paying for losses in cash or in kind or, alternatively, whether all transmission customers should be required to pay for losses in cash.

Under MD02, the ISO is considering incorporating losses into locational marginal prices instead of assessing them (1) solely to generators and imports, as is done currently, or (2) applying a flat percentage loss adder to all locational marginal prices, as PJM currently does. Incorporating transmission losses into the locational marginal prices appears to distribute fairly the costs of losses and sends the right price signal. In addition, this approach would ensure that an entity with a generator serving a load at the same bus would not incur a loss charge.

Paying for losses in kind would significantly complicate scheduling for the ITP except for market participants that submit bilateral self- schedules, in which case the injections could exceed the withdrawals by an estimate of the amount of losses. In the latter case, market participants should be responsible for charges that result from the under-provision of losses. Recognizing that certain market participants may prefer to self-provide losses, the ISO recommends that any market design accommodate this functionality

7. Scheduling for Energy-Limited and Intermittent Resources (PP 274-275)

The Commission proposes a scheduling option to address the special conditions facing energy-limited resources such as hydroelectric and environmentally constrained thermal resources. The ITP would schedule energy from these resources when prices were highest, maximizing profits for the energy-limited resources. The Commission seeks comment on whether other scheduling options or regional variations should be included for energy-limited resources in the tariff The Commission also proposes to include the ISO's scheduling option for intermittent resources as part of Standard Market Design. However, the Commission seeks comment on whether there is a better way to schedule intermittent resources.

As discussed *supra* in Section V.A.3, the ISO supports scheduling flexibility to address the legitimate issues and complexities of accommodating hydropower and other energy/use-limited resources. While the ISO supports use of pre-day-ahead scheduling and coordination options, the ISO does not advocate direct ITP management of energy or use-limited resources in order to maximize the value of such resources. The ISO submits that such function is best performed by the resource or portfolio owner/manager.

With respect to use-limited resources' satisfaction of the "must-offer" obligation, in order to guard again physical withholding, the ISO advocates that use-limited resources submit an annual resource energy usage plan, with monthly resolution for each such resource. The plan would be supported by demand forecast and expected primary resource limitations (hydro/fuel/emissions quota). For each month, the plan would provide the intended level of energy production from the resource. The resource plan would be subject to monthly revision if important changes occur compared to the initial demand and resource forecasts. The monthly resource plan would be further broken down into weekly and daily resource utilization plans by the respective Scheduling Coordinator. The "must offer" obligation would be deemed satisfied if the resource owner abided by the accepted energy resource plan, and scheduled or bid additional ancillary services as set forth in the plan.

With respect to a Scheduling Coordinator's ability to protect use-limited resources, the ISO advocates that a portion of the capacity of a use-limited resource that is 10-minute responsive qualifies for operating reserves and can be protected by submitting a Contingency Flag. Indeed, the Commission approved such an approach in Amendment No. 38 to the ISO Tariff and the ISO has experienced good results with more units being offered to and providing needed reserves. However, because there is a limit to the total amount of self-provided and ITP-purchased Operating Reserves, this protection only applies to about 7% of the energy being provided to the load, which may or may not be deemed adequate by the entity desiring to protect its use-limited resources Of course, market participants can further control and protect their use of use-limited resources through their annual, monthly, weekly, and daily resource plans. The use-limited resource would also be allowed to bid energy beyond its accepted resource plan (at the relevant price cap, or above the cap subject to justification) in any period to reflect its perceived opportunity cost of the resource. However, such bids would have to be included in the resource plan to avoid mitigation by any Automatic Mitigation Procedures ("AMP").

With respect to the issue of the pooling of use-limited resources, the ISO proposes that ITPs not use the unscheduled energy or the protected energy bids from the use-limited resources of one Scheduling Coordinator to make up for another based on economic considerations. However, under pre-specified system conditions (*e.g.*, declaration of monthly peak hours in the forthcoming Operating Day) or contingency conditions (*e.g.*, occurrence of a contingency in a pre-specified contingency list), the ITP would pool the use-limited resources of all Scheduling Coordinators to maintain reliable system operation.

The final issue that has been raised is the appropriate relief for a Scheduling Coordinator as a result of an ITP's utilization of use-limited resources. The ISO submits that a market participant whose use-limited resource is utilized by the ITP beyond the level envisioned in the daily resource plan would not be subject to penalties that may otherwise be associated with capacity deficiency in the remaining part of the capability period.

8. Demand Participation (P 276)

The Commission states that demand participation in the market is critical for an effective wholesale market and advocates permitting demand to bid directly in the market with load bids. The Commission states that other measures where an ITP pays load more than the market clearing price to reduce demand are costly and, as such, are not proposed by the Commission.

Given the insufficiency of demand response in the markets of all existing independent system operators and the importance of developing demand response to help create competitive energy markets, the Commission should allow regional variation across ITPs to explore facilitating demand response. Many independent system operators have developed different programs (*e.g.*, emergency response programs as well as market programs such as the ISO's Participating Load Program); however, these programs have neither been consistently implemented nor settled At a minimum, after implementation of SMD and allowing some time to analyze the cost-effectiveness of different programs, the Commission should outline the specific services that demand can participate in and the method to allow for them to schedule, bid, and settle in these markets. In addition, a standard method of calculating the load's actual curtailment is also needed (*i.e.*, all parties need to agree on how to determine a load's "base-line" level) During the initial implementation of SMD, the proposed measure of allowing demand to submit load bids is necessary but allowing region-specific demand response programs will help.

The ISO believes that the primary vehicle for facilitating the development of price-responsive demand programs will be the resource adequacy mechanisms ultimately adopted by each region or, if necessary, by the ITP. As recognized by the Commission, it has often been necessary to pay load above-market prices in order to attract participation in demand response programs. This is likely to be true in the future in price- or bid-cap limited markets. The ISO believes that resource adequacy-related mechanisms offer a means to provide load (as well as any new resource) that participates in such programs with adequate compensation. Similar to new generation, load-based resources often have start-up capital expenditures for which they need complete and timely cost recovery Long-term forward contracts (*i.e.*, bilateral contracts) negotiated in the context of satisfying a resource adequacy requirement offer such accost-recovery vehicle. Thus, in the ISO's opinion, facilitating demand response goes hand-in-hand with developing and implementing a framework for resource-adequacy in each region.

Finally, while the ISO does not believe that an ITP necessarily has to develop demand response programs, the ITP must facilitate demand participation in the broader markets. Thus, the Commission must ensure that whatever standard wholesale market design is ultimately adopted, that design must include the "functionality" necessary facilitate load participation. For example, if the Commission were to standardize the three-part bid structure inherent in the existing Eastern independent system operators (and proposed by the ISO in its MD02 proposal), the Commission must ensure that such cost/bid-based structure permits demand to bid in a manner to recover costs incurred as a consequence of participating in a ITP's markets

9. Provision of Reactive Power (P 283)

The Commission seeks comment on whether generators who provide real or reactive power should receive additional compensation for the additional transfer capability that they create, to provide incentives to produce energy that increases transfer capability. In particular, the Commission asks whether the generator should be paid the higher of its opportunity costs or the market congestion value of the additional transfer capability created. The Commission also asks how locational market power concerns should be addressed in these circumstances.

Currently, the ISO procures reactive power services from generators that operate pursuant to Reliability Must-Run ("RMR") contracts. The RMR contract compensates a unit for the opportunity cost of providing reactive power if providing reactive power at the ISO's request pre-empts that unit's ability to meet a market energy obligation. The ISO believes that this approach is reasonable and necessary. Because the need for, and the ability of a generator to provide, reactive power is location dependent, any supplier on whom an ITP must depend to provide reactive support has locational market power and should be subject to appropriate local market power mitigation.

The ISO does not believe that a market or incentive-based pricing scheme is appropriate. If the Commission decides to establish one, the ISO believes that such resource would frequently be – and must be -- subject to necessary market power mitigation measures, *i.e.*, measures that would likely eliminate or reduce the value of any such market or incentive pricing proposal. However, the ISO does support a cost-based approach whereby a supplier receives compensation for legitimate costs incurred in providing reactive support, including opportunity costs.

10. Scheduling, System Control and Dispatch Services (P284)

The Commission seeks comment on treating Scheduling, System Control and Dispatch Services as a basic cost of providing transmission service rather than as an ancillary service.

The ISO supports this approach. Currently, Scheduling, System Control and Dispatch are not among the ancillary services in the ISO markets. The ISO recovers the costs associated with providing Scheduling, System Control and Dispatch services in a separate Grid Management Charge designed to recover the start-up and ongoing expenditures of operating the ISO Control Area, facilitating all of the ISO's markets, and all of the support functions necessary to fulfill those responsibilities.

As opposed to an "ancillary" service that any third-party could elect to have a transmission provider provide, the core function of the ISO, as well as an ITP, must be the provision of these basic services. Thus, if the Commission were to move to a "re-structured" paradigm where ITPs provide these functions for the benefit of all market participants that choose to use the transmission system and participate in the ITP's markets, then the notion that these services are "ancillary" to the provision of transmission service is erroneous

11. Charging Exports for Ancillary Services (P 296)

The Commission notes that under Order No 888, exports are not charged for certain ancillary services and seeks comments on whether exports should be charged for ancillary services under SMD.

Firm exports should be charged for ancillary services, just as internal load is charged. If the export is firm, the reliability council (for California it is WECC) requires that the originating control area provide regulation and operating reserves for the export. Thus, since ancillary services are being provided in this case, firm exports should be charged for ancillary services If the export is non-firm, then the originating control area is not required to provide ancillary services and therefore, should not charge the entity for such services.

B. Scheduling After the Close of the Day Ahead Market (PP 298-304)

1. The Need for a Reliability Commitment Procedure

The ISO supports the accommodation of post-day-ahead schedule changes. In particular, the ISO supports a means for an ITP to commit the resources necessary to satisfy ITP-forecasted day-ahead load. As the ISO has indicated in its MD02 proceeding, the need for a post-day-ahead "reliability" commitment is essential To the extent that participants in the ITP's markets fail to self-schedule a sufficient amount of resources to satisfy the ITPs's aggregate (*i.e.*, system-wide) load forecast, the ITP must be able to ensure that there are sufficient resources on-line to serve the anticipated load. Absent this ability, the ITP will either be forced to procure the necessary power in real time or it will be forced to curtail load – neither of which are attractive options from a reliability or cost perspective. The Commission has approved reliability unit commitment mechanisms for every other independent system operator --- except the ISO -- in order to ensure reliable operation of the transmission grid.[15]

Based on the discussions with stakeholders in the context of developing the ISO's final MD02 design, the ISO recommends that the Commission adopt a reliability commitment procedure that enables an ITP to commit unloaded capacity up to a level deemed appropriate by the ITP to satisfy ITP-forecasted load. Once committed by an ITP (with assurance that the generator will be compensated for its start-up and minimum-load energy costs), such capacity would have to be available for dispatch, as needed, by the ITP in Real-Time.[16] Of course, there

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[15] *See New England Power Pool,* 88 FERC ¶ 61,147 at 61, 491 (1999) (ISO New England commits sufficient reserves to ensure that it has adequate supply committed to meet forecasted load), *Central Hudson Gas & Electric Corporation, et al.*, 86 FERC ¶ 61,062 at 61,222 (1999) (NYISO commits sufficient capacity to meet the load forecast and provide ancillary services); *see also* PJM West Reliability Assurance Agreement, Article 8

[16] The issue as to what resources are obligated to be available for commitment by the ITP is a larger issue that must be resolved in the context of resource adequacy and/or utilization of a "Must Offer" type obligation and the type and level of compensation provided to resources under those arrangements.

are a number of issues that must be addressed in connection with any reliability commitment procedure.

One issue is which market participants should bear the costs associated with the ITP's commitment of units. As proposed by the ISO in its MD02 filing, the ISO would allocate the costs of the units committed pursuant to this process primarily to those market participants that failed to schedule adequate resources to satisfy their actual load (*i.e.*, those that under-scheduled their actual load)

A second issue is the amount of capacity/energy an ITP should purchase. While an ITP must prudently commit such resources at a level commensurate with satisfying its reliability requirements, the ISO does not propose establishing limits on the ITP's commitment practices. Such limits may impose inappropriate restraints on ITP actions necessary to ensure reliable system operation. To the extent that the ITP over-commits, both the ITP and the LSE that caused the ITP to commit additional capacity can take corrective action going forward. Specifically, the ITP can correct for any errors in its load forecasting approach, if that was the cause of the over-procurement. Similarly, LSEs can correct for any load-forecasting error that caused them to under-schedule load.

A third issue is whether minimum load and start-up costs should be cost-based bid-based. Existing independent system operators utilize both cost-based and bid-based approaches, and both approaches have positive and negative aspects. The ISO believes that a cost-based approach for minimum load and start-up costs appropriately compensates resources for being available, while providing an opportunity for the resource to collect market-based revenues through its energy bids.[17] The energy bid can reflect the opportunity cost for energy-

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[17] The Commission has approved cost-based pricing for start-up and minimum load costs in connection with the "Must Offer" obligation in California. *California Independent System Operator Corporation*, 97 FERC ¶ 61,293 (2001). There is no legitimate reason why the pricing of start-up and minimum load costs should be any different under a unit commitment procedure.

limited resources. In addition, a cost-based approach is appropriate because, if the ISO had not committed the unit, the unit would not have earned any revenues.

The ISO also recognizes that certain of the Eastern independent system operators have employed a bid-based mechanism. If the Commission were to adopt such an approach, the ISO believes that, similar to the rules in place in the markets, market participants should only be permitted to change such bids on an infrequent periodic basis – perhaps every six months. Allowing resource owners to submit market-based start-up and minimum load bids on a daily basis would likely exacerbate market power problems during high load periods when the ISO may need to commit all available resources in the Control Area.

Finally, the ISO believes that the proper objective function of the reliability commitment procedure should be to optimize the maintenance of reliability and the minimization of commitment costs. The purpose of a reliability commitment is to minimize the cost of committing – not dispatching – available generation A commitment based on the minimization of a combination of start-up, minimum load and expected energy cost would be justifiable if the ITP is heavily dependent on imports to ensure supply sufficiency (such as in California).

2. The Need For Post-Day Ahead Scheduling Flexibility

The NOPR proposes a two-settlement system wherein market participants submit day-ahead schedules that are financially binding, and any schedule changes made subsequent to the day-ahead are settled at the real-time price.

As the Commission is aware, since start-up, the ISO has operated under a three-settlement system. Under this approach, market participants have the ability to submit both day-ahead and hour-ahead schedules to the ISO, both of which are financially binding (presently, for Inter-Zonal Congestion, going forward under MD02, for all transmission) The ISO, with the support of the majority of its market participants, believes there are significant benefits to conducting an Hour-Ahead market as well as a Day-Ahead market. The Hour-Ahead market provides market participants with the opportunity to utilize more recent information to adjust schedules and arrange new deals after the close of the Day-Ahead market, but much closer to real time, and before being subjected to variable and potentially volatile imbalance energy prices. While a two-settlement system (*i.e.*, no hour-ahead settlement) may be easier to implement and administer, a three-settlement system similar to that already in place in the ISO's markets is more compatible with existing practices in the West, where market participants have always relied on the ability to make schedule adjustments up to real time and, from a comfort level, do not want to be financially exposed to unknown (*i.e* , ex post) real time prices The ISO submits that the Commission should permit each ITP to determine what is appropriate for its region, based in large part on the desire of its market participants, and should not mandate that a two-settlement system be adopted.

C. Real Time Markets (PP 305-325)

1. Price Determination and Settlement (P 310)

The Commission states in the NOPR that the ITP would determine energy prices in the real-time energy market for each node for each 5-minute period or other sub-hourly period where a 5-minute determination is not technically achievable.

The ISO is planning on moving to 5-minute security constrained economic dispatch and will provide LMPs by node at 5-minute intervals, in part, to provide more regular dispatch signals to resources. This 5-minute dispatch interval must not, however, preclude ITPs from dispatching more frequently if emergency conditions require. Thus, the Commission must grant ITPs the flexibility to dispatch units on a more frequent basis In addition, it is important to distinguish real-time pricing and real-time settlement. Despite finer (*i.e.*, 5-minute) pricing, independent system operators may settle on a 10-minute basis or only on an hourly basis. Many loads do not have revenue quality meters to enable settlement on a 5-minute basis, and LSEs have not indicated that they support 5-minute settlement.

2. Ex Post versus Ex Ante Prices (P 315)

With respect to the determination of real-time prices, the Commission identities two options. One option is to set the prices using near real-time estimates, *i.e.*, *ex* ante pricing commensurate with ITP dispatch instructions and assuming full compliance of the resources dispatched. The other option is to base the price of the actual marginal resource clearing the market in real time, *i.e., ex post* pricing based on performance (response to dispatch instructions) The Commission proposes to adopt the *ex post* rule because it creates incentives for bidders to act consistent with their bids. The Commission seeks comment on the choice between *ex post* and *ex ante* pricing.

The ISO suggests that the Commission allow regional flexibility and permit each region to decide, after extensive stakeholder input, whether to use *ex ante* or *ex post* pricing. Currently, as part of its MD02 filing, the ISO is proposing *ex post* pricing. This would reduce the incentives for firms to deviate from their schedules and ensure that ITPs do not procure unnecessary reserve capacity, thereby freeing more generating capacity to compete in the real-time energy market.

The ISO cautions that if no penalties or charges for uninstructed deviations are provided for under ex-post pricing scheme, there may be new opportunities for physical withholding. For example, suppose a generator with 5 MW/min ramp rate and forward schedule of 80 MW is instructed to move up at its maximum ramp rate. Assuming a 5-minute dispatch interval, this target operating point would be 105 MW. Under an *ex-ante* pricing scheme (similar to that currently in effect under the ISO tariff), the pricing is based on 105 MW operating point. If the generator does not move (a form of physical withholding), it is assessed an uninstructed deviation penalty. Under the *ex-post* pricing regime, however, if the generator does not move, the price would be set based on its 80 MW operating point (assuming it is the marginal generator). But, in the subsequent interval, the ISO cannot dispatch it above 105 MW (ramp rate limit) and must dispatch a higher cost unit. Because of the portfolio effect, the supplier would not mind foregoing 25 MW of generation in return for a higher MCP resulting from a higher cost unit. Therefore, adopting *ex-post* pricing with no measures against deliberately not following dispatch instructions might provide incentives for this type of physical withholding.

The ISO recommends *ex-post* pricing along with measures against physical withholding associated with systematic failure to follow ITP's dispatch instructions.

3. Uninstructed Deviations (P 316)

The Commission seeks comment on whether market participants should face additional charges for "uninstructed" deviations in real time from their schedules, *i.e.*, for producing or taking a different amount of energy in real time than was scheduled without permission or direction from the ITP. The Commission also seeks comment on whether the increased costs of regulation service or ancillary services should be allocated to the entities (buyers and sellers) that had uninstructed deviations from their schedules since the costs were incurred to serve these entities Moreover, the Commission seeks comment on whether and how to establish market prices for ramping capability. Finally, the Commission seeks comment on whether the SMD Tariff should include penalty provisions for uninstructed deviations that threaten system reliability and how such penalty provisions should be structured.

The Commission approved the uninstructed deviation penalties proposed by the ISO in its May 1, 2002 MD02 Filing. *California Independent System Operator Corporation*, 100 FERC ¶ 61,060 (2002). The Commission likewise should approve uninstructed deviation penalties under SMD. In the MD02 proceeding, the ISO demonstrated that uninstructed deviations were rampant in the ISO Control Area and that uninstructed deviation penalties were necessary to deter uninstructed deviations. Specifically, the ISO demonstrated – and no party offered one iota of evidence to the contrary --that uninstructed deviations have: (1) made it extremely difficult for the ISO to operate its Control Area reliably in a manner consistent with NERC and WECC standards and good utility practices, (2) adversely affected the ISO's ability to manage inter- and intra-zonal congestion, (3) resulted in an inefficient dispatch of resources, and (4) inappropriately affected prices in the ISO's markets. *See* May1, 2002 MD02 Transmittal Letter at 34-38 and Affidavit of Thomas Siegel, Attachment Q to the MD02 Filing, filed in Docket No. ER02-1656. The ISO hereby incorporates these documents by reference as supporting the need for uninstructed deviation penalties.

4. Lumpy Generators (P 319)

The Commission seeks comment on whether lumpy generators should be eligible to set the energy price in the day-ahead market. The ISO submits that if a lumpy generator is dispatched based on the outcome of an economic minimum-cost function, and is therefore necessary to serve load for any portion of the lumpy quantity, that generator should be allowed to set the MCP Consider the following example. a lumpy generator has 1 bid segment of 100 MW at $10/MWh. A flexible generator has 3 bid segments of 50 MW each, at $7/MWh, $8/MWh and $20/MWh, respectively. The ISO needs 140 MW. The minimum bid cost solution would be to dispatch 100 MW from the flexible generator and 40 MW from the lumpy one. However, in order to get the 40 MW from the lumpy generator we actually have to dispatch the lumpy generator for 100 MW and reduce the flexible generator by 60 MW. As a result the actual marginal cost (cost of meeting the next incremental MW) is $7/MWh (from the flexible generator). However, the lumpy generator was dispatched and was therefore deemed necessary to meet load economically Therefore, the selected bid from the lumpy generator of $10/MWh would set the price. In this case, the lumpy generator should be allowed to set the price (at $10/MWh). If this example is extended out one more interval and find that the system only needs 70 MW of imbalance energy, but the lumpy resource has remained at 100 MW due to a minimum run-time constraint, then the economic solution does not require energy from the lumpy resource. At this point, the lumpy resource should not be allowed to set the price

As explained *infra*, the ISO's MD02 design allows the lumpy generators to set the price only in Real-Time The emphasis in MD02 is to avoid dwarfing load response in Real-Time (*i.e.*, let the load see the high prices set by the lumpy generators in every pricing interval rather than pay such generators an uplift "smeared" over 24 hours of the day). In the MD02 design, the lumpy generators do not set the price in the forward market because there is no concern about inability of load response in the forward market (*i.e.*, Load can bid p-q curve in DA and HA).

The ISO agrees with the Commission's suggestion that generators that can only be dispatched at discrete levels should be able to set the Real-Time price, but only under specific conditions when they are needed. Because a lumpy generator dispatched at a break point does not fit the usual definition of a marginal resource, the impact of the *ex post* prices set by the lumpy generators at their location on *ex-post* process elsewhere in the network will have to be determined based on Real Time congestion patterns. This may require a "pricing run". There are two possible approaches to a pricing run· (1) preserve the congestion pattern and locational prices that would result if the lumpiness of the resources dispatched at a break point were ignored; or (2) adopt the congestion pattern resulting from the lumpy generator dispatched at a break point. The pricing run will ensure that the price at the lumpy generator's location is not below its break point price, and the price differences among different locations are preserved commensurate with the adopted congestion pattern

With respect to the Day-Ahead Market, lumpy generators should be allowed to set the energy price to avoid having different pricing rules for certain generators in the Day-Ahead market and the Real-Time market. However, the ISO does not believe this is essential because demand can respond to prices in the forward markets, but has very limited ability to respond to prices in Real Time. The ISO believes the limited number of lumpy generating facilities will keep the Day-Ahead market sufficiently competitive even when price increments are greater than 1 MW.

D. Market Rules for Shortages or Emergencies (PP 326-27)

The SMD Tariff would require ITPs to file proposals with the Commission regarding the implications for market pricing of reliability procedures. The proposals would need to be consistent with the adopted resource adequacy mechanisms, but could vary to reflect regional differences in reliability requirements. The Commission seeks comments on what, if any, more specific requirements should be included in the Final Rule.

As explained further below, the ISO believes that, in order to further support the creation of proper incentives for load-serving entities to forward contract and procure the necessary resources to satisfy their load (plus reserves), it may be appropriate for ITPs to establish appropriate "adders" to the cost of energy procured through the ITP's real-time market. Such adders would penalize those load-serving entities that choose to rely on the ITP's spot markets to satisfy their load obligations In addition, the ISO believes that it may be appropriate to establish a graduated system of penalties depending on the shortage conditions that exist. For example, the price for real-time energy under a Stage 2 Electrical Emergency would be higher than the price of real-time energy under a Stage I Emergency. In the end, such measures would have to be linked and be consistent with longer-term resource adequacy proposals developed by either the local regulatory authorities or ITP. As the ISO recently requested to the Commission, the ISO believes that it is appropriate to determine the form and function of any resource adequacy requirements established by local regulatory authorities before developing or implementing any ITP-directed measures, including the application of real-time energy adders or penalties.

VII. Other Changes to Improve the Efficiency of the Markets (PP 328-369)

A. Regional and Independent Calculation of Available Transfer Capability, Performance of Facilities Studies and OASIS (PP 333-334)

1. Performance of Facilities Studies (P 333)

Under SMD, the Commission would require that calculations of transmission capability and the performance of facilities studies for transmission expansion be performed by an independent entity.

The ISO believes that there should be some market incentives to encourage non-jurisdictional entities to participate in regional planning. This would include entities in Mexico and Canada. Although the ISO calculates ATC, the Transmission Owner, not the ISO, performs studies related to requests for new transmission service or interconnection. The ISO submits that it is sufficient for the ITP to "cause" the studies to be performed by internal or external entities, subject to ITP approval.

2. Common OASIS (P 334)

The Commission states that transmission capabilities must be calculated not for a single utility's service territory, but regionally to encompass existing trading patterns and power flows, particularly parallel path flows on neighboring systems The Commission proposes to require a common OASIS for the Region

As noted above, SSG-WI's Common Systems Interface Coordination work group is in the process of developing a proposal for a joint or common Western OASIS site While many details remain to be worked out, the ISO supports such efforts and believes that such an effort will greatly facilitate inter-regional trading.

B. Regional Planning Process (PP 335-350)

1. General Principles

The comments provided below regarding regional planning are largely the same as those that the ISO has previously submitted to the Commission in this proceeding.[18] Based on the importance of the regional planning process to the success of the Commission's overall effort in developing consistent market rules and promoting infrastructure development, and for the benefit of those not familiar with the ISO's earlier comments, the ISO herein repeats many of the salient points from its prior filing.

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[18] See "Comments of the California Independent System Operator Corporation on the Commission's RTO Workshop - Lessons Learned After Three Years of Operation –" pp. 12-20, filed on November 12, 2001

The ISO supports the development of transmission planning and expansion principles that:

- facilitate development of a robust transmission system capable of supporting competitive regional markets (*i.e.*, a robust "interstate" transmission system); and
- where appropriate, consider viable non-wires alternatives to proposed and needed local transmission projects.

As recognized by the Commission in Order No. 2000, effective congestion management protocols are necessary but not sufficient in ensuring that the transmission system is expanded in a manner that facilitates the development of competitive regional energy markets. Transmission planning and expansion and congestion management protocols must work together to achieve that goal.

The ISO believes that it has much value to add to the discussion on the transmission planning and expansion issue. The ISO's coordinated transmission planning and expansion process has been an effective process that has led to the approval of almost $1 5 billion in new transmission infrastructure Moreover, the ISO has initiated certain pilot projects to evaluate non-transmission alternatives to proposed transmission projects.

While the planning process at the ISO has been a significant success, better coordination with the California Public Utilities Commission (CPUC) and other affected state agencies is necessary to ensure consistent and timely permitting of transmission facilities approved by the ISO and to strike an appropriate balance with respect to the delineation of responsibilities in the planning and siting processes. The ISO is committed to resolving this critical issue.

In addition, and perhaps most importantly, the ISO is in the process of developing a detailed methodology to assess the economic benefits of transmission projects that cannot be justified solely on reliability grounds. In 2001, the ISO filed testimony in the CPUC proceeding for siting of an expansion of Path15, the major transmission interface between Southern and Northern California.[19] For the first time since it was established, the ISO assessed the need for the expansion based on economic grounds. The ISO is undertaking a collaborative process with the Transmission Owners and relevant California state agencies to develop a methodology for the evaluation of the economic benefits of transmission projects that builds on the work undertaken in the assessment of Path 15. More recently, the SSG-WI planning working group has undertaken a review of the ISO's economic expansion criteria to determine how such a methodology could be applied on larger inter-regional basis to support transmission expansion across the entire West.

<u>The ISO Coordinated Grid Planning Process</u>

The regional planning process outlined by the Commission in the NOPR is largely consistent with that already in place through the ISO's coordinated grid planning process. The ISO's coordinated planning process is predicated on the development of PTO-specific annual transmission plans that are developed as part of an open and public process. During that process, market participants are also invited to step forward and sponsor transmission projects that they wish to include in the applicable PTO's annual plan. The ISO's primary role is to oversee and coordinate the development of the PTOs' annual transmission plans and to develop, based on those plans, an integrated transmission plan for the entire ISO Controlled Grid. The ISO's process has been remarkably successful (stakeholders have almost unanimously praised the planning process), and the ISO believes that such a process can be the foundation of any RTO's transmission planning process. The ISO Tariff provides that the

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[19] The ISO's testimony and supporting exhibits (studies) can be found at: <u>http //www.caiso com/docs/2001/06/12/200106121509511 7712 html</u> The ISO's testimony was filed in the following proceeding before the CPUC. AB 970 OII Investigation No. 00-11-001 <u>Los Banos-Gates 500 kV Transmission Project: Application 01-04-012.</u>

ISO, Participating TOs, or a market participant can establish the "need" for a transmission project on the grounds of "reliability" or "economics". The need for a transmission project must be clearly established in the ISO's process if the project is to be approved and supported by the ISO for inclusion in the ISO's Access Charge. The PTOs in California have an obligation to plan their respective transmission systems so as to reliably serve the load in their service areas. Thus, the primary focus of their annual transmission plans is on identifying and planning those transmission projects necessary to maintain reliable service.

Since inception, the ISO anticipated that "economic" transmission projects would be supported by either LSEs that desired to obtain access to new or alternative suppliers or suppliers that desired access to certain markets. As contemplated by the Commission in the NOPR, a critical function of an ITP - and hence a regional planning process – is to facilitate the development of transmission projects necessary to support the proper functioning of regional markets. Although the ISO acknowledges the role of effective price signals and the market to further transmission investment, the ISO believes that there is a legitimate "backstop" role for ITPs in furthering transmission expansion, especially when expansion may not be in the best interests of individual market participants.

Consistent with that notion, the ISO believes that the Commission should, to the extent possible, empower ITPs with the necessary authority and oversight authority to ensure that transmission projects identified by the ITP as needed are developed and built in a timely manner by their member PTOs. To further that effort, the Commission should support development of the tools and methodology necessary to support economic expansion of the grid. While the Commission can provide incentives for grid expansion such as CRRs, the ISO believes that, in the end, ITPs will have to step forward to ensure that the grid is expanded in a manner to promote the development of competitive regional markets.

Competitive Solicitations – The ISO's Tri-Valley Experience

The Commission's proposed regional planning process focuses on developing a least-cost transmission plan that includes "non-wires" alternatives to transmission, such as generation and load-based projects. The ISO has direct and pertinent experience on this matter

Beginning in the Fall of 1998, the ISO seriously began to examine whether it should formally incorporate a competitive solicitation for non-wires alternatives to proposed transmission projects in its grid planning process. Motivated in part by the ISO's interest in seeking cost-effective solutions to grid constraints, the ISO began to develop a formal process for conducting competitive solicitations for non-wires alternatives This process culminated in the filing of Amendment No. 24 to the ISO Tariff. However, due to stakeholder concerns with certain aspects of the filing, the ISO withdrew Amendment No. 24 from consideration at the Commission

The following year, based on the concepts developed in the context of Amendment No. 24, the ISO embarked on a pilot-project initiative designed to test the viability of undertaking competitive solicitations for non-wires alternatives to proposed transmission projects. Working with Pacific Gas and Electric Company ("PG&E"), the ISO sought alternatives to PG&E's proposed Tri-Valley transmission project PG&E's Tri-Valley project was a proposed 230 kV transmission line that, as proposed, would run through certain residential areas. PG&E and the ISO concluded that a project was needed to reliably serve load in the area As further detailed in the attachments to the ISO's "RTO Week" comments, filed on November 12, 2001, the ISO issued a Request for Bids to provide such transmission alternatives. While the ISO received a number of bids, the bids were ultimately deemed to be not competitive with the proposed transmission project, and the ISO authorized PG&E to proceed with its proposed transmission project.

Based on this experience, the ISO hereby offers the following observations from its experience in developing and undertaking competitive solicitations.

Deferral vs Displacement

Perhaps the most critical issue raised in the context of the ISO's competitive solicitation experiences is whether non-wires alternatives can, or should be deemed to, fully displace (*i e* , permanently defer) or just defer for a specified time the need for transmission. This becomes a critical issue when evaluating the bids received from potential non-wires projects and when considering appropriate compensation for such projects For example, in the Tri-Valley RFP, the ISO made an up-front determination that non-wires projects would only defer the need for the identified transmission project for five years. The ISO determined that after five years, load growth and other factors would require transmission expansion in the Tri-Valley area. Thus, as a result of that determination, the implicit "value" of any non-wires project would be the time-value of money of deferring the transmission project. Under this approach, assuming a twenty-percent carrying charge, the value of deferring a $100 million transmission project for five years would be $100 million. Based on that pre-determined value, respondents to the Tri-Valley RFP were constrained as to the value of their bids.

The "deferral" methodology clearly biases the results of such solicitations in favor of transmission expansion. However, setting aside the cost-comparison issue, there are many qualitative differences between transmission, generation and load-based projects. For example, transmission projects provide system operators with enhanced operational flexibility and, by increasing transfer capability, can facilitate more effective competition by providing load with greater access to more suppliers. Generation and load-based projects, if available when needed, can be used to maintain reliability and can avoid or defer, in part, the impacts on communities and the environment from transmission projects. However, strategically sited generation projects, in particular, can give rise to local market power concerns.

The Need For and Details of Performance Contracts

The ISO has concluded that, in order to ensure that a non-wires project will be and remain available to satisfy the reliability requirements for which it was selected, it must be subject to a legal obligation to respond to ISO dispatch notices at a specified mitigated price through some form of performance contract or other mechanism. In other words, in order to ensure that these projects are available for dispatch, these projects must be legally obligated to perform as directed by the ISO. In the Tri-Valley case, the ISO developed a pro forma non-wires performance contract Certain of the difficulties the ISO experienced in developing the pro forma agreement were how to structure the contract with the appropriate performance penalties for non-performance, the term of the contract, and cost-recovery of contract costs. The ISO believes that it struck an appropriate balance between incentives and penalties in the performance contract. As originally proposed, the term of the contract was five years – the length of the deferral period. However, tying the length of the contract to the deferral period raised the question as to whether contract renewal rights were needed and the terms of that renewal. The ISO had concerns about the ability of a project owner to exercise market power when negotiating an extension, especially in circumstances where the ISO was dependent upon that project to provide critical reliability services.

Whether a new form of contract is needed, or existing mechanisms can be used, it is likely that an ITP must have the ability to call on a unit when needed at mitigated prices if that unit is used to displace a needed transmission expansion project. However, even when relying upon the use of pro forma agreements, the burden associated with administrating such contracts can be great and could further detract from an ITP's primary mission, *i.e* , providing open and non-discriminatory transmission service and ensuring reliable grid operation.

Finally, in the context of the Tri-Valley evaluation, the ISO also had to address the difficult issue of contract cost recovery. The ISO concluded that, because the ISO was seeking viable alternatives to proposed transmission projects, the costs of any non-wires projects should be recovered from the PTO in whose service area the project is located. The ISO therefore structured the billing and payment terms of the contract similar to those already in place for RMR Contracts, whose costs are also paid by the PTOs. While the Commission's NOPR has not foreclosed any specific pricing mechanism, the ISO believes that the Commission should be flexible to innovative approaches to both procuring and pricing necessary grid services.

<u>Conclusions</u>

In summary, the ISO believes that the Commission must establish transmission planning principles that support (1) development of a robust transmission system capable of supporting competitive regional markets (*i.e* , a robust "interstate" transmission system); and (2) where appropriate, consideration of viable non-wires alternatives to proposed and needed local transmission projects However, while the ISO supports the concept of facilitating competition between transmission, generation and load-based projects, the ISO cautions the Commission that it must resolve the policy issues raised herein before mandating that ITPs conduct such competitive solicitations.

Furthermore, while the ISO recognizes that certain transmission projects could be deferred, or possibly displaced, by non-wires alternatives, the ISO urges the Commission to consider a more targeted policy. The ISO advocates that, instead of requiring a broad-based solicitation for all identified needs, that the Commission instead focus its efforts on lower or sub-transmission voltage level project. The ISO believes that such projects are well-situated for examination of non-wires alternatives. Based on the ISO's experience and observations, non-wires projects have a better chance of competing against (displacing) lower-voltage projects, since the load-driven requirements of such projects are less. However, the ISO advocates that the Commission closely examine the need for, and prudence of, requiring ITPs to seek competitive alternatives to high-voltage transmission projects that are necessary to facilitate regional markets.

In the end, the ISO does not believe that proactive transmission planning, with an emphasis on promoting development of a grid capable of supporting competitive markets, and the targeted consideration of viable non-wires alternatives, are mutually exclusive. Moreover, the ISO believes both principles will further the objective of cost-effective solutions to address identified needs, both with respect to competitive market outcomes (generation/energy) and with regard to those activities still regulated (transmission).

2. Economic Transmission Expansion-- The ISO's Development of Criteria to Evaluate Economic Transmission Projects

To date, the ISO has approved close to $1.5 billion of transmission projects, and virtually all of those projects were needed for reliability purposes. Until recently, no PTO or Market Participant had stepped forward to sponsor what the ISO deems an "economic" transmission project. That is, no project sponsor had stepped forward to justify the need for a project solely on the grounds that it was needed either to eliminate congestion and ensure delivery of energy to load or to increase access to alternative supply (*i.e.*, mitigate the market power of local suppliers). As noted above, the ISO believes that there is a legitimate and necessary backstop role for ITPs in ensuring that the infrastructure necessary to support competitive regional markets is in place. Moreover, ITP determinations of need on economic grounds can provide the basis for incorporating the costs of transmission projects justified to support competitive regional markets into Access Charges.

On July 3, 2001, the ISO issued an RFP soliciting proposals for the development of "Transmission Project Evaluation and Justification Principles and Methodology Recommendations" necessary to support an economic transmission project This effort was intended to further develop and refine the methodology to assess the economic benefits of a transmission project pioneered in the ISO's analysis of the expansion of Path 15. As further explained in the RFP, the recommendations to be developed from the RFP:

are expected to provide the basis for the ISO to assess the economic benefits and justify the construction of transmission projects to expand California's access to dispersed and diverse electricity markets and resources, in order to lower the cost of electric service for California consumers.

The ISO firmly believes that the development of a methodology to assess the economic benefits of transmission upgrades will lay the foundation for future transmission expansion not only in the West but across the nation As noted above, the bulk of the transmission projects approved to date in California (and most likely nationwide) have been justified or needed in order to maintain the reliability of the transmission system. In the future, the ISO believes that an increasing percentage of the transmission projects will be needed to further support development of robust and liquid regional energy markets. Absent the development of clear and appropriate criteria for the evaluation of such projects, economic transmission upgrades may never be initiated and, more likely, will linger in a regulatory limbo as various constituencies labor over the details of and the need for the transmission projects.

The ISO believes that the development of a sound economic methodology for evaluating, supporting and allocating the costs of economically-based transmission expansion will further the ISO's and Commission's objective of facilitating competitive electricity markets. Subsequent to the development and validation of such a methodology, market participants, financiers and regulators will have a solid foundation for developing and supporting economic transmission projects. Moreover, development of a methodology can only further enhance the ability of ITPs to play an important backstop role in the creation of a network system capable of facilitating a seamless national energy market.

3. Multi-State Entities (P 339)

The Commission states that a Multi-State Entity could be an important component of the regional planning process. In the Commission's opinion, multi-state entities, along with an open regional planning process, would preserve the states' role in siting decisions promoting regional solutions.

The ISO supports the creation of an effective regional planning process. To that end, the ISO fully supports and is heavily engaged in the SSG-WI Transmission Planning work group. As further detailed in the January 8 SSG-WI Filing, the purpose of that group is to develop a regional planning process that is capable of supporting economic expansion of the entire Western transmission system. Currently, the SSG-WI has broad participation by all segments of the market participant community, as well as active participation by the affected states. In fact, the SSG-WI effort is building off of the previous work sponsored and completed by the Western Governor's Association. Recognizing the ultimate authority of each state with respect to the siting of new transmission within its boundaries, the SSG-WI effort is aimed at creating a process that builds consensus across the West for major new transmission facilities, facilities necessary to facilitate inter-regional transfers and facilitate competitive market and efficient outcome for all consumers throughout the West.

4. Environmental Impact (P 346)

The Commission proposes that the regional planning process consider the least environmental impact option. However, environmental issues may not be considered as part of the planning process.

The ISO agrees that a robust regional planning process should consider all viable options (*e.g.*, options that satisfy the reliability as well as economic requirements or "need")), including environmentally-friendly options put forth by either state agencies, or any market participant. However, the ISO agrees that "environmental issues" (*e.g.*, routing and other environmental-impact issues) are best left to the States

As to the determination of "need" for a given facility, the ISO supports the concept of deferring to ITP/RTO determinations. The ISO believes that the ITP/RTO is best positioned to determine, based on established reliability or economic criteria, the need for a given transmission facility. While the ISO appreciates the obligations of states to consider the need for a facility, the ISO believes that appropriate deference to ITP/RTO determinations should be given by the states.

5. CRR Feasibility (P 347)

The Commission states that all entities can propose projects as long as the project did not make existing CRRs infeasible due to loop flow problems The Commission inquires whether this means that existing CRRs, especially long term CRRs, have to be considered in the planning process for new projects to ensure that existing CRRs will not be negatively impacted.

According to standard utility practice, a new transmission project is accepted only if it does not have any significant negative impact on the transfer capability of the network from established sources to established sinks Similarly, when CRRs are allocated/auctioned, an ITP will conduct a "simultaneous feasibility" test to determine that, in combination, all CRRs can be accommodated The reality is that changes to grid usage and topology will impact the feasibility of CRRs. As noted earlier, the primary reason the ISO has not offered long-term FTRs to date is because of the difficulty of preserving the nature and value of those FTRs in an ever-changing environment. Thus, the real issue to be addressed in the context of transmission planning and expansion efforts is not whether to assess the impact of any new transmission project on any existing long-term CRRs – the answer to that is yes – but how to balance and reconcile the need for long-term rights with the reality f an ever-changing grid. The ISO recommends that the Commission defer to each ITP to fashion a set of rights that reflects those considerations

6. Thresholds (P 348)

As explained above, the ISO recommends that the Commission establish a voltage-level threshold above which an ITP will not have to undertake a competitive solicitation for non-wires alternatives to proposed transmission projects The ISO recommends that the Commission permit each ITP to establish an appropriate threshold based on an examination of the facilities under its control

C. Modular Software Design (PP 351-360)

The Commission proposes to require that the software meet the following characteristics: (1) transparency; (2) testability; and (3) modularity. In addition, the Commission would require that the input and output data systems and other Electronic Data Interchange be standardized in a common data model including a data dictionary (glossary and/or data definitions) and common network description. The Commission asks whether it should use the evolving NAESB process or forums set up by the Electric Power Research Institute to establish such standards or employ another approach.

The ISO supports the Commission's goal of increasing the transparency, flexibility and, to the extent practical, modularity of the software used to run and support ITP-related markets and services Software interface standardization, in the long run, is likely to ease implementation efforts and ultimately reduce costs, while facilitating market participant testing and the implementation of their own supporting systems. The ISO has adopted similar principles to guide its MD02 implementation effort -- principles that the ISO believes are consistent with those outlined by the Commission. In fact, the ISO recently compared its system architecture and design objectives with those outlined in the NOPR and determined that they were completely aligned (See "Presentation for December 9 Technical Conference" submitted to the Commission on December 2,2002, in Docket No ER02-1656-000)

The ISO recommends that ITPs, as the ultimate "business unit owners" of the applicable systems and software, are the appropriate entities for developing initial requirements and standards in these areas. The ITPs, under the auspices of the ISO Chief Information Officer Council, will propose a standard development process that will result in ISO-approved technical standards being communicated to NAESB, EPRI, and other interested parties Furthermore, the ISO suggests that NAESB and EPRI efforts be brought into closer alignment to ensure consistency between the engineering system and other related and supporting software systems such as market systems Moreover, the ISO strongly recommends that the system data dictionary efforts be fully integrated and coordinated with the existing Common Information Model ("CIM"), a product of EPRI

In support of that recommendation, the ISO once again supports the efforts of the SSG-WI in furthering the development of common or compatible systems and software. Although it is at an early stage, the Common Systems Interface Coordination ("CSIC") working group under SSG-WI is discussing the development of a common or compatible business model for the West, as well as the need for and details of joint infrastructure development. The ISO is currently engaged in and supports these efforts The ISO also is currently engaged in a national effort to advance the development of common ITP data exchange standards. This work is being performed under the auspices of the ISO CIO Council in response to a joint request of the CEOs of the existing independent system operators.

While the ISO concurs with the NOPR regarding the desirability of the standardization approach, it should be noted that the standardization effort itself would introduce delays while the standards are developed and software that incorporates the standards is developed.

D. Transmission Facilities That Must Be Under the Control of an Independent Transmission Provider (PP 361-369)

In the NOPR, the Commission raises the issue of what facilities appropriately belong under the control of the ITP. The Commission states that the seven factor test it developed in Order No 888 to determine what facilities are transmission facilities subject to Commission jurisdiction and what facilities are distribution facilities subject to state jurisdiction is the appropriate starting point for determining which facilities belong under the control of the ITP. The Commission requests comment whether, either in addition to or in lieu of the seven-factor test, the Commission should use a bright line voltage test (*e.g.*, 69 kV) to determine which facilities are placed under the control of the ITP. The ISO supports continuation of the seven-factor functional test to determine the facilities that must necessarily be under the operational control of an ITP in order to ensure reliable system operation and non-discriminatory access to the transmission system. The seven-factor test has worked well to identify the necessary transmission facilities that need to be placed under the control of the ITP. This test gives the transmission owner and ITP a framework to gauge the primary function of the transmission facility and, in practice, appears to accurately gauge which facilities function primarily as transmission and those that service a distribution function.

The ISO does not believe the same outcome can be achieved through application of a *generic* bright line threshold. Use of a standard threshold would create multiple scenarios in which the objectives of the SMD would not be met, such as (1) placing some facilities under the ITP that are not necessary for ensuring reliable system operation and/or non-discriminatory access to the grid, (2) ITP not having control over facilities that have a negative impact on reliability or the provision of non-discriminatory transmission service, (3) generators that are contained within non-Commission/ITP jurisdictional "pockets" and cannot be ensured of open, non-discriminatory access to the transmission grid. At an absolute minimum, the ISO believes that the Commission should not establish a generic or standard bright-line threshold, but instead should defer to ITPs, in collaboration with regional entities, to develop such a threshold. Furthermore, as is the case in California, the fundamental operating nature of the grids in an ITP's area may not be the same. As the Commission is aware, prior to restructuring each utility/transmission provider planned its system on an *integrated* basis. Thus, certain utilities established different trade-offs between the use of generation and transmission to ensure reliable system operation. In California, for example, the underlying nature of Southern California Edison Company's system is different than that of Pacific Gas & Electric Company's system. Similarly, the structure of the non-FERC-jurisdictional entities' systems in California is different that that of the IOUs Therefore, while the ISO could attempt to establish a bright-line threshold for differentiating between transmission and distribution level facilities in California, the underlying nature of the systems within California would make that, at best, difficult and most likely the result would be arbitrary. If the threshold is set too low (*i.e.*, 69kV or 12kV) then distribution facilities may fall under the ITP's operational control without any enhancement of network reliability. If the bright line is set too high (i.e., 345 KV or 200 kV) then lines that impact grid reliability may not be under the ITP's operational control. Either result is problematic.

Therefore, the ISO recommends that the Commission continue to apply the seven-factor test to determine which facilities must be under the control of an ITP. In the alternative, should the Commission adopt use of a bright-line test based on voltage level, the Commission should permit regional variation and allow each ITP to determine the appropriate voltage-level delineation between transmission and distribution facilities based on the nature of the integrated grid in its region.[20]

Finally, while the focus of this discussion is on determining the appropriate delineation between transmission and distribution facilities, the ISO is concerned that the NOPR fails to appreciate the distinction between operation of the grid and control area operation While the ISO recognizes that the Commission has yet to mandate that an ITP be a control-area operator, based on ISO experience, the Commission needs to recognize this important distinction in function.

Control Area responsibilities are greater than those necessary to operate the grid Therefore, the operation of non-ITP controlled facilities can have an enormous impact on the ability of an ITP to fulfill its control-area operator responsibilities, as established by NERC and the appropriate regional council. The requirements of operating a grid are a subset of the requirements necessary to be a control area operator. The Commission would be remiss if it does not distinguish between these functions.

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[20] The ISO recognizes that a bright-line voltage threshold may be appropriate for ratemaking purposes in order to distinguish between high-voltage (*i.e.*, regional) and low-voltage (*i.e.*, local) *transmission* facilities The ISO supports and has already proposed such a distinction. Further, as discussed above, the NOPR also contemplates establishing such a distinction for ratemaking purposes

Currently, the PTOs in California continue to operate (and thus control) key facilities in California, including generation tie-lines. Operation of these facilities, which is guided by PTO-established operating protocols and procedures that are most frequently negotiated with the affected generation facility, can directly impact reliable transmission system operation. All of these PTO-established procedures must be – but are currently not – known to the ISO. Therefore, while, as a general matter, it is necessary to determine which facilities are under the operational control of an ITP, for those ITP's that are also control-area operators, the operating procedures and protocols of *all* facilities located within the ITP's Control Area must be known to the ITP and the facility-owner/operator must be responsive to the ITP's/Control Area operator's operating directives.[21]

VIII. Transition to Single Transmission Tariff (PP 370-389)

A. Customers Under Existing Transmission Contracts (P 375)

The Commission states that it is concerned that pre-Order No 888 contracts could permit the parties to extend a contract indefinitely through the use of roll-over or evergreen provisions in the contracts. The Commission seeks comment on whether it should limit the ability of parties to extend these contracts past their initial term or, if that has passed, at the end of the next roll-over period. The Commission also asks what limitations are appropriate.

As stated above, the ISO does not oppose the Commission's proposals regarding the treatment of existing transmission contracts. Specifically, the ISO supports, in the long-run, conforming all existing transmission contracts and service to the same terms and conditions of service as that under an ITP's tariff. Uniform market and transmission scheduling rules are critical to ensuring a market that is efficient and not subject to manipulation. The ISO offers

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[21] The ISO does not necessarily believe that, for purposes of day-to-day operations, these facilities must be under the operational control of the ITP. At a minimum, however, the ISO recommends that the ITP be made aware of and familiarize itself with the procedures that guide operation of these facilities

below several operational and market design reasons supporting a Commission decision prohibiting transmission owners from renewing ETCs as such contracts expire under their own termination provisions.

First, from an operational perspective, certain existing contracts that the ISO must honor allow certain entities an ability to schedule 20 minutes within the operating hour. The schedules for the ISO's Hour-Ahead market must be submitted two hours before the operating hour This timeline discrepancy requires the ISO to assume that the full contract right will be used by the ETC Rights holder and, as such, the ISO must reserve the full capacity in both the Day-Ahead and Hour-Ahead markets. Ultimately, not all existing contract rights may be exercised, thereby resulting in unused capacity on the grid. This "phantom congestion" leads to inefficient dispatch and raises costs because market participants pay for congestion that does not in fact exist.

Second, from a market design perspective, the reservation of unscheduled ETC capacity beyond the Day-Ahead market undermines the consistency between forward and real-time markets – a fundamental tenet of the ISO's MD02 market design as well as the basis for the LMP-based pricing the Commission advocates Also, it is possible that allowing ETC extensions and roll-overs could contribute to anticompetitive behavior because, as the Commission is acutely aware, different rules between markets create opportunities for gaming and manipulation As a matter of fairness to all market participants and for the benefit of well-functioning forward markets, it is critical that all market participants are put on the same timelines for scheduling their transmission service (as soon as possible after existing contracts expire, if not immediately.)

Finally, from a legal perspective the termination of evergreen provisions would be consistent with the Commission's actions in the natural gas industry with respect to individually certificated, Part 157 transportation contracts (which are the natural gas industry's equivalent of pre-Order No 888 contracts). Specifically, the Commission ruled that conversion to open access, Part 284 transportation service was appropriate for shippers whose contracts for Part

157 service expire/terminate *See Transcontinental Gas Pipe Line Corporation*, 60 FERC ¶ 61,119 (1992).

Thus, the ISO recommends that the Commission prohibit transmission owners from renewing ETCs as such contract expire pursuant to their own termination provisions.

B. Allocation of CRRs (PP 376-382)

1. Accommodation of Load Growth (P 376)

The Commission seeks comment as to whether, and under what circumstances, load growth should be accommodated by the direct allocation of CRRs The initial CRRs would be receipt point-to-delivery point obligations.

From the ISO's perspective, as it pertains to its proposed MD02 design, the initial allocation of CRRs is critical. In order to ensure an orderly and fair transition to the new market (and transmission service) paradigm, existing customers must be convinced that they will receive rights comparable to those they have today. Subsequent to any initial allocation, the ISO supports the provision of CRRs to match load growth only if such load-growth provisions are already included in, or contemplated under, the existing transmission contract or arrangement. CRRs should not be provided to those with contracts that provide for the delivery of a fixed or contract-demand amount of power.

As a general matter, and absent any previously existing obligation for the ISO to accommodate load, a LSE can procure any incremental amount of CRRs necessary to serve load through monthly CRR auctions or through trading on the secondary market. As reflected in its MD02 filing, the ISO believes that it may be possible to allocate monthly CRRs to new load without impacting the long-term (3-year) and mid-term (1-year) CRRs to the load that was there at the time of the initial allocation. However, once the term of the existing mid-term or long-term CRRs has expired, allocation to all load can be based on the load history during the relevant Historical Reference Period.

2. Type of Term (P 378)

The Commission seeks comment on the type of term that should be used for purposes of the allocation of CRRs for existing contracts.

As proposed by the ISO in the context of finalizing its MD02 proposal, the ISO believes that it is appropriate to base CRR allocations to existing contract holders on those entities' actual *average* transmission usage over the past *year*. The ISO does not support allocating CRRs to those entities based upon their *maximum* usage or *contract-demand* entitlements. Allocating CRRs to existing contract holders on that basis would significantly reduce the amount of capacity available to new users – capacity/rights that would likely go used by the existing contract holder during many hours of the year.

An allocation based on average usage during the most recent year should provide existing contract holders with sufficient hedge against congestion charges Moreover, to the extent that an existing contract holder believes that its prior year's usage does not reflect its historical and, thus, likely future usage of the system, such entity can demonstrate to the ITP that its allocation must be adjusted. Because this should be a one-time allocation (subject to resolution of the load growth issue outlines elsewhere), it is appropriate for the ITP and existing contract holder to work together to amicably resolve issues pertaining to their allocation of CRRs.

3. Length of CRRs (P 380)

The ISO's comments regarding multi-year CRRs and the length of CRRs are set forth in Section V.C 3, *supra*

4. Liability Limitations (P 389)

The NOPR raises a number of issues regarding liability limitations. Specifically, the Commission seeks comments on the following issues: (1) whether there is a need to include liability provisions in the Commission's *pro forma* tariff; (2) under what circumstances should liability protection be provided in a Commission open access transmission tariff (*e.g.*, should the

Commission provide such protection only where it is not available through state tariffs); (3) if the Commission adopts liability provisions, should they be generic or do they need to be adopted on a regional basis; (4) whether the standards adopted in a Commission *pro forma* tariff should reflect what was previously provided under state law; and (5) how the Commission can resolve the issue in the multi-state context of an independent system operator or RTO.

In the NOPR, the Commission has invited comment regarding the need to include limitation of liability provisions in the *pro forma* tariff and the circumstances in which liability protections should be included in the tariff. Consistent with the discussion *infra*, the ISO urges the Commission to include limitation of liability provisions in the tariff and to make them applicable to all services provided by the ITP under the tariff.

In the open access era, the Commission's general policy has been to refuse to permit electric utilities to include limited liability provisions in their Commission-approved tariffs for transmission-related activities *See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting* Utilities, 81 FERC ¶ 61,257Order No. 888-B, at 62,080 (1999). In particular, the Commission has routinely rejected proposed tariff language that would limit an electric utility's liability related to events caused by simple negligence. *See, e.g., New York Independent System Operator Corporation, et al*, 90 FERC ¶ 61,012 at 61,034-35 (2000). For example, under Section 14.1 of the ISO's Tariff, the ISO is liable for damages that result from the performance or non-performance of its obligations under the ISO Tariff that are the result of negligence, as well as intentional wrongdoing, on the part of the ISO. The Commission has, however, permitted higher standards of liability for certain independent system operator's performance of market-related activities. *See Central Hudson Electric Corporation, et al.*, 88 FERC ¶ 61,138 at 61,384 (1999); *PJM Interconnection, L.L.C.*, 86 FERC ¶ 61,247 (1999).

The ISO submits that the Commission should reconsider its policy and approve necessary and appropriate limitations on the liability of entities providing transmission and wholesale market (including market monitoring) services pursuant to tariffs that are subject to the Commission's jurisdiction. The Commission's current policy appears to be predicated on two mistaken beliefs. First, the Commission has opined that transmission providers should rely on state tariffs/laws for liability protections. See *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilties and Transmitting Utilities,* Order No. 888-A, FERC Stats & Regs. [Regulations Preambles 1996-2000], ¶ 31,036 at 30,301(1997). Second, the Commission seems to think that the inclusion of discrete liability limitation provisions in Commission-approved tariffs would exculpate the transmission provider from all liability. *See* Order No. 888-B at 62,080. The former rationale ignores the fact that the rates, terms and conditions of transmission service provided by regional transmission organizations, independent system operators and stand-alone transmission companies are subject to the sole jurisdiction of the Commission under the Federal Power Act. Independent transmission providers like the ISO are not subject to state public utility commission jurisdiction, do not file tariffs with state public utility commissions, and the state(s) have no regulatory authority to review rates, terms and conditions of transmission service. Thus, the ISO and similarly situated independent transmission providers are not protected by state-approved tariffs and laws; such transmission providers must look exclusively to the Commission for liability protections in service tariffs

The Commission's second rationale also is not a valid reason to reject liability limitation provisions because inclusion of such provisions in transmission tariffs will not exculpate the independent transmission provider from all liability. For example, tariff provisions likely would not limit liability for direct damages for gross negligence or willful misconduct in connection with services provided under the tariff. Under these circumstances, independent service providers would still have a meaningful incentive to operate the transmission grid and provide service in accordance with Good Utility Practice.

It is imperative that the Commission reasonably limits the liability of ITPs for negligent acts. Because ITPs lack state tariff protections, ITPs could be exposed to damage awards of catastrophic proportions for simple negligence For example, if there was an accidental outage that affected Silicon Valley, there could be significant financial losses. Liability for failure to supply could bankrupt a company like the ISO, which is a non-profit entity. Absent meaningful Commission-approved limitation of liability provisions and faced with potentially open-ended liability, ITPs are finding and, in the future, will find it difficult and prohibitively expensive to obtain adequate liability insurance. The ISO notes that it has budgeted for a 40 percent increase in its insurance premiums for 2003. Moreover, it is the ISO's understanding that the insurance premiums of other transmission providers have increased significantly more than that amount. The escalating costs of insurance have an adverse impact on ratepayers because such costs are passed through to ratepayers as a cost of service item. On the other hand, end use customers would not have to change their investment and insurance policies because the Commission simply would be "continuing" existing state policy. In that regard, most states have adopted a policy of limiting the liability of transmission providers for simple negligence related to the provision of transmission service.

ITPs also must be able to attract capital in order to operate in a cost-effective manner. However, ITPs' potential exposure to indeterminable liability makes it more difficult to obtain favorable financing.

Thus, there are sound reasons for limiting the liability of ITPs. Liability limits will result in lower rates. There will not be any cross subsidization of large customers by small customers as a result of small customers essentially insuring large customers.[22] ITPs will be protected from open-ended and potentially drastic liability. Moreover, limiting the liability of ITPs would require those parties in the best position to estimate risk exposure and to undertake protective measures to manage the risks themselves.

A limitation of liability is especially appropriate for a non-profit transmission provider such as the ISO. The Grid Management Charges ("GMC") charged by the ISO merely recover the ISO's costs and expenses, with no return on equity or profit component. The ISO has relatively few assets, and no party contributes capital to the ISO. Because the ISO's operations are structured in this manner, the only funds available to pay any damages would be the GMC charges recovered through the ISO Tariff and insurance, the cost of which is recovered through the GMC charges Limiting the ISO's liability will reduce the ISO's insurance expense and protect customers from bearing the cost of damage claims This will shift the cost responsibility from all customers to those customers that are better able to obtain insurance tailored to their specific circumstances or protect themselves with alternative measures.

The unique circumstances facing regional ITPs also support the inclusion of limited liability provisions in ITP tariffs In that regard, ITPs manage and operate an amalgamation of facilities that are owned, and heretofore operated independently of each other, by third parties. Incremental facilities and entire transmission systems are being, and will be, added to the operational control of ITPs. It is wholly unreasonable to expect that ITPs will operate the transmission grid flawlessly at all times under these circumstances. It is therefore punitive to

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22 Transmission providers are not permitted to charge a premium rate to a customer from whom the transmission provider faces a greater magnitude of potential liability because of a greater reliability on electricity. For example, the cost of a service interruption to Silicon Valley manufacturers would be significantly greater than the cost of a service interruption on residential consumers; yet, the transmission provider is required to provide transmission service to each type of customer at the same rate.

subject ITPs to liability for simple negligence. Further, given the turmoil and financial uncertainty in the marketplace, it is unreasonable to hold ITPs such as the ISO liable for simple negligence in connection with services such as market operations and market monitoring. For example, in California the electricity crisis led to two companies –the California Power Exchange and Pacific Gas & Electric Company – filing for bankruptcy and another investor-owned utility – Southern California Edison Company – losing its creditworthy status. Moreover, one supplier, *i e* , Enron, has gone bankrupt and other major suppliers are in dire financial straights. Moreover, as the Commission is well aware via the so-called Enron memos, there is evidence of extensive "gaming" by market participants in California's electricity market. Many of the specified "games" jeopardize reliable and efficient operation of the ISO-controlled grid and the markets operated by the ISO. Thus, the ISO must attempt to "keep the lights on" and operate markets efficiently, while at the same time dealing with significant credit risk issues and constantly guarding against gaming activities that could threaten reliable operations of the transmission grid and the efficient functioning of ISO markets. This makes it wholly inappropriate to impose a simple negligence standard as opposed to a gross negligence standard.

The failure to approve liability limitations also can unduly chill ITP market monitoring and compliance activities. For example, the ISO has a Department of Market Analysis that monitors the market for evidence of gaming, market manipulation and the exercise of market power Similarly, the ISO's Compliance department monitors compliance with the ISO's Tariff as well as specified performance and technical requirements. The ISO also oversees and coordinates transmission and generator maintenance outages and facility deratings. The Commission expects the ISO to be vigilant in monitoring these activities, however, the potential exists that the actions and recommendations of market monitoring and compliance units will be tempered due to the threat of potentially extensive liability. A gross negligence standard is appropriate for these types of activities so that market monitors and compliance units can perform their functions with the utmost effectiveness.

The ISO notes that the Commission has approved a broad waiver of liability for actions undertaken by PJM's market monitoring unit In that regard, Section IX of PJM's market monitoring plan provides that the market monitoring unit "shall not be liable" to any market participant, PJM member or PJM customer "in respect of any matter described in or contemplated by" the market monitoring plan, including "liability for any financial loss, loss of economic advantage, opportunity cost, or actual or consequential damages of any kind resulting from or attributable to any act or omission" of PJM or its market monitoring unit under the market monitoring plan *PJM Interconnection, L.L.C.,* 86 FERC ¶ 61,247 (1999). Likewise, the Commission approved the New York Independent System Operator's ("NYISO") market monitoring liability provisions which limits the NYISO's liability to a willful misconduct standard rather than a simple negligence standard, concluding that the NYISO would "not be able to properly monitor and implement measures to correct market power if the threat of lawsuits becomes a variable in its decision making." *New York Independent System Operator, Inc.,* 89 FERC ¶ 6,196 at 61,064 (1999). Despite approving broader liability limitations for PJM's and NYISO's market monitoring units, the Commission approved a mere negligence standard for the ISO. The disparate treatment accorded the ISO is arbitrary and capricious and not the product of reasoned decision making At a minimum, the Commission must approve broader liability standards for the market monitoring and compliance activities of **all** ITPs.

Finally, the ISO notes that the Commission has approved a gross negligence standard for the NYISO's Services Tariff, ISO New England's Tariff for Dispatch and Power Administration Services and the PJM Operating Agreement. *See Central Hudson Electric Corporation, et al.,* 88 FERC ¶ 61,138 at 61,384(1999). The Commission found that a gross negligence standard was appropriate because the services involved were not open access transmission services. *Id.* The Commission has also justified such limited liability provisions on the grounds that the transmission provider does not have significant assets. *See Pennsylvania-New Jersey-Maryland Interconnection,* 81 FERC ¶ 61,257 at 62,274 (1997). Despite approving a gross negligence standard for the eastern independent system operators' market services, the Commission has approved a negligence standard for the ISO's market services. This is inappropriate and unjustifiable. Even if the Commission determines that it is not appropriate to approve a gross negligence standard for open access transmission services, consistent with the treatment accorded PJM, the NYISO and ISO New England, the Commission must, at a minimum, approve a gross negligence standard for **all** ITPs' market services

IX. Market Power Mitigation and Monitoring in Markets Operated by the Independent Transmission Provider (PP 390-456)

A. Resource Adequacy Requirement (P 401)

A resource adequacy requirement is a mandatory component of the Commission's market power mitigation plan While the Commission acknowledges that this requirement does not prevent withholding, it believes that the requirement, by expanding the resource alternatives, reduces the ability of suppliers to exercise market power.

The ISO agrees that long-term resource adequacy (as a means to further long-term forward contracting) is a fundamental means to help reduce the opportunities for suppliers to exercise of market power. To the extent that load-serving entities forward-contract for sufficient capacity to satisfy their load, the ISO believes that a supplier's ability to demand high prices (*i.e.*, exercise market power) for power that it provides through an ITP's spot market will be greatly reduced.

The more important issue is how such forward contracts ensure the availability of resources procured under any resource adequacy requirement. The ISO believes that such details are best addressed by the load-serving entity and resource supplier, as overseen by the appropriate regulatory authorities, that enter into any such contract. At a minimum, the ISO believes that such arrangement must provide that a resource will be available for possible commitment by the ITP in the context of the ITP's day-ahead unit commitment process and, therefore, subject to any spot-market related penalties for non-performance in the context of those markets Penalties for non-availability in the forward-market timeframe should be addressed by the load-serving entity in any forward contract.

Finally, the ISO submits that any resource that is under contract to satisfy a resource adequacy requirement and is unavailable is likely to see, and should see, its future qualification (MW of capacity) to provide that service diminished or "derated" in the future. Such an approach, which is similar to the approach in place in the Eastern independent system operators, should provide further incentives for that resource to be available on a daily basis.

B. Local Market Power Mitigation (PP 411-412)

1. Participating Generator Agreements (P411)

The Commission proposes to require that all generators dispatched by the ITP enter into participating generator agreements ("PGAs") that would include provisions to mitigate local market power. In other words, each PGA would specify the explicit conditions under which a unit would be subject to local market power mitigation and the terms of the mitigation (*e.g.* specific bid caps) In particular, there would be a "must offer" requirement that applies when units are needed for reliability purposes or when non-competitive conditions arise. The Commission invites comment on how to structure the local market power mitigation and, in particular, on (1) how to define the noncompetitive conditions that should trigger the mitigation, and (2) how bid caps should be structured for generators operating under a PGA. As an alternative to using PGAs, the Commission suggests that local market power can be mitigated through bilateral contracts between LSEs and generators.

The ISO believes that the Commission's specified "contractual approach" to mitigating local market power is problematic in the following respects.

1. It assumes that the ITP can perfectly forecast, prior to executing the PGAs, all of the conditions that would confer local market power on a resource, and consequently can perfectly predict the areas where local market power is apt to exist and accurately assess the potential frequency and magnitude of the problem so as to provide adequate protection within the terms of the PGA. The ITP would have no recourse if it executes a PGA with a unit under the assumption that the unit would not have local market power if the unit, due to changing market conditions, subsequently develops significant local market power
2. It is unclear how the local market power mitigation terms and conditions in the PGA are determined. If these terms are determined through negotiations between the ITP and the generator owner, the ISO is concerned that negotiations for units needed for local reliability, will in the near-term (1-3 years out) be prone to market power abuse. The ISO has similar concerns with respect to the ability of LSEs to negotiate bilateral contracts with generators in constrained areas.

Alternatively, the ISO believes it is appropriate to specify some generic conditions or formulations applicable to all PGA agreements that would specify the conditions under which units would be determined to have local market power and the specific bid mitigation that would apply. The ISO believes the simplest and most appropriate approach to local market power mitigation is an approach where non-competitive regions are identified *a priori,* and anytime bids are taken out of sequence within a non-competitive region, they are mitigated to a predetermined level. Consistent with the approach that the Commission has approved for PJM, the predetermined level should be the resource's variable cost. *See Atlantic City Electric Company, et al*, 86 FERC ¶ 61,248 at 61,898-03 (1999); *PJM Interconnection, L.L.C.*, 96 FERC ¶ 61,233 (2001). The mitigated bid would be eligible to set the locational price In cases where local congestion is frequent, and a variable cost-based mitigated price does not allow recovery of annual fixed costs, a fixed-cost compensation mechanism could be negotiated with appropriate regulatory review and approval. Based on the level of fixed-cost compensation ultimately agreed to and/or approved, LSEs within the area could then determine if there are cheaper alternatives to paying the annual capacity contracts (*i.e* transmission, new generation, and/or demand response).

While this is the ISO's preferred approach for addressing local market power, an alternative approach that may have some merit is the NYISO local AMP procedures where locational conduct and impact thresholds are defined based on the expected frequency of congestion and the average annual prices at each location such that the exercise of local market power would not increase average annual prices at each location more than two percent.[23] *See New York Independent System Operator Corporation, Inc.*, 99 FERC ¶ 61,246 at 62,046 (2002). Under this approach, resources that violate the conduct and impact thresholds would be mitigated to a competitive bid-based reference level. However, the AMP procedures may increase costs to consumers as a result of the exercise of local market power being exercised up to the permitted thresholds.

2. Penalties for Forced Outages (P 412)

The Commission identifies the following three options for dealing with the risk of a forced outage inside a load pocket: (1) holding back some day-ahead capacity to reflect forced outage risk in real-time; (2) allowing must offer generators to bid in real-time instead of the day-ahead; and (3) if a generator receives a capacity payment, the generator bears the risk of the forced outage (and if the generator does not receive capacity payment, then the generator would not

[23] Care must be taken in defining "average annual prices" so that such concept is bounded by costs rather than solely determined by hours when the market is deemed competitive A peaker in a local area may only bid during tight system conditions, thereby setting reference prices that are excessive given local constraints In designing an effective local market power mitigation mechanism, the Commission must ensure that no significant market power is built into the average annual price

bear the risk of a forced outage). The Commission requests comment on the penalty that would be appropriate to deter unjustified forced outages.

The ISO supports Option 3. There need to be adequate measures to address physical withholding under the pretext of a forced outage (*e.g.*, if forced outages of a unit of a specific type or age appears excessive compared to the high end of forced outage in that class of units). The ISO notes that, although the Commission contemplates a penalty for unjustified forced outages, the Commission has not specified the appropriate criteria for determining whether a particular forced outage is "unjustified". The Commission has approved a list of factors the ISO can consider in determining whether a forced outage was intended to manipulate the market or is the result of other questionable behavior by the operator. *See San Diego Gas & Electric Company v Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange, 98 FERC* ¶ 61,202 (2002). The Commission should consider adopting the criteria it has approved for the ISO.

Falsely reporting a unit as being de-rated or forced out of service is a form of physical withholding and must be penalized. *See* New York Independent System Operator Market Monitoring Plan, Addendum A, Section 2.3(a)(1) (physical withholding includes falsely declaring that an Electric Facility has been forced out of service or otherwise become unavailable);[24] NEPOOL Market Rules & Procedures, Section 13 4 2.2 (misrepresentations regarding the inability or restricted ability of a resource to perform, including any statement as to the existence of a forced outage, are subject to penalty).[25] The ISO will propose in its Oversight & Investigation Tariff Amendment to be filed with the Commission in the near future that such

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[24] This tariff provision was approved by the Commission pursuant to an order issued on March 29, 2000 in Docket Nos ER97-1523, *et al. New York Independent System Operator, Inc* 90 FERC ¶ 61,317 (2000).

[25] This tariff provision was approved by the Commission pursuant to a December 17, 1998 order in Docket Nos OA97-237, *et al. New England Power Pool*, 85 FERC ¶ 61,379 (1998)

behavior be subject to a penalty. The Commission should approve the ISO's proposal consistent with its decisions in prior proceedings.

C. The Safety-Net Bid Cap (PP 413-414)

1. Appropriateness of a Regional Cap (P 413)

The Commission requests comment on whether the safety-net bid cap should be uniform across an interconnection, so that there would be one cap applicable in the East and another applicable in the West.

The ISO supports adoption of a uniform bid cap across an interconnection, whereby each ITP market in a region has the same bid cap, and such bid cap applies both to internal and external resources. A uniform bid cap is essential in order to avoid "megawatt laundering" and ensure efficient arbitrage where power is diverted from the lower priced market to the higher priced market.

As the Commission recognizes in the NOPR, seams problems can arise when there are different pricing rules in neighboring regions NOPR, Appendix C at 23. For example, when prices in the West were high, for a short period of time the Commission applied price mitigation to generators located in California for spot market sales in California. The same price mitigation measures did not apply to generators located outside of California. As a result, some California generators sold power to parties outside of California that then sold the power back into California at prices that were not subject to mitigation This practice was dubbed "megawatt laundering". Thereafter, the Commission applied uniform mitigation measures throughout the United States portion of the Western interconnection in order to remedy the problem. *See San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated By the California Independent System Operator and the California Power Exchange*, 95 FERC ¶ 61,418 (2001)("June 19 Order"). This uniformity of pricing rules was necessary to eliminate "megawatt laundering" concerns. In order to minimize seams issues and discourage "megawatt laundering", the same safety-net bid cap should apply throughout the West

The Commission has previously recognized that the California market is integrated with those of other states in the WSCC and that regional solutions are a necessary part of any long-term restructuring of the Western marketplace. *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent Operator and the California Power Exchange*, 97 FERC ¶ 61,275 (2001). In particular, the Commission has found that there is an interrelationship between prices in California and prices outside of California. *Id.* Because the Western market is integrated, the Commission should establish the same safety-net bid cap for all Western markets.

2. Level of the Bid Cap (P 414)

The Commission seeks comments regarding how it should determine an appropriate value for a bid cap. The Commission notes that safety net bid caps of $1,000/MWh are in place in the Northeast U.S.

The ISO believes that it is imperative that the level of the cap be based on an assessment of the extent to which markets in a region are workably competitive The Commission must ensure that, to the extent there are structural deficiencies in the market and/or a supply-demand imbalance that enable suppliers to exert market power on a sustained basis or otherwise engage in market power abuse, the bid cap is set at a level low enough to provide adequate protection to consumers, but not so low as to dull price signals for new generation investment and demand response.

For example, in numerous orders, the Commission found that the imbalance of supply and demand in California was a major cause of the unjust and unreasonable prices that were experienced in California. June 19 Order at 62,546, 62,549, *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and California Power Exchange*, 93 FERC ¶ 61,121 at 61,349 (2000)("November 1 Order"). As a result, the Commission found that it was necessary to adopt fairly restrictive price mitigation measures. As recently as July 17, 2002, the Commission has acknowledged that there is insufficient generation capacity in California and that additional generation is necessary. *California Independent System Operator Corporation,* 100 FERC ¶ 61,61,060 at 61,232-34, 61,239 (2002). In determining the appropriate level of the bid cap, the Commission must consider the balance between supply and demand For example, the Commission could evaluate the amount of available capacity (after accounting for suppliers' obligations to serve load and sales contracts) compared to regional demand and operating reserve requirements. The greater the imbalance is between supply and total demand/operating reserve requirements, the lower the bid cap should be However, as discussed in greater detail below, given the dramatic impact hydro conditions have on market competitiveness, one must use caution in assessing the competitiveness of the market if the index is largely based on a wet hydro season.

A factor the Commission should consider in determining the appropriate bid cap level is the nature of the resource mix in the region. For example, in the West hydro resources constitute a significant percentage of the overall supply. The amount of hydro capacity and energy that will be available each year is not predictable In 2002, there was a surplus of hydro generation. This contributed to the lower prices experienced in California in 2002. However, in 2000 and 2001, the amount of hydro generation was significantly lower, and prices reflected the significant exercise of market power under tight supply conditions. This demonstrates how, in the West, hydro reserve levels clearly have an impact on price. In regions that rely on weather-dependent resources such as hydro, the Commission must exercise more caution in establishing a bid cap One year there may be adequate supplies, but the very next year there could be tight supply, thereby allowing suppliers to be "pivotal" in setting prices Because of California's dependence on hydro generation, a wet year may yield actual market prices over a 12-month period that are approximately equal to estimated competitive prices. While this would be an indication that the prior 12 months were workably competitive, it would not necessarily be the case prospectively under a dry hydro year.

The ISO submits that it would be inappropriate to establish a uniform, safety net bid cap nationwide. The level of the bid cap should reflect market conditions in the particular region where the bid cap will apply. The Commission has recognized regional differences in the past in setting damage control bid caps and should continue to do so in the future For example, the Commission has approved a $250/MWh bid cap in California (in recognition of the supply-demand imbalance that exists there), while approving a $1,000/MWh bid cap in the Northeast. Although the eastern independent system operators have a damage control bid cap of $1000/MWh, the ISO does not believe that this is an appropriate level for the California market due to the fact that the structural elements necessary to ensure a workably competitive market do not exist in California The ISO does believe that over time, as market conditions improve, the safety net bid cap could eventually be raised. In no event should a safety net bid cap automatically (and arbitrarily) be imposed absent an evidentiary finding that competitive conditions exist in California to justify such an increase.

The Commission has expressly found that the California wholesale energy market is dysfunctional and "seriously flawed." November 1 Order at 61,349, June 19 Order at 62,546 The Commission has expressly found the prices in California's wholesale energy market to be unjust and unreasonable. *See San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into the Markets Operated by the California Independent System Operator and the California Power Exchange,* 93 FERC ¶ 61,294 at 61,998 (2000); 95 FERC ¶61,115 at 61,351, 61,360 (2001); 95 FERC ¶ 61,418 at 62,549, 62,565 (2001); 97 FERC ¶ 61,275 at 62,218 (2001). Further, the Commission has been presented with evidence of "gaming" and manipulation in the California energy market, and both the Commission and the U.S Attorney's Office, currently are investigating the manipulation of energy prices in California by various suppliers. In addition, two Enron employees have been indicted on fraud charges (and pled guilty to charges of conspiracy to commit wire fraud) in conjunction with activities involving the California markets.

None of these circumstances exist in the eastern markets. The 2001 "Annual Report on the New York Electricity Markets" dated April 16, 2002 states at page two that "[a]nalysis of the market conduct of both suppliers and the load-serving entities indicates that the markets have been workably competitive." The "PJM Interconnection State of the Market Report" dated June 2002 indicates at page one that "in 2001 the energy markets were reasonably competitive." A "Competitive Analysis of the Energy Market in New England" prepared by the Independent Market Advisor to ISO New England in May 2002 notes at page ii "New England markets have been workably competitive and produces little evidence of persistent economic or physical withholding." A $1,000/MWh safety net bid cap may be justifiable in the East where workable competition exists. However, workable competition does not yet exist in California, and the Commission has not found otherwise

A significant difference between the ISO and the Eastern independent system operators is the supply-to-demand imbalance that exists in California. As indicated above, the Commission has recognized that there is inadequate supply in California. *See, e.g.*, June 19 Order at 62,546. The Commission has not made similar findings with respect to the Eastern independent system operators. In fact, the reserve margins in the markets operated by the independent system operators are considerably higher than the reserve margins in California.[26] Moreover, the Commission has recognized that reserve margins in the Western Electricity Coordinating Counsel have fallen to only 10 percent, the lowest in the nation. *California Independent System Operator* Corporation, 100 FERC ¶ 61,060 at 61,232 (2002). Because there is a supply-to-demand imbalance in California, there exists a greater opportunity for suppliers to exercise market power than exists in the East.

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[26] For example, the New York State Reliability Council established a statewide annual Installed Capacity Requirement of 18 percent for the period May 2002 through April 2003 This decision resulted in an Installed Capacity Requirement implemented by the New York ISO equal to 118 percent of forecasted peak load. On the other hand, the ISO's 2002 Summer Assessment showed an expected reserve margin of only 3 4 percent.

Furthermore, as the Commission has recognized, the reliability of California's electric system depends in large part on imports from generation located in neighboring states to meet load requirements [27] November 1 Order at 61,357. The eastern independent system operators such as PJM do not have such a reliance on imports. *See "East vs. West: Comparing Electric Markets in California and PJM,"* Public Utilities Fortnightly, p. 26 (June 15, 2000) (recognizing that PJM is a self-contained system and California is a net importer of power). The decline in imports bidding into the real time market makes California's supply-to-demand balance even more precarious and militates against approval of a high safety net bid cap.[28] In that regard, the absence of competition from imports only creates more favorable conditions for in-state suppliers to exercise market power.

Finally, unlike the eastern independent system operators, the ISO currently does not have any mechanism designed to encourage LSEs to enter into forward contracts In that regard, each of the eastern independent system operators imposes an installed capacity ("ICAP") or similar obligation on LSEs based on LSEs' peak load requirements

Until a mechanism is put in place to encourage forward contracting (and the construction of new generation), and California's supply-to-demand imbalance is corrected, there is no basis to implement a $1,000/MWh safety net bid cap in California. Such a high level would result in consumers being subjected to unjust and unreasonable prices. Absent affirmative findings that the factors described above have been remedied and that a competitive market exists at all times and under all conditions, the Commission cannot lawfully raise the safety net bid cap in California to the levels in use in the East.

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27 California's import capability is approximately 8,000 MW.

28 Further, because a substantial portion of the electricity being imported into California is from hydroelectric facilities, California is at the mercy of hydro reserves that vary from year-to-year

D. Mitigation Triggered by Market Conditions (PP415-417)

1. Temporary Market Power (P 415)

The Commission notes that certain kinds of events (*e.g.* extreme supply or demand conditions) that are transitory can provide opportunities for suppliers to exercise market power even in a market that is normally workably competitive The Commission states that it may be appropriate for other conditions to trigger this mechanism. The Commission seeks comments on what these triggers should be

The ISO supports adoption of two separate and distinct market power mitigation measures: one that would apply to "unanticipated" market conditions that would provide suppliers with the opportunity and the incentive to exercise market power on a "temporary" basis; and one that would apply during market conditions where suppliers can exercise market power for a "prolonged" period. These are two distinct types of circumstances and, as such, require different types of mitigation.

As the Commission recognizes, these types of conditions might include the loss of significant hydro capacity because of drought or *force majeure* events such as a major transmission line outage or the forced outage of a major generating unit(s). Further, market power has been exploited not only during system peak conditions, but also during off-peak months when scheduled and unscheduled outages have led supply shortages. Often it is the relationship between available supply and current demand that creates the opportunity for the exercise of market power In 2001, the ISO shed firm Load on January 17, January 18, January 21, March 19-20 and May 7-8 These emergencies occurred when system demands were below summer peak demand. However, due to planned and unplanned outages, the ISO experienced significant supply shortages. Similarly, the overwhelming number of 137 Stage 1 emergencies, 107 Stage 2 emergencies and 39 Stage 3 emergencies experienced by the ISO in 2001 occurred prior to May. Another example, which is reflected in Attachment A to the ISO's June 17, 2002 Answer to Protests in Docket No. ER02-1656, is November 2001 where prices brushed up against the bid cap in 20 percent of the BEEP intervals. November is generally a period of low hydro generation and, when hydro generation is low, prices generally increase dramatically This demonstrates that it is imperative that the Commission adopts some sort of *mitigation mechanism that can apply during seasons where there are low hydro conditions and* times when there are major transmission or generation outages. Under these circumstances, suppliers in the California market have the opportunity to exercise market power "temporarily"

The Commission indicates that an AMP-like mechanism similar to those approved for the ISO and the New York Independent System Operator could address situations in which market power can be exercised on a "temporary" basis. The ISO concurs that this provision is an important element, particularly in markets that lack the structural elements to support a workably competitive market However, in order for an AMP- like mechanism to provide meaningful protection against the "temporary" exercise of market power, the trigger thresholds must be set at reasonable levels. The ISO believes that the AMP thresholds the Commission has approved in California are too high to provide any significant protection against market power These thresholds permit suppliers to submit bids that are double or even triple their reference prices before there is any possibility of price mitigation. Loose thresholds such as these are particularly inappropriate in regions such as California where robust competition does not exist in general and markets are even less competitive during periods of low hydro conditions.

The ISO also submits that it is appropriate and necessary for the Commission to adopt *separate "conditional" mitigation measures (e.g., cost-based bids) – as a substitute for or as a* supplement to AMP –that would apply during conditions in which suppliers have the ability to exercise market power for a prolonged period[29] In that regard, regions such as California rely extensively on weather dependent supplies such as hydro that can vary dramatically from year-to-year. In the event of a prolonged drought, available hydro supplies could be dramatically reduced for several years. For example, it is not uncommon for prolonged droughts to last several years as was the case prior to 2002. As indicated above, when hydro supplies are plentiful, prices in California are more competitive because there is increased competition in the market. On the other hand, when hydro supplies are low, prices increase because the number of competitive alternatives decrease, and non-hydro suppliers are well positioned to exercise market power. AMP is ineffective and inadequate under conditions where suppliers can exercise market power for a prolonged period of time.[30] Accordingly, some other type of market power mitigation measure needs to be triggered under these circumstances.

AMP is inadequate in situations of prolonged resource inadequacy or unavailability In that regard, AMP reference prices in California and New York are primarily based on 90-day rolling averages of accepted bids A combination of overly generous conduct and impact thresholds and a bid-based reference price can render AMP ineffective during periods of sustained noncompetitive markets. For example, if drought conditions persist for any significant length of time, non-hydro resources would be able to increase their bids in a consistent manner (thereby ratcheting up their reference prices correspondingly) due to a lack of competition AMP does not provide adequate protection under these circumstances, and prices will continue to

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29 The ISO recognizes that determining the appropriate triggers for any mitigation would require the Commission carefully to analyze the level of available supply and demand and operating reserve requirements. The Commission might set the mitigation trigger based on a specified threshold such as the 12-month market competitiveness index proposed by the ISO in MD02 or specific supply conditions such as levels of hydro availability or a specified amount of capacity being unavailable due to prolonged outage

30 Other conditions that could create opportunities for suppliers to exercise market power for a prolonged period include (1) significant unforeseen load growth and (2) expected generation failing to materialize (or any other period in which there is not adequate available generation).

spiral up until drought conditions cease and some semblance of competitive balance is restored. Under such conditions, the Commission should lower conduct and impact thresholds and make reference levels cost-based rather than bid-based.

2. Mitigation Triggers (P 416)

The Commission requests that parties identify (1) the market conditions that should exist for this type of mitigation to be triggered, and (2) the conditions that are necessary for the mitigation to be suspended.

The ISO does not agree with the Commission's assertion that AMP-like mechanisms should be temporary and suspended once competitive conditions are restored. System conditions are dynamic, and protective measures must be in place continually so that consumers will not lose confidence in a competitive electric market. It may be that if competitive conditions are maintained, AMP will never be triggered, but it is important to have such transparent thresholds in place Further, AMP thresholds can be relaxed if the market has been demonstrably workably competitive for a specified period of time. The ISO's proposed 12-Month Market Competitiveness index is one measure for gauging the competitiveness of the market However, as noted above, the Commission must be mindful in reviewing such an index that market performance under a wet-hydro season can be markedly different under a dry-hydro season. A prospective time-differentiated Residual Supply Index ("RSI")[31] analysis under varying hydro conditions may be an additional tool for assessing the potential for future market power.

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[31] The RSI screen measures the ratio of residual supply (total supply minus the capacity of the supplier) in question to the actual system demand (load plus operating reserves) The RSI screen is discussed in greater detail in the ISO's Comments Regarding the Supply Margin Assessment Screen and Related Mitigation Measures filed on October 24, 2002 in Docket No PL02-8 The ISO urges the Commission to adopt the RSI screen to test for suppliers' market power in the future.

E. Establishing Bid Caps or Competitive Reference Bids (PP 418-427)

1. Adder for Default Bids (P 420)

The Commission notes that there are choices in setting default energy bids including some average of previously selected bids, a measure of operating costs adjusted for fuel costs, or through negotiation. The Commission states that the ITP may put an adder in to reflect a margin above operating costs (possibly to reflect opportunity costs) The Commission requests comment on whether the level of the adder should be reviewed on a region-by-region basis or if the Commission should establish a uniform adder, and if so, at what level.

The ISO supports establishing default bids based on cost measures that would include some measure of operating cost adjusted for fuel costs (using a monthly index price resistant to manipulation). Using bids in previous periods as a reference price for mitigation purposes when a unit is needed for local reliability purposes can lead to distortions in a firm's bids during such hours. In that regard, a firm's bids might be influenced by a desire to establish a higher reference price that can be charged during periods when the unit has local market power and is needed for reliability purposes. Similarly, basing reference prices on bids provides little constraint on high cost peakers. Such units may bid only a few days in a year and may bid up to price cap of $1000/MWh. Because they rarely bid and always bid at high levels, the reference price can be as high as $1000/MWh even though their variable cost is less than $100/MWh A large supplier with a portfolio of supply resources can deliberately set aside a unit like this to bid at a high price whenever it needs to set high prices. Therefore, some form of cost-based reference price is needed for certain units. A variable cost based reference is appropriate when there is some form of resource adequacy mechanism in place that provides a capacity payment to these units to recover their fixed cost

The ISO believes that that any adder to a firm's cost basis should be developed on a supra-regional basis. There can be different regional costs, competitive circumstances and/or other conditions that should be considered in determining the appropriate level of any adder

These regional differences would not be reflected in a uniform, nationwide adder As an initial matter, the ISO believes that the 10 percent adder used in PJM is reasonable and allows more than enough flexibility to recover any uncertain costs. *See Atlantic City Electric Company, et al.*, 86 FERC at 61,899. Also, it must be recognized that any cost-based reference price would apply only during limited periods when a unit it needed for local reliability purposes. During all other periods, the unit can receive a market-based price for its power. Again, the adder only needs to be high enough to recover variable costs when a capacity payment is in place to assure fixed cost recovery. The Commission should not consider any argument to raise the adder based on fixed cost recovery.

2. Peaking Unit Bid Caps (P 421)

The Commission notes that many peaking plants set the MCP, which may not allow a margin for those plants to recover some of their fixed costs. The Commission states that the average cost of a new peaking unit at a given location operated over a given number of hours could form the basis for setting such a premium. This kind of adjustment to bid caps for peaking units could help support reliability until demand-side measures for responding to price were more fully incorporated in markets. The Commission requests comments on whether this approach or other adjustments to bid caps for peaking units might usefully substitute for demand response in the near term

The ISO opposes adding a premium to a peaking unit's bid cap as a means of ensuring the unit owner recovers its annual revenue requirements. There are more appropriate avenues for ensuring annual revenue requirement are recovered such as capacity payments in the ancillary service markets and long-term bilateral **capacity** contracts with LSEs or RMR contracts with the ITP.[32] Including such a premium would distort the intended outcome of the mitigation, which is to produce prices that reflect a competitive market. With the exception of periods of true scarcity (*i.e.* insufficient supply to meet demand), prices in a competitive market should reflect the "marginal variable cost" of the highest cost unit dispatched. In most local reliability areas, there is generally sufficient supply to meet demand but not enough suppliers to make the market competitive. If, under such situations, a peaking unit is frequently on the margin at its mitigated bid cap and unable to recover its annual fixed costs--including any market revenue it derives from the ancillary service market-- the unit owner can rightfully threaten to exit the market unless it is provided annual capacity payments to cover its annual costs Under these circumstances, the LSE or ITP receiving the reliability service will need to decide whether to provide such payments or find alternatives means for meeting the reliability need.

3. Energy Limited Resources (P 422)

The Commission states that it appears unnecessary to cap energy bids from energy limited resources (hydro and other energy-limited resources) below the safety-net bid cap as long as their bids to provide operating reserves were always in-merit order Alternatively, other energy-limited resources might be allowed to submit a bid that states a total megawatt-hour availability over the day and allow the market operator to schedule the power from the unit in the hours when the price is highest. The Commission requests comments on these and other approaches to establishing reasonable caps for energy bids.

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32 In particular, owners of peaking units can seek recovery of fixed costs through either the forward contracts they enter into with LSEs as part of a resource adequacy mechanism or through ITP/third-party facilitated /capacity markets Indeed, the Commission itself has stated that the primary means by which generators should recover their fixed costs is through bilateral contracts, not through the spot market. *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange,* 95 FERC ¶ 61,61,115 at 61, 364 (2001)

It is possible for the ITP to accommodate the service contemplated by the Commission. However, it is *necessary to guard against physical withholding strategies (e.g.*, submitting low MWh availability over the day from resources that are not really energy limited).

The ISO believes that the approaches proposed by the Commission generally fit within the market power mitigation framework. Specifically, the Commission proposes a general framework that would only impose unit-specific bid caps during instances of local market power or through an AMP mechanism in markets that are not workably competitive. In either case, the Commission's first recommendation for energy-limited unit specific bid caps is essentially no bid cap at all. Such an approach runs contrary to the basic concept of market power mitigation. If *an energy limited resource is operating under conditions (local or otherwise) that enable the* resource to exercise market power, there is no legitimate reason why the Commission should not impose unit specific bid caps. With regards to the alternative recommendation -- having the generator submit a daily energy budget to the ITP and the ITP optimize that budget across the day-- the ISO is unclear how this suggestion relates to the determination of unit specific bid caps. If the Commission is suggesting that energy limited resources not be allowed to specify a bid price in the ITP markets and instead be a price taker, the ISO is concerned that such approach, while certainly addressing the bid cap problem, would be inappropriate for the following reasons. First, forcing energy limited resources to be price takers may result in less energy being offered to the market because the price received for such energy may not be compensatory relative to the resource's temporal opportunity costs. For example, in California, which relies extensively on imported energy, the Commission previously imposed a requirement (which requirement subsequently has been eliminated) that imports must bid $0/MWh and be price takers. *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange*, 97 FERC ¶ 61,275 (2001). Following this ruling, imports into California dropped dramatically. *See* Fourth Quarterly Report of the California Independent System Operator

Corporation, Docket Nos. EL00-95-000, *et al.*, at 10 (June 14, 2002); Third Quarterly Report of the California Independent System Operator Corporation, Docket Nos. EL00-95-000, *et al.*, at 22-23 (March 26, 2002). Second, optimizing the scheduling of a hydro system involves consideration of more factors than a daily energy budget and prices. There may be a number of intra-day constraints and inter-unit constraints (*e.g.* watershed management issues) to consider The ISO believes such considerations are better left to the unit owner.

In general, the ISO agrees that unit bid caps for energy-limited resources ought to reflect inter-temporal opportunity costs. The ISO's preferred approach for determining inter-temporal opportunity costs is to base it on the accepted bids from such resources during competitive hours in the previous 90-days. In the event such bids are not available, inter-temporal opportunity costs for each energy-limited resource could be determined by the ITP monitoring unit in consultation with the unit owner by developing a forecasted price duration curve for the coming year or season. Inter-temporal opportunity costs could then be determined through intersecting the number of hours that an energy-limited resource can run with the forecasted price duration curve.

4. Seasonal/Monthly Schedules (P 423)

The Commission suggests having an owner of hydro and other energy-limited resources submit to the ITP a seasonal or monthly schedule for when such units would not be expected to run as an alternative to developing unit specific bid caps for such units. The Commission states that the ITP is expected to continue to perform this outage coordination function under Standard Market Design. The Commission suggests that scheduling outages in advance, coupled with auditing by the market monitor, would provide a way to evaluate whether failures to run were from withholding or legitimate limitations. For hydro units, whose marginal costs are primarily opportunity costs, the Commission believes that this method may be a sufficient check against withholding so that it might be unnecessary to have a bid cap for these units.

The ISO does not understand how the Commission's suggestion negates the need for unit-specific bid caps for hydro resources. During a period when an energy-limited resource is expected to run and has local or global market power during tight supply conditions, such market power needs to meet mitigated to some extent. It is unjust and unduly discriminatory to impose bid caps on fossil fuel units during periods in which they can exercise local market power, but not to impose any type of bid cap on hydro units under similar conditions. Market power is Market power regardless of the type of unit that is exercising it. It might be appropriate to impose a different type of bid cap on hydro units than fossil fuel units, but some type of bid cap is both appropriate and necessary. The ISO agrees that having energy-limited resources provide seasonal and monthly availability plans to the ITP is appropriate, and the ITP's review and approval of such plans would help to mitigate physical withholding. However, such an approach will not mitigate economic withholding. Unit-specific bid caps are needed to address economic withholding.

5. Bid Caps for Regulation Service and Operating Reserves (P 424)

The Commission requests comment on how to identify the options for determining competitive bid caps for regulation service and operating reserves, including availability bids, that should be established for day-ahead and real-time markets.

The ISO believes that the approach proposed in the ISO's MD02 filing provides an appropriate mechanism. Specifically, In its MD02 filing, the ISO proposed to price Ancillary Services ("A/S") capacity based on the sum of the opportunity cost (which would be based on submitted energy bids) and a capacity bid that would reflect the unit owner's cost (wear and tear, increased maintenance costs etc.) Under this approach, unit-specific capacity bid caps could be established based on a periodic assessment of the actual costs of providing A/S capacity. Such costs would not include an annualized fixed costs of equipment necessary for providing A/S capacity (e g Automatic Generation Control equipment) as such cost are "sunk" and, therefore, should be recovered through the infra-marginal market revenues earned in the

A/S capacity market. Presumably, the provision of regulation service would have higher costs than the provision of operating reserve due to the fact that units on AGC are apt to be ramped up and down more frequently than units providing operating reserve. These periodic assessments should be performed by the market monitor in consultation with the unit owner.

6. Unit Specific Bid Caps (P 426)

The Commission proposes that unit-specific bid caps should be established for other bid parameters such as bids for start-up and no-load costs and a variety of other bid-in operating parameters such as low and high operating levels and minimum run times. The Commission proposes several approaches for establishing caps for these particular parameters One suggested option is to rely on engineering data relating to the operating characteristics of the specific type of unit to determine bid caps. The Commission identifies PJM's approach that permits changes to these parameters once every six months as possibly a simpler alternative that does not unduly restrict competitive generator behavior The Commission requests comments on this approach and on other ways (like using engineering estimates for technical parameters and cost-based bids on start-up and minimum load) to prevent sellers from manipulating these bids and operating parameters to increase market-clearing prices and uplift payments.

The ISO believes that both the determination of bid caps for start-up and minimum load costs according to engineering cost data and the PJM approach are both viable approaches However, the ISO suggests that other operating parameters, such as low and high operating levels, ramp rates, and minimum run times should be based on engineering data and subject to verification and certification by the ITP. Because start-up and minimum load costs do not impact the MCP, they must be compensated by uplift payments to the extent the MCP does not provide adequate market revenue to cover them. The uplift payment would be intended to ensure the winning bidders do not lose money; thus, such payments are meaningful only if the start-up and minimum load costs are cost-based.

This is ISO's approach in its MD02 proposal Specifically, under the ISO's residual unit commitment proposal, suppliers can submit market-based bids for the energy portion of their three-part bid and those energy bids can reflect opportunity cost for energy-limited resources. Only the start-up and minimum load are cost-based. The Commission has already approved cost-based pricing for start-up and minimum load costs in connection with the Must Offer obligation in California. *California Independent System Operator Corporation,* 97 FERC ¶ 61, 293 (2001). Pricing of start-up and minimum load costs for the purpose of bid caps should be the same under either a "must offer" or unit commitment obligation. Moreover, if the ISO had not committed the resource, the resource would be shut down and not have earned anything, so it is equitable that a resource committed by the ISO earn its costs, but not earn a windfall profit so as to discourage self-commitment.

If the Commission does require an ITP to adopt market-based start-up and minimum load costs, resource owners should only be allowed to change those bids once every six months as in PJM. Allowing resource owners to submit market-based start-up and minimum load bids on a daily basis will likely exacerbate market power problems during high load periods when the ISO essentially needs to commit all available resources in the control area.

7. Bid Cap Determination (P 427)

The Commission requests comment whether the Commission should establish a formula for determining the bid caps or whether the Commission should review the proposals developed in each region.

The ISO believes that the Commission can provide some general guidance regarding the determination of bid caps; however, the Commission should allow for regional flexibility in developing the specific methods used to derive unit specific bid caps as well as in the level of the caps themselves. Costs, the resource mix and competitive conditions vary from region to region. The Commission should allow each region to propose an applicable bid cap based on the specific conditions that exist in the region. Such an approach is more likely to foster new and innovative approaches to addressing this challenging problem. The Commission will have an opportunity to review each region's approach and, over time, may be able to specify a "best practices" approach that could be adopted as a standard approach for all regions

F. Exemptions

The Commission suggests that sellers who control a small amount of capacity in the market (*e g.,* no more than fifty megawatts) would be exempt from mitigation. The Commission attempts to justify this concept by stating that sellers with minimal capacity would have little incentive to exercise market power since a non-competitive bid could eliminate their only unit from the dispatch. The Commission requests comment whether any other sellers should be exempt from the mitigation because they have insufficient incentives to withhold.

The ISO does not believe it is appropriate to exempt sellers having small portfolios from market power mitigation. Such sellers can still exercise market power during conditions when they are relatively certain the ITP will need to call on their capacity for local reliability reasons, and, therefore, will have an incentive to engage in economic withholding. The market impact of their behavior is not limited to their portfolio because they could effectively set the locational market clearing price. Moreover, such a seller might have affiliations or financial arrangements with other sellers that could create further incentives to exercise market power.

G. Monitoring (PP 429-456)

1. Status of Market Monitor (PP 429-430)

The Commission proposes that market monitoring should be conducted on an on-going basis by a market monitoring unit ("MMU") that is autonomous of the ITP's management and market participants. The Commission proposes that the MMU report directly to the Commission and the ITP governing board. The MMU would be accountable only to the Commission and the governing board, although it would share information with the ITP management and Regional State Advisory Committee. The MMU would have the responsibility to propose to the Commission and the ITP's Board changes to market rules if they provide inefficient incentives to market participants, and to identify circumstances that may require additional market power mitigation so that remedies can be put in place prospectively. For example, the Commission states that in the SMD implementation filing, the MMU would propose tariff language that sets forth the process for setting the bid caps for individual units or any formula that might be used for this purpose.

The ISO submits that the Commission needs to clarify further the role of the MMU and its relationship to the ITP. As written in the NOPR, the Commission's proposal is problematic.

The ISO understands the Commission's need to have access to data in order to monitor markets effectively However, the ISO opposes a MMU that reports directly to the Commission if such MMU entity is comprised of ITP employees. MMU employees cannot simultaneously serve as "agents" for the Commission (as the Commission would have it) and as employees for the ITP. Such an arrangement would create an irreconcilable conflict for the employees, *i.e.*, employees paid by the ITP but reporting directly to the ITP's regulator This conflict is further complicated by the fact that the Commission contemplates charging the MMU with monitoring and evaluating the operations and actions of the ITP. This would put ITP employees who are part of the MMU in an extremely difficult position.

If the Commission desires to have personnel to monitor and analyze the ITP's operations and the markets, then the Commission should utilize its newly formed Office of Market Oversight and Investigations ("OMOI"). Indeed, the Commission has already placed members of its OMOI in California by opening a field office in Folsom, California to monitor the ISO's markets. The Commission does not need a direct reporting relationship with a MMU comprised of ITP employees in order to obtain raw data from the ITP, the Commission can simply order the ITP to produce such information.

Furthermore, the ISO's market monitoring unit, the Department of Market Analysis ("DMA"), performs a number of functions for the company, including providing general economic advice to management and contributing to the development of ISO proposals. The ISO employees in DMA have been retained because of their expertise in economics and markets and are needed to provide broad economic advice to management, formulate proposals and assist in filings. The ISO's DMA is integral to management in providing advice regarding market design and policy options. If ITP/MMU employees were required to report directly to the Commission, the ITP would have to go out and hire additional employees to perform services currently provided by the MMU. In other words, the ITP will be hiring employees to perform duplicative work This will cause ITP costs to increase unnecessarily

The ISO understands that the Commission needs ready access to information relating to anomalous market events. The ISO also believes that market monitors should have the ability to report directly to the Commission the results of ongoing monitoring activities, including current market conditions and market participant behavior. However, the autonomy should be limited to those types of functions. A MMU comprised of ITP employees should not be answerable to the Commission for purposes of receiving assignments and conducting analyses. That function typically is reserved for the employer, and the ITP needs control of that function in order to develop proposals and exercise its Section 205 rights. Utilities have the sole right to submit proposals to the Commission. Direct Commission involvement with the MMU would cripple management's ability to independently develop Section 205 filings. Ultimately, it is the ISO management that is accountable to the Commission and its Governing Board, not the DMA Totally separating the DMA from ISO management would severely inhibit management's ability to develop supportable Section 205 filings before the Commission.

The ISO does not object to a truly autonomous entity (such as an outside auditor or the ISO's existing Market Surveillance Committee) reporting directly to the Commission and advising the ITP's board. For example, in an effort to ensure independent market monitoring, the members of the Market Surveillance Committee ("MSC") are not employees of the ISO. The MSC is an independent advisory group of industry experts. To provide for independence, none of the MSC's members are affiliated with or have any financial interest in any market participant.

Their charter allows them to suggest changes in rules and protocols or recommend sanctions or penalties directly to the ISO Governing Board and the Commission. The functions of the MSC include providing an independent review of market performance and market power problems, developing a record of structural problems and proposing corrective actions, and reviewing ISO rule changes, penalties, and sanctions.

As indicated above, the NOPR contemplates that the "autonomous" MMU can propose tariff changes in the ITP's SMD implementation filing and generally propose changes in market rules. Regardless of the organizational structure of the MMU, the Commission must clarify that the MMU's role will be advisory to the ITP (board and management) only and that the MMU cannot "dictate" the content of the ITP's tariff proposals. It is a basic tenet of the Federal Power Act that the regulated utility alone has the right to initiate a Section 205 tariff filing and determine the appropriate content of such Section 205 filing. *See Atlantic City Electric Company, et al. v. FERC,* 295 F 3d 1 (D C. Cir. 2002). Stated differently, a MMU, whether it is comprised of ITP employees or functions as a separate autonomous entity, cannot require the ITP to submit particular proposals for consideration by the Commission pursuant to Section 205 On the other hand, it would not be inappropriate for the MMU to advise the ITP regarding mitigation provisions and market rules such as the ISO's DMA and MSC do today. However, if the Commission chooses to adopt MMU proposals proffered by an "autonomous" MMU that differ from the ITP's filed tariff, the Commission must act pursuant to Section 206 of the Federal Power Act.

Finally, the ISO acknowledges and supports the efforts of the SSG-WI to develop West-wide market monitoring function. Whether that function ultimately resides in a single market monitor for the West or a coordinating body of market monitors that serves that same function[33], the ISO supports the need for effective and timely monitoring of the entire Western market. As the Western electricity crisis of 2000-2001 demonstrated, the deficiencies or problems of sub-regional markets cannot be self-contained within such markets, and the entire West effectively forms a natural market.

2. Monitoring of the ITP (P 432)

The Commission requests comment on whether the MMU should also be responsible for monitoring the ITP's operations, in addition to the markets and the market participants Specifically, the Commission asks whether the MMU should evaluate whether the ITP treats market participants neutrally, without undue discrimination.

The ISO believes that it is appropriate that an "autonomous" MMU not comprised of ITP employees monitor the ITP's operations in addition to those of market participants for actions that are not consistent with efficient or fair market outcomes. Such MMU should be responsible for monitoring all activity that could result in inefficient market outcomes. When inefficient market outcomes are the result of the actions of the ITP, the MMU should have the responsibility to raise its concerns immediately to the ITP board and FERC. The MMU should also be responsible for advising the ITP of new operating procedures that might improve the functioning of the ITP's markets and operations

[33] In the context of the SSG-WI discussions, the ISO supports the retention of local (*i.e* , individual ITP) market monitoring units that report to management. To the extent there is a supra-regional MMU, a more "local" market monitoring unit would be needed to "focus" on, and have expertise in, sub-regional market issues and identify specific problems or concerns in the particular sub-region Moreover, as previously stated, the ISO strongly believes that any MMU must have staff on-site at each ITP. DMA's ability to directly interact with ISO operating personnel has been invaluable. The Commission has obviously recognized that value by placing OMOI personnel adjacent to the ISO

As indicated above, if the MMU is comprised of ITP employees, it would not be appropriate for such MMU to monitor and evaluate the ITP's actions and operations The ISO believes that the Commission's OMOI, in conjunction with an inter-regional market monitoring function, could fulfill that responsibility

3. Regional Planning Process (P 434)

The Commission proposes that the work and findings of the market monitor must be integrated into the regional planning process The ISO agrees that the MMU must be integrated into the regional planning process so that market impact considerations are included. Traditionally, regional planning has focused primarily on the reliability effects of changes to the regional transmission grid and ignored the potential market impacts of such changes. However, the move to competitive wholesale electric markets has spawned the need to look closely at the impacts of transmission congestion on generation market efficiency and, in particular, the ability of strategically located suppliers to exercise market power. The MMU should be staffed with personnel that can identify market inefficiencies caused by transmission infrastructure problems and are able to analyze the potential market benefits of regional transmission upgrades that should be considered in addition to the reliability impacts of such upgrades.

As discussed earlier, SSG-WI is in the process of developing a recommended regional transmission planning process, a process that largely supports the objectives of the regional planning process outlined by the Commission in the NOPR. In fact, the focus of the developing SSG-WI planning process is the economic expansion of the Western high-voltage transmission system. Therefore, the SSG-WI effort will appropriately defer to each RTO's established planning process to ensure *reliability*-driven expansion of the grid (based on established WECC reliability standards) and will focus on furthering those transmission expansion projects needed to support an efficient and competitive Western electricity market.

To that end, the SSG-WI Planning Work Group is focusing on the further development and use of the criteria under development at the ISO for use in evaluating the need for economically-driven (as different from reliability-driven) transmission projects. The ISO has previously provided information regarding this project to the Commission.[34]

4. Market Monitoring Plan (PP 435-445)

The Commission proposes the basic elements of a market monitoring plan to be used by each market monitor. An important focus of market monitoring under the plan would be structural market conditions. The ISO agrees that structural market conditions are critical to understanding competitive regional bulk power markets and believes that such conditions should be a critical focus of the market monitor.

The Commission proposes to require each monitor to perform a structural analysis of the region that would include: (1) market concentration including by type of generation, (2) conditions for entry of new supply, (3) demand response, and (4) transmission constraints and load pockets that give sellers the ability and incentive to exercise market power. The Commission proposes that such analysis would be performed prior to the implementation of SMD, in order to implement the market power mitigation and would be performed annually to reassess and adjust the market power mitigation and to evaluate conditions in the market. The ISO agrees that each of the above listed items should be included in a structural analysis; however, the Commission should also include an analysis of regional supply reserve margins An examination of supply reserve margins is critical because when reserve margins are tight, even suppliers with minimal market share may have the ability to exercise market power to raise prices.

5. Assessment of Market Performance (P 441)

The Commission proposes to require an annual assessment of the performance of the markets operated by the ITP. This assessment would use a competitive benchmark to measure

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[34] See "Comments of the California Independent System Operator Corporation on the Commission's RTO Workshop - Lessons Learned After Three Years of Operation –" pp 12-20, filed on November 12, 2001

market performance as an additional means of determining the effectiveness of the market power mitigation. Comment is requested on how the monitor should address these and other topics, to develop useful measures that permit inter-regional comparisons.

The ISO *agrees that it is important to monitor the overall performance of the* ITP markets. Since 1999, the ISO's DMA has issued an annual report that assesses the performance of the ISO's markets and identifies issues that are either under examination or that need to be. The ISO understands that the other existing independent system operators also produce such reports and recommends that all ITPs' MMUs be directed to publish such reports. As important as annual overall market performance assessments is the development of standardized *metrics* to evaluate *ongoing* market performance. Annual reviews or assessments may not be sufficient or effective in quickly identifying and proposing remedies to market anomalies The ISO does not believe that the Commission's traditional "hub and spoke" analysis or its newer Supply Margin Assessment test are sufficient for this purpose and for application in a dynamic market environment.

One example of such an index or metric is the 12-month market competitiveness index ("12-month MCI") that was filed as part of the ISO's MD02 proposal. The 12-month MCI provides a means of continually monitoring the reasonableness of the prices produced in the competitive wholesale market and the effectiveness of any mitigation measures The ISO notes that its MSC has "strongly endorse[d] the concept of a rolling 12-month competitiveness index." *See* "Comments of the Market Surveillance Committee of the California ISO on the Proposed *October 1, 2002 Market Power Mitigation Measures*" Attachment V *to the* ISO's May 1, 2002 MD02 Filing in Docket No. ER02-1656

The ISO has tested this index to see if use of such an index could have averted much of the damage that occurred during the California energy crisis in 2000 and 2001. During the first two years of in the restructured California power markets, market costs were no more than seven percent above an effective competitive market outcome, even though there were occasional price spikes as high as $9,999/MWh. However, in May of 2000, after repeated price spikes, the rolling average cost of electricity surpassed the allowable $5/MWh mark-up above the average effective competitive market outcome. If the proposed standard had been in place, pre-authorized market power mitigation measures could have been implemented at that time. Without this explicit standard, however, California consumers were subjected to approximately one year in which the 12-month rolling average market costs were 40% or more above the effective competitive market outcomes. The effects of that year were catastrophic

One of the key features of the 12-month index is that it provides certainty and confidence for all market participants. Consumers would know in advance the level at which regulators would intervene to prevent market abuse. Power suppliers would be aware of when mitigation measures would be triggered and would have the opportunity to self-regulate their bidding practices in order to avoid regulatory intervention, and the Commission would have an objective standard to know when impose price mitigation measures Thus, use of such an index would be consistent with and further the Commission's goal of establishing ex ante mitigation measures.

Even though the Commission might adopt some screen for assessing market power, any such screen will not and cannot be perfect. Any market power assessment screen must be reviewed and evaluated in conjunction with actual market outcomes. Nevertheless, the need for such a screen is clear. The ISO urges the Commission to develop a clear and measurable standard for just and reasonable rates.

6. Provision of Data (PP 448-449)

As a condition for participating in the spot markets and using the transmission grid, the Commission proposes that market participants must agree to provide the MMU with any information requested. In particular, the Commission proposes that market monitors have the ability to obtain data on generator production and opportunity costs and information on the operating status of transmission and generation facilities.

The ISO fully supports the Commission's proposal to provide the MMU with any information it requests, including generator production and opportunity cost information Such information is critical to effectively evaluating market participant behavior. The ability of a MMU to perform its job effectively and evaluate market participant behavior is dependent on the ability to acquire necessary information. Accordingly, the MMU must have the ability to require market participants to provide necessary information

The ITP and/or the MMU also should have the authority to take action (*e.g.*, penalize) those market participants that do not comply with data requests. To ensure compliance with information requests, the ITP's tariff must specify penalties that would apply to market participants that fail to comply with information requests The ISO notes that the Commission previously has imposed requirements that market participants provide information requested by independent transmission providers and/or market monitoring units and penalties for non-compliance. *See, e.g.*, *Northern Maine Independent System Administrator,* Inc, 91 FERC ¶ 61,060 (2000)("*Northern Maine ISA*"), *California Power Exchange Corporation*, 88 FERC ¶ 61,112 (1999)("*CalPx*"), *New England Power Pool*, 85 FERC ¶ 61,379 (1998)("*Nepool*"). Consistent with prior decisions, the Commission, in its final rule, should: (1) require market participants to provide the MMU with requested information as a precondition to participating in the ITP's markets or using the transmission grid, and (2) approve penalties that would apply in the event of non-compliance with this requirement

The ISO notes that, in the near future, it will be filing with the Commission an Oversight and Investigation proposal that, *inter alia*, would require market participants to comply with ISO information requests and provide factually accurate information. The ISO would impose penalties on market participants that fail to comply with these rules. The Commission should approve this aspect of the ISO's filing which is not only consistent with SMD and the authority the Commission has given other independent transmission providers, but is a necessary component of any proper functioning market.

7. Annual Reports (P 453)

The Commission states that, at a minimum, the monitor would be required to submit an annual report to the Commission and the ITP's governing board, and share that report with the Regional State Advisory Committee. The report would include: (1) a general description of the market operations, supply and demand, and market prices; (2) an analysis of market structure and participant behavior following specified guidelines described above; (3) an evaluation of the effectiveness of mitigation measures taken; (4) an overall assessment of market efficiency perhaps using a simulated competitive benchmark as some have developed; (5) an evaluation of barriers to entry for generating, demand-side, and transmission resources; and (6) any recommended changes to market design or market power mitigation measures to improve market performance. The report would also include a discussion and analysis of any region-specific issues that the monitor judges important to achieving a competitive outcome. In addition, the MMU will be required to report to the Commission, through the Office of Market Oversight and Investigation, any instances of conduct by market participants that appear to be inconsistent with the ITP's tariff. The Commission requests comment whether additional reporting requirements are needed

The ISO proposes that the reporting obligation be that of the ITP and not the MMU directly. In other words, the ITP would be required to submit an annual report of market performance and suggested changes. Otherwise, the latter part of the obligation implicates the ITP's Section 205 filing rights.

8. Mitigation of Penalties (P 456)

The Commission states that it may be appropriate to build into the tariff standards for mitigating penalties. Some standards that could be used include: the impact on the operation of the grid, the financial impact on the violator, and any good faith efforts to maintain compliance. The Commission requests comment on the conditions that would justify mitigation of the penalty.

In the NOPR, the Commission proposes to require the ITP to include, at a minimum, the following behavioral rules addressing: (1) physical withholding, (2) economic withholding, (3) availability pricing, (4) factual accuracy, (5) information obligation, (6) cooperation, and (7) physical feasibility. These rules would be accompanied by predetermined penalties

The ISO supports the Commission's proposal to implement a set of minimum behavioral rules and corresponding predetermined penalties that would apply to conduct that violates such rules. Recent gaming practices and strategies should be more difficult with such behavioral rules (and corresponding penalties) in place and with the advent of LMP. That is one of the reasons why the ISO has undertaken an ambitious market redesign under MD02 and will be proposing new behavioral rules as part of its Oversight and Investigation program However, more than just changes in market design are needed to address gaming, market manipulation and other types of inappropriate behavior employed by market participants ITPs need effective enforcement mechanisms to prevent these types of activities and to react to such activities swiftly In particular, ITPs need tools to ensure that market participants (1) do not engage in physical or economic withholding, (2) comply with ITP/MMU information requests and provide factually accurate information, (3) submit feasible schedules, and (4) do not engage in gaming or market manipulation that jeopardizes reliable operation of the transmission grid and/or efficient operation of markets.

The behavioral rules proposed by the Commission are comparable to those specified in NEPOOL's Market Rule 13. Further, these rules are consistent with similar market rules that the Commission has approved for the New York ISO, the Northern Maine Independent System Administrator and the California PX. The proposed rules should be a basic requirement in any independently operated market. Such rules address activities that can jeopardize the reliability, competitiveness and efficiency of the markets and reliable operation of the transmission grid and can hinder investigations by the ITP and the MMU. As such, including these market rules in the ITP's tariff is both appropriate and necessary.

The ISO notes that its Oversight and Investigation proposal will establish clear market rules (and corresponding sanctions) that are similar to the market rules proposed in the NOPR. In addition, the Oversight and Investigation proposal will establish transparent procedures for the ISO to (1) monitor the market to detect violations of such market rules, (2) investigate potential violations of such market rules, and (3) impose sanctions on market participants that violate the rules. The Commission should approve these aspects of the ISO's Oversight and Investigation proposal which are consistent with the policy enunciated by the Commission in the NOPR and the Commission's decisions in prior proceedings

The Commission requests comment regarding the standards that could be applied in determining whether a penalty should be mitigated. The ISO submits that the following criteria should be considered in determining the level of any penalty: (1) the degree to which the market participant benefited from the activity; (2) whether the conduct occurred during a system emergency or alert; (3) the degree to which the conduct may have affected system reliability or market integrity, (4) the degree to which the conduct affected overall market prices; (5) whether other entities were harmed as a result of the behavior and the extent of the harm; (6) whether the conduct was willful, intentional or grossly negligent and whether there were other mitigating or aggravating factors; (7) the frequency of the conduct, (8) the duration of the conduct, (9) whether the market participant was acting alone or in concert with others; (10) the market participant's attempt to cure the misconduct or provide restitution, (11) the market participant's history of prior misconduct; (12) the appropriateness of the penalty to the magnitude of the market participant's business, (13) the deterrent effect the penalty is likely to have on similar conduct by other market participants; (14) whether the conduct results from a *force majeure* event; (15) good faith efforts on the part of the market participant to maintain compliance; and (16) whether the market participant's misconduct resulted from its attempt to comply with licensing, environmental or other regulations or laws. This constitutes a comprehensive list that will ensure that all material mitigating factors are considered in determining the level of any penalty. The Commission previously has approved tariff provisions specifying many of these criteria. *See Nepool, supra; CalPx, supra; Northern Maine ISA, supra.*

X. Long Term Resource Adequacy (PP 457-550)

A. Summary of ISO's Position

The ISO agrees with the Commission that ensuring long-term resource adequacy must be a fundamental objective of any market design. A long-term resource adequacy framework is necessary to support investment in electric supply resources (both generation and demand) and, in the end, reliable system operation. While ITPs and the Commission may play an important backstop role with respect to resource adequacy, the ISO believes that LSEs and the agencies that regulate them at the local level must play a primary role in ensuring long-term resource adequacy. Moreover, any long-term resource adequacy requirement ultimately established by the Commission must, by necessity, complement and be coordinated with measures established at the local level. Conflicting standards will only create confusion and increase costs in the markets and, ultimately, to consumers.

Thus, the ISO urges the Commission to defer to state and local authorities to develop a sound framework for ensuring resource adequacy. Alternatively, the Commission should establish only those standards that are necessary to support an ITP's core functions – that of providing open and non-discriminatory transmission service and reliable grid operation. In California, a collective effort is under way to reestablish such a framework, and the ISO supports further development of the State's efforts before the Commission defines what may be required with respect to an appropriate resource adequacy requirement for users of the ISO Controlled Grid.

As a general matter, the ISO believes those minimum requirements should include provisions for the complete and timely sharing of information with respect to the resources of all LSEs served by an ITP's system. Advance provision and sharing of information is critical if the

ITP is to operate the transmission system reliably in real-time. Absent advance notification, an ITP may be forced to scramble at the last moment to find power to serve load or may be forced to shed load.

In addition, notwithstanding the existence of local requirements for a LSE to be resource adequate, it may be appropriate for an ITP to establish penalties or energy-adders for entities that rely on spot market purchases to fulfill their capacity requirements.[35] Moreover, as expressed previously herein, the ISO believes that it may be appropriate to establish a graduated system of penalties or energy-adders based on the system conditions that exist. For example, an ITP may want to establish a separate adder applicable to real-time energy purchased under normal system conditions and a different, higher adder that would apply to purchases through the spot market when a reserve deficiency exists. Such an approach would establish more explicit incentives for LSEs not to rely on spot market purchases, especially under tenuous systems conditions.

As a general matter, the opinions expressed below by the ISO with respect to certain aspects of resource adequacy are intended to provide broad guidance to both state and federal policymakers. Moreover, the comments expressed herein are consistent with the comments previously submitted to the Commission by the ISO. *See* the ISO's Statement of Position, filed on December 2, 2002, in Docket No ER02-1656-000, pp.67-90, and Attachment A thereto. As such, the ISO's comments are influenced by not only the ISO's experience over the past four years, but also the development of its own resource adequacy proposal (*i.e.,* ACAP) and the subsequent discussions with the State and market participants that have occurred during the meetings of the MD02 Resource Adequacy Working Group ("RWG"). .

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[35] The ISO distinguishes between energy trading, *i e* , purchasing less expensive energy from the spot market rather than producing more expensive energy from an existing capacity resource, from procuring sufficient *capacity* in the forward markets Any resource adequacy proposal should focus on the requirement to procure adequate *capacity* in the forward market and should not limit a load-serving entity's ability to self-manage those capacity resources and trade energy

B. Capacity Requirement (P 474)

The Commission proposes to require that the ITP forecast the future demand for its area, facilitate determination of an adequate level of future regional resources by a Regional State Advisory Committee and assign each LSE in its area a share of the future resources based on the ratio of its load to the regional load

In its May 1 MD02 Filing, the ISO proposed to establish a system-wide reserve requirement or obligation and then determine each LSE's share of that obligation by examining and allocating responsibility to each LSE based on the LSE's historical contribution to the peak load of the system. This approach is similar to the approach outlined in the NOPR At that time, the ISO believed that, while not precise, such an approach was fair and would reduce or eliminate incentives for LSEs to manipulate their load forecasts to reduce their reserve obligation.

A number of parties, including LSEs and the California State agencies objected to that approach, arguing that it gave the ISO too much discretion and could result in the ISO imposing unreasonable costs on LSEs by imposing a reserve requirement based on an inaccurate historical load profile. In the context of the MD02 Resource Adequacy Working Group discussions, the Resource Adequacy Working Group acknowledged that if capacity obligations are not imposed three years out, load forecasts can be done by the LSEs, with the ISO "using" such forecasts as it sees fit If obligations are imposed, most parties believe that non-coincident peak forecasts by LSEs should be used in setting obligations, although, it was acknowledged that the ISO is in the best position to conduct a system-wide forecast to be used to determine system-wide capacity needs. However, forecasting-related issues were not considered to be a primary issue.

At this point in time, the ISO believes that ITPs should generally defer to state/regional authorities to determine the appropriate level of reserves to be procured by LSEs. Moreover, the ISO advocates a collaborative effort among regional authorities, LSEs and the ITP to develop the aggregate system-wide load forecasts necessary to derive the obligation

C. Curtailment (P 477)

The Commission states that, to the extent possible, the ITP must curtail the spot energy purchases of the load-serving entity that did not meet its resource adequacy requirement before curtailing the spot energy purchases of entities that did.

The ISO supports the inclusion of incentive mechanisms, including priority curtailment of load, in any established resource adequacy proposal or mechanism. In particular, with respect to California, it is of utmost importance that the State (specifically the California Public Utilities Commission) establishes clear rules and consequences for the investor owned utilities ("IOUs") with respect to forward-market procurement activities Specifically, the ISO supports the adoption by the CPUC of explicit penalties/sanctions for IOUs that fail to follow CPUC-established procurement guidelines. Such penalties should be established at a level necessary to provide sufficient incentives for the IOUs to comply with the set rules and should be tied to the cost of building new resources.

With respect to any ITP-oriented resource adequacy requirement ultimately deemed to be necessary, the ISO also believes that it is imperative that the Commission establishes clear rules and consequences for non-compliance. Absent the creation of an incentive-compatible resource adequacy mechanism, LSEs will fail to comply and the ISO (or any ITP) may be forced to satisfy large amounts of load through the spot market – an outcome that will inevitably lead to higher prices.

The ISO's May 1 MD02 Filing provided that LSEs that fail to procure sufficient capacity on a month-ahead and day-ahead basis would be subject to either financial penalties or priority curtailment before the ISO entered into a reserve deficiency period. The ISO reasoned that such penalties/curtailments were necessary to ensure that load-serving entities had proper incentive to procure capacity in the forward market. The ISO continues to believe that proper incentives are necessary to motivate compliance with a resource adequacy requirement and notes that all of the eastern independent system operators assess comparable penalties for non-compliance with their established capacity requirements Absent such penalties, the ISO is convinced, based on past experience, that LSEs will assume the risk that necessary power will be available in the spot market, especially if such spot markets are subject to strict price mitigation measures.

The ISO's MD02 Resource Adequacy Working Group has also discussed this issue. At this juncture, there appears to be uniform agreement that, at a minimum, it is appropriate for the ISO to assess a surcharge for real-time energy purchased during a Stage 1, 2 or 3 Emergency In other words, the ISO should impose graduated penalties on LSEs that are determined to be capacity short in the Day-Ahead, for imbalance energy based on system conditions For example, if the ISO were to go into a Stage 1 Emergency (operating reserves fall below seven percent), the ISO should charge a $100/MWh surcharge on energy purchased by capacity-short load-serving entities from the ISO's real-time market In a Stage 2 Emergency, a $250/MWh surcharge would be assessed and in a Stage 3, a $1000/MWh surcharge. The ISO believes that such an approach is similar to that proposed in the NOPR.

To date, the ISO is not aware of any party that supports penalties applied on a month-ahead or further-out basis. As articulated by certain participants in the RAWG process, such penalties necessarily and adversely impact LSE procurement practices and discretion – matters these entities believe are best addressed or overseen by local regulatory authorities. The ISO acknowledges these concerns and, as stated above, supports development of such penalties coincident with the development of procurement rules by local regulatory authorities.

Therefore, if an ITP-established resource adequacy mechanism is deemed necessary, the ISO is prepared to support an alternative approach. However, the ISO proposes that, instead of assessing penalties based on a forward-market assessment of resource adequacy, the ITP should instead establish a forward-market priority curtailment list, to be utilized in real-time if necessary. The priority curtailment list would be based on information required to be submitted by LSEs on a periodic basis – perhaps monthly. Such priority curtailment list could possibly be made public and published on the ISO website. Thus, LSEs could effectively "buy down" their curtailment priority by procuring more capacity On a real-time basis, prior to the ISO going into a Stage 3 Emergency, the ISO would curtail the firm load of LSEs based on the priority curtailment list. LSEs that did not follow the ISO's curtailment instructions, based on an *ex post facto* review of meter data would be penalized. In addition, similar to the proposal outlined above, all load-serving entities that were capacity short in the Day-Ahead market that choose to rely on the ISO's real-time energy market during a Stage 1, 2 or 3 Emergency would be assessed a surcharge on such energy. The ISO believes that such an approach would establish the appropriate incentives for LSEs to procure sufficient capacity in the forward market

Finally, the ISO, consistent with its previous statements to the Commission (*See* Attachment A to the May 1 Filing, p. 67 of 166) cautions the Commission as to the practical capability of curtailing a specific LSE's load absent the priority curtailment list, the after-the-fact review procedures discussed above, as well as the technical capability.

D. Coordination (P 488)

The Commission states that close coordination is needed between those planning generation and transmission because the location of planned generation affects the location of planned transmission and vice-versa

The ISO agrees that there are clear benefits to integrated system planning, benefits that may not be captured in an unbundled and competitive market environment. Historically, vertically integrated utilities were able to balance and trade off both generation and transmission investment. Those opportunities are not as readily apparent or available in an ITP and merchant generation-dominated environment. However, as recognized by the Commission, coordinated regional planning does provide certain opportunities to conduct integrated planning

Nonetheless, as indicated above, concerns arise as to how one can objectively compare among and between wires (*i.e.*, transmission) and non-wires solutions to identified needs. In addition, reliance on merchant generation poses certain difficulties both from a planning and a pricing perspective.

E. Planning Targets in Energy Limited Areas (P 489)

The Commission states that there should be a regional determination as to what the appropriate level of resource reserves should be. The Commission seeks comment on the appropriate planning targets in energy-limited areas and, specifically, on how to incorporate volatility of annual hydropower supply.

The issues raised by the Commission with respect to resource reserves in energy-limited areas reinforces the need for the Commission to defer to regional authorities to determine reserve levels. As the Commission appears to recognize, the individual physical characteristics of each region's resources must be accounted for and incorporated into the development of any regional planning requirement and reserve level determination. Thus, for hydropower-dominant regions such as the West, the hydrological cycle, as well as water-use and environmental restrictions, must all be factored into a reserve level planning and determination process. In California, while hydropower issues are large and very pertinent, the use of other energy-limited resources is also a critical issue.

Just as the use of and planning for hydropower resources is important to the Pacific Northwest, the use of and planning for environmental or use-limited resources is equally important to California. As of today, California has multiple "air-quality districts " The boards that manage these districts are responsible for ensuring that each of these districts complies with both federal, state and local air quality standards. Paramount to that effort is the control of the electric generating resources that are the primary contributors to air-born pollution within the districts. To that end, each of the air-quality districts has adopted strict use-restrictions for those resources, thereby limiting the amount of power each resource can produce during a given period. These restrictions are most often applied on a calendar-year basis. As a consequence, the ISO and the resource owners must plan for the use of these facilities with such restrictions in mind.

As it pertains to ISO operations and the ISO's need for a resource-adequacy requirement, the operation of use-limited resources is particularly important Since inception, the ISO has had in place certain Reliability Must-Run or "RMR" contracts with certain generators. These contracts are needed so that the ISO can maintain system reliability by dispatching generators for needed voltage support and to satisfy other locational requirements. As a consequence, the ISO entered into cost-based RMR Contracts with these resources. On an annual basis, the ISO reviews and assesses its locational requirements and resource needs within each of the so-called RMR Areas within the ISO's Control Area.

Obviously, this assessment not only factors in how much these local resources can be dispatched (MWh) on an annual basis, it also assesses the locational transmission constraints that give rise to the ISO's locational requirements Thus, while simultaneously exploring what resources can satisfy its locational requirements, the ISO and PTOs also explore transmission enhancements that could reduce or eliminate the locational requirements. If such transmission additions are deemed feasible and cost-effective, the ISO then incorporates these transmission additions into its annual integrated transmission plan. Thus, transmission planning and transmission constraints factor heavily into the ISO's annual locational resource assessment and have a significant impact on any resource adequacy assessment. In fact, it was in recognition of these locational constraints that the ISO proposed a "locational" ACAP obligation in its May 1 MD02 Filing. In part because of the "deliverability" issues related to resource adequacy, but also because of the unique and critical role that local use-limited resources play in satisfying and serving load in California, the ISO believes that any resource adequacy mechanism must acknowledge and account for the use of energy or use-limited resources and the local transmission constraints that necessitate their use.

In the future, it is essential that the ISO be able to work with resource owners and local authorities (especially the air quality districts) to establish resource and planning requirements that accurately account for the use of such use-limited resources. The ISO does not believe that it is appropriate or feasible for the Commission to establish any kind of generic standard that would accurately reflect these local requirements. Therefore, the ISO requests that the Commission defer establishing any generic or standard requirements regarding the treatment of use-limited resources.

F. Default Reserve Margin (P 492)

The Commission seeks comments on what the fallback provision should be employed if the Regional State Advisory Committee does not reach agreement on the appropriate level of resource adequacy. The Commission believes that having different reserve levels in different states in the same region maintains the problem of some customers relying on the reserves of others.

As stated previously, the ISO recommends that the Commission defer to ITP-regional or, if appropriate, supra-regional authorities to establish appropriate level of planning reserve In the first instance, the level of planning reserves should be established by authorities within each ITP's region. By deferring to such "local" authorities, the development of resource adequacy requirements can be coordinated between the ITP and local authorities These authorities must establish standards that, not only address general policies that impact resource adequacy and reliability, but also address other public policy-related issues, such as fuel-diversity, renewable resources, land-use and other environmental issues. Moreover, because local LSEs will be the primary entities responsible for implementing resource-adequacy-related policies (*i.e.*, they will be the primary "portfolio managers" under any resource procurement mechanism), it is appropriate to allow for a coordinated effort among and between the LSEs , local regulatory authorities and the ITP to develop reserve level standards.

To the extent that local authorities fail to establish reserve levels or establish disparate reserve levels such that either ITP operations are compromised or "free riding" is encouraged, the ISO supports the concept of a supra-regional authority establishing a generic reserve level requirement for the region. The ISO believes such an entity could be the Regional State Advisory Committee proposed by the Commission or it could be another regional authority In the West, for example, as they do today, entities such as the Northwest Power Planning Council or the Southwest Power Pool could step forward and establish reserve level standards Moreover, the WECC could also re-establish (and enforce) the planning standards previously in place for the Western region.

With respect to the appropriate level of such reserves, the general guideline historically followed in the industry is that an adequate planning reserve is one that would limit reliability risk to one-day-in-ten-years loss of load probability, *i.e.*, the WECC's previously established planning reserve requirement. In the May 1 MD02 Filing, the ISO proposed that LSEs maintain a capacity reserve level of 10% to 12% based on "unforced capacity" in the forward (month-ahead) time frame and about 10% based on "available capacity" in the day-ahead time frame. This is comparable to the 12% minimum margin identified in the NOPR. In California, the California Power Authority recently adopted a 17% target reserve level, based on dependable capacity, for purposes of guiding its own financial plan.[36] Moreover, the CPUC previously acknowledged the CPA's rulemaking and stated that the CPUC would be guided by the CPA's determination when establishing rules and requirements for IOU procurement practices.[37]

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[36] See Final Decision D03-001 in CPA Rulemaking Establishment of Target Reserve Level for the California Power Authority Investment Plan, issued January 17, 2003 in Docket 2002-07-01.

[37] See CPUC Interim Opinion D.02-10-062 issued October 24, 2002. The interim opinion provisionally sets "the reserve level at 15%, subject to consideration of utility specific requirements and reexamination once the Power Authority proceeding comes to a final recommendation " D 02-10-062 at 29

In addition, and most importantly, the ISO notes that the level of resource adequacy (*i.e.*, the level of reserve as a percentage of peak load forecast) and the accounting rules for determining the resource capacity go hand in hand Accordingly, they must be addressed together. For example, a reserve level of 18% based on net dependable capacity may correspond to a reserve level of 12% based on "unforced capacity" (net dependable capacity discounted for historical forced outages), and a reserve level of 24% based on installed capacity. The ISO believes that disagreement regarding the level of resource adequacy may in fact result from the lack of a common reference regarding the accounting rules Therefore, it is important to agree on the accounting rules (*i.e* , how resources are counted) first before attempting to reach regional consensus on the reserve level of supply adequacy.

In conclusion, the ISO recommends that the Commission generally defer to state and regional authorities in setting the reserve standard. Only after such reserve levels are clearly defined, should the ISO or the Commission consider whether other *minimum* standards for users of the ISO system are necessary and what such standards (i.e., minimum reserve level) should be.

G. Allocating the Regional Resource Requirement (PP 497-502)

1. Determination of each LSE's Share (PP 497-500)

The Commission identifies two methods for determining each LSE's share of the regional resource requirement. One method is to allocate the future resource adequacy needs to loads based on each load's forecasted future demand The other method is to allocate the future adequacy requirement to loads based on each load's most recently documented load ratio share. The Commission asks for comments on which of these two methods the Commission should choose in the Final Rule. Alternatively, the Commission asks whether this issue should be left to regional determination.

As discussed above, the ISO recommends that the Commission defer to state/ITP-regional authorities, in consultation with the ITP, to determine the allocation methodology that best addresses each region's requirements. In general, the ISO supports the allocation of any established reserve requirement on the basis of a LSE's *historical* contribution to the system peak load. The ISO supports such an approach for the following three reasons: (1) use of historical contribution to the peak (*i.e.*, load ratio share) eliminates the need to rely on a LSE's forecast and therefore eliminates concerns about a LSE's incentive to game the forecast to reduce its future resource obligation; (2) use of peak load (and each entity's contribution thereto) necessarily reflects system diversity; and (3) use of historical contributions is simpler and does not require the validation of new load forecasts. Although such an approach may need to permit LSEs to demonstrate why their historic contribution to a ITP's system peak does not accurately represent going-forward usage or contribution.

2. Timing Issues (P 502)

The Commission states that the time available to the LSE after being informed of its resource share to report to the ITP must be adequate so that it can develop arrangements for meeting future resource needs The Commission asks for comments on how much time is needed for these purposes.

As stated in the ISO's December 2, 2002, Statement of Position in Docket No. ER02-1656, the ISO has long advocated the phase-in of a resource adequacy obligation. In the May 1 MD02 Filing, the ISO proposed that its ACAP proposal not be implemented until 2004. The ISO's primary reason for proposing a delayed implementation was to ensure that LSEs have a reasonable amount of time to procure the capacity necessary to satisfy the requirement. The ISO was, and remains, concerned that if LSEs are not provided adequate time to procure capacity, they will be subject to the exercise of market power by suppliers. Stated differently, knowing that LSEs must procure sufficient capacity to satisfy their obligations, suppliers will demand high prices for that capacity. Clearly, that would be a sub-optimal outcome.

The difficulty is determining how long implementation should be deferred. Ideally, LSEs should have sufficient time to exercise the "build" option. Specifically, there should be adequate time for an LSE, if faced with paying exorbitant prices for capacity from existing suppliers, to instead opt to construct its own capacity. However, it takes a minimum of approximately three years to build new generating capacity in California, and that may be too long to delay implementation of a resource adequacy requirement.

Alternatively, a LSE could develop sufficient demand-response to comply with a resource adequacy requirement. However, because demand programs generally are undertaken by LSEs and overseen by State authorities, it is unclear how long it may take to develop such programs. Thus, the matter of selecting a phase-in schedule for a resource adequacy requirement is more art than science and requires trade-offs among a number or variables. At this time, the ISO has requested a one year deferral in the consideration of its own proposed resource adequacy requirement to allow the State to address resource adequacy issues in the first instance.

Notwithstanding a delay in the implementation of a formal requirement, the ISO supports moving ahead and establishing the information and validation framework necessary to administer a requirement. As expressed earlier, be it a state, regional or federally-established requirement, ITPs must receive all information regarding resource adequacy in order to maintain system reliability and prepare for real-time operations Under such an approach, the ISO could begin to assess, on an information basis, whether LSEs that use the ISO Controlled Grid are or have procured sufficient capacity to satisfy their peak load requirements. To the extent the ISO/ITP believes they have not, the ISO/ITP can inform the appropriate parties (including all applicable regulatory agencies) and make the necessary arrangements (including, if possible, priority load curtailment) to maintain reliable system operation.

In conclusion, the ISO supports further development of State or local regulatory authority-established resource adequacy standards and, to the extent that they do not currently exist, a measured phase-in of such requirements to avoid subjecting load-serving entities to the potential exercise of market power.

H. Generation Under Contract (P 505)

The Commission states that the supply requirement can be satisfied by self-owned generation, local distributed generation or firm bilateral contracts for power backed by generating units. Generation under contract must specify that the generator will be available to the LSE – or at least to the market in which the LSE participates – under conditions set out in the contract

The ISO urges the Commission to remain flexible as to type of resources that would qualify to satisfy a resource adequacy requirement. Furthermore, the ISO urges the Commission to defer to state/regional authorities to make such determinations. As it is, each region typically develops products that conform and facilitate the nature and type of trading practices in place in that region. Therefore, each region is best suited to determine the type of resources that qualify as "firm" and thus satisfy a resource adequacy requirement.

In the May 1 MD02 Filing, the ISO proposed that all firm resources be eligible to provide ACAP. Specifically, the ISO proposed that all existing and new generation, including thermal, hydro, renewable, qualifying facility-type generation be eligible to provide resource adequacy-qualified capacity. In addition, the ISO stated that demand-based products, including load under IOU interruptible programs, should be eligible to provide ACAP. Finally, the ISO stated that existing firm energy contracts and contracts for imported firm energy also should be eligible to provide ACAP. The ISO continues to support these positions.

The NOPR provides that only identifiable physical resources should be able to provide capacity to satisfy a resource adequacy requirement. The ISO agrees with this position, in part. While the ISO agrees that all qualified resource adequacy-capacity within a transmission provider's control area should be tied to a physical resource, the ISO also supports participation by out-of-control area resources that are not necessarily identified with a specific physical resource

Furthermore, the pertinent issue before the Commission is not only *what* resources should be eligible to satisfy a resource adequacy requirement – all firm resources should be eligible – but *how much* of a resource's capacity should qualify or count towards satisfying a resource adequacy requirement. The ISO does not believe that a 100 MW resource whose historical availability is only seventy percent should qualify to provide the same amount of capacity towards a resource adequacy requirement as a 100 MW resource whose historical availability is ninety percent. The difficult issue is, of course, determining a resource's historic availability. Should the amount of capacity eligible to satisfy a resource adequacy requirement be that which was available ninety-eight percent of the time last year or ninety percent of the time? Should hydroelectric facilities be evaluated based on historical energy output? Should their eligible capacity be adjusted based on expected hydrological conditions?

The challenge is to develop a policy or accounting methodology that does not improperly discount available capacity, thereby diminishing the value of the affected resource and potentially raising costs to LSEs (and consumers) that are required to purchase additional capacity. Moreover, policies designed to encourage the development and use of renewable resource can be undermined by accounting methodologies that fail to account the full "value" of such a resource. While such matters are typically addressed in state forums, the California state agencies have not yet developed standard policy on the issue of how to rate resources. Moreover, comparable standards may need to be established for all resources and for all LSEs that use the ISO Controlled Grid.

Notwithstanding the lack of current California-specific standards, the ISO believes it is premature for the Commission to make any determination on this issue (*i.e.*, develop generic standards) and recommends that the Commission first permit State and regional entities develop their own region-appropriate standards. The ISO does not support resolution of these issues at NAESB at this point in time. While it may be appropriate to develop national resource standards (building off the work and data collected by such institutions as the Electric Power research Institute) in parallel with the development of local and regional standards, the Commission should not mandate the development of national or universally applicable standards and require each region/ITP to adopt those standards.

I. Generation and Transmission Standards (PP 511-516)

1. Physical Feasibility (P 511)

The Commission states that the ITP must be satisfied that the generation is physically feasible, *i.e.*, the generating units are capable of generating the power planned and enough transmission is available to deliver the power from the generating station to the particular load.

The issues raised by the Commission pertain to the availability of generation or other resources used to satisfy a resource adequacy requirement and the "deliverability" of energy from a resource to the designated load (*i e.*, can the energy be delivered over the existing transmission system). With respect to the resource availability issue, the ISO discussed that issue above The ISO provides its comments on the "deliverability" issue *infra* in subsection 4

2. Generation Under Development (P 512)

Because the purpose of the resource requirement is to encourage the development of new resources, the Commission states that generation under contract for development within the planning horizon should satisfy the resource requirement. The Commission asks whether it should specify the contract content needed to rely on generation under development? If so, then the Commission asks whether it should refer the matter to NAESB to determine the content.

As a general matter, the ISO does not believe it appropriate or necessary to specify the content – especially the commercial terms - of any contracts entered into between a supplier and a LSE to satisfy a resource adequacy requirement. Such requirements or content will by necessity change from ITP-region to ITP-region as permitting/siting, resource adequacy, and other requirements (including state laws) vary. However, the ISO recommends that certain minimum requirements be included in any such contracts.

As California and the Commission is aware, generation under development can easily disappear as the financial and credit status of both suppliers and LSEs change. Therefore, relying on generation under construction is very problematic. However, recognizing that new generation (as well as load-based resources) could very well constitute a large part of any LSE's resource portfolio, the ISO supports establishing terms and conditions of service that facilitates inclusion of new generation as a means to satisfy any resource adequacy requirement.

Specifically, the ISO recommends that the Commission and other appropriate regulatory bodies establish requirements to ensure that, at a minimum, *information* regarding the progress of new generation projects is shared on a timely basis with the ITP, the applicable LSE and the regulatory bodies that oversee the LSE's procurement practices. By sharing such information, the ITP and regulatory authorities can be assured that an "early warning system" is in place -- a system that enables the affected parties to take action (including the procurement of alternative resources) should contracted for resources not be available to serve load on a timely basis. Under this requirement, information reporting requirements and their timing could be tied to the identified development milestones that are typically part of a developer's construction and interconnection process (*e g* , land acquisition, state and local siting permits, acquisition of water and fuel rights, etc.) While there will always be an inherent risk in relying on market generation under development to satisfy a resource adequacy requirement, these risks can be in part mitigated by the timely sharing of information between developers, load-serving entities, regulators and ITPs.

3. Liquidated Damages (P 513)

In the NOPR, the Commission proposes that a contract with a marketer to deliver power at a future time from unspecified sources cannot satisfy the resource requirement. However, the Commission asks for comment on whether it should allow a liquidated damages contract for power from unspecified sources to be included in the resource adequacy plan. In addition, the

Commission asks whether it should allow a LSE that initially fails to satisfy the resource adequacy contract, but later brings in new resources under a liquidated damages contract for the amount of its resource deficiency, to avoid the penalty price and first curtailment in the spot market during a shortage.

In general, the ISO agrees that LSEs should be able to identify the physical resources designated to satisfy a resource adequacy requirement. In particular, the ISO supports such a requirement for resources located within an ITP's control area However, as noted earlier, the ISO supports the inclusion of out-of-control area resources among the mix of resources able to satisfy a resource adequacy requirement, and the ISO does not believe that such resources need to be tied to a specific physical resource.

Thus, the ISO is uncomfortable relying on a liquidated damages provision to satisfy a resource adequacy requirement. In general, contracts with liquidated damages provisions are acceptable. However, because a long-term resource adequacy requirement is intended to ensure that enough actual, deliverable generating capacity is available, the ISO is concerned that reliance on liquidated damages provisions may undermine that objective and will certainly reduce the ability of the ITP and/or others to monitor and assess resource adequacy (*i.e.*, reduce transparency).[38] At an absolute minimum, if the Commission permits the use of liquidated damages provisions in resource adequacy-related contracts, the Commission should establish a requirement that a LSE identify the specific capacity resources (except in the case of system resources, e.g., firm imports) to the ITP no later than the ITP's day-ahead market, but preferably much further out in time.

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[38] In contrast, liquidated damage provisions are intended to deal with the financial responsibilities of a supplier and the foreseeable, measurable, and reasonable amount of damage that may result should that supplier's resource become unavailable

4. Congestion Cost Payment Guarantees (P 514)

Generation must be deliverable in order to satisfy the resource requirement. The Commission asks whether a commitment by any LSE to pay congestion costs no matter how high also should satisfy the requirement. If so, the Commission queries how the ITP should respond if the sum total of all such commitments exceeds the available capacity of a bottleneck interface.

As previously explained, the ISO proposed to establish a locational ACAP (resource adequacy) proposal in its May 1 MD02 Filing Under the ISO's proposal, LSEs with load located in a transmission-constrained area would need to have under contract a specified amount of their capacity requirement within such transmission constrained area. Thus, under such a proposal, by defining "locational" resource adequacy requirements, the ISO would remove the need to determine whether resource adequacy resources were "deliverable."

The ISO continues to believe such an approach is viable. However, as noted above, before making any determination regarding the need for and details of a ISO/ITP-established resource-adequacy requirement, the ISO recommends that the Commission defer any action until State/local efforts on resource adequacy are finalized

With respect to the specific issue raised by the Commission, the ISO does not recommend that the Commission rely on either the procurement of CRRs by, or the "price-taker" status of, a LSE under an ITPs's congestion management protocols as assurance that such LSE's resources are "deliverable". In the first instance, CRRs are primarily (if not exclusively) a financial instrument and, thus, do not ensure scheduling or curtailment priority for their holder. Second, while the aggregate amount of CRRs to be issued is in part determined by conducting a "simultaneous feasibility test", such a test in no way guarantees that, on any given day, sufficient transmission capacity will exist to deliver all energy scheduled by CRR holders.

Similarly, even if a LSE elects to become a "price taker" for congestion (*i.e.*, the LSE agrees to pay whatever price is necessary to not have their preferred schedule reduced), the

ISO does not believe that such status is sufficient to ensure the deliverability of a LSE's scheduled resource. While "price-taker" status increases the likelihood that such LSE's schedule will be accepted, it does not guarantee that on any given day such entity's scheduled resources will be deliverable. The ISO believes that, by establishing a locational resource adequacy requirement, regulatory authorities can maximize the deliverability of resources necessary to serve load.

J. Planning Horizon (PP 524-525)

1. Lack of Consensus (P 524)

The Commission proposes to have the Regional State Advisory Committee determine the planning horizon for the region. The Commission requests comment on how to resolve any lack of consensus within the Committee regarding the appropriate planning horizon. The Commission also asks for comments on whether the Commission should establish limits on the region's choice of planning horizon, such as at least three years and no more than five years.

The ISO believes that determination of a longer-term planning horizon is necessarily an issue that needs to be addressed by local and regional authorities. In its May 1 MD02 Filing the ISO took notice of the ten-year horizon that is the basis of the Western Electricity Coordinating Council's Annual Loads and Resources assessment. The ISO intends to support, before local and regional authorities, the establishment of a resource adequacy planning horizon that is compatible with the development timeframes for generation and transmission (*i.e.*, three to five years). In addition, the ISO believes that it may be appropriate to establish longer-term reporting requirements that assess resource adequacy as far out as ten to fifteen years out in the future. Such studies and evaluations are appropriate from a strategic planning perspective and will necessarily bring to light important trade-offs not only between generation, transmission and load, but also within resource categories. For example, a longer-term vision would enable policymakers to examine whether investment in one 500 kV transmission facility is more appropriate than investment in two 230 kV or local demand/generation resources. In essence, a long-term (*i.e.*, 10 –15 year) planning horizon forces policymakers to fashion a vision of future and to structure a regulatory framework that comports with and supports that vision.

2. First Planning Horizon (P 525)

The Commission asks for comments on whether it should require a resource adequacy requirement before the end of the first planning horizon period. For example, if the horizon is three years, should there be a requirement for resource adequacy in the first two years?

As expressed earlier in Section G. 2., the ISO believes that a measured approach to implementing a resource adequacy mechanism is appropriate. Most importantly, the ISO believes that the implementation timing of any requirement should preserve a LSE's ability to exercise the "build" option and thereby reduce their exposure to the exercise of market power. The ISO submits that the effective date of any resource adequacy requirement must in part be tied to project development timelines particular to each region. In California, that may necessitate a 2-3 year implementation timeframe.

K. Enforcement (PP 526-541)

1. Introduction

The Commission identifies a number of alternative mechanisms for enforcing the resource adequacy requirement. The Commission seeks comments on the most effective enforcement method.

One alternative proposed by the Commission is for the ITP to add a per-megawatt-hour penalty price to the price of energy taken from the spot market during a shortage by a LSE that did not meet its share of the regional needs for the year. The Commission states that it would set the penalty price high enough to make it clear that failing to meet a resource adequacy *requirement and paying a penalty rate is not an acceptable alternative to developing new* resources The Commission states that the penalty price would increase in stages as the shortage becomes more severe. For example, the penalty price could be $500 (in addition to the spot market energy price) when operating reserves are just below the minimum level, $600 when operating reserves are more than below one percent below the minimum level, $700 when operating reserves are more than two percent below the minimum level, and so on The Commission asks for comments on having such a graduated penalty and the appropriate penalty rates.

The second enforcement mechanism would be applied when operating reserve levels decrease to the point where some load must be curtailed. Under these circumstances, the spot energy purchases of the deficient LSE would be reduced by the amount of its resource deficiency and, consequently, some of the LSE's customers would be curtailed before the loads of other LSEs. The Commission proposes to charge the applicable Locational Marginal Price plus $1000/MWh for all unauthorized energy taken following an instruction to implement curtailment. The Commission seeks comment on whether the $1000/MWh penalty would be sufficient to deter unauthorized taking of energy and, if these penalties are paid, who should receive these revenues

Under the Commission's proposal, the penalty rate or load curtailment would occur at the end of the planning horizon, not the beginning. However, the Commission asks for comment on this approach compared to an alternative approach that may provide a more immediate and effective incentive for a LSE to take action to provide for future resources well in advance of facing a penalty or curtailment That alternative would be to impose a penalty on the LSE immediately if it fails to submit a satisfactory plan to meet its resource adequacy requirement for a latter period (*e g.*, impose a penalty in 2004 for failure to submit a satisfactory resource plan for 2007). The Commission notes that it did not propose this option as its first choice because it has some of the unfavorable features of some ICAP programs that focus more on avoiding immediate penalties than on motivating long term resource development. However, the Commission requests comments on the merits of this alternative approach.

The ISO provides general comments regarding the various enforcement options below.

2. General ISO Comments Regarding Penalty Levels, the Curtailment Option and Possible Variations (PP529-536)

The ISO supports the inclusion of incentive mechanisms in an established resource adequacy proposal or mechanism. In particular, it is of utmost importance that all appropriate regulatory authorities establish clear rules and consequences for the LSEs under their jurisdiction with regard to forward-market procurement activities. Specifically, the ISO supports the adoption of explicit penalties/sanctions for load-serving entities that fail to follow local regulatory authority-established procurement guidelines. Such penalties should be established at a level necessary to provide sufficient incentives for the load-serving entities to comply with the set rules and should be generally tied to the cost building new resources.

With respect to any ITP-oriented resource adequacy requirement ultimately deemed to be necessary (if any), the ISO also believes that the Commission should establish clear rules and consequences for non-compliance Absent the creation of an incentive-compatible resource adequacy mechanism, LSEs will fail to comply and the ISO or any ITP may be be forced to satisfy large amounts of load through the spot market – an outcome that will inevitably lead to higher prices

The ISO's May 1 MD02 Filing provided that LSEs that LSEs that failed to procure sufficient capacity on a month-ahead and day-ahead basis would be subject to either financial penalties or priority curtailment before the ISO entered into a reserve deficiency period. The ISO reasoned that such penalties/curtailments were necessary to ensure that LSEs had proper incentive to procure capacity in the forward market. The ISO continues to believe that proper incentives are necessary to motivate compliance with a resource adequacy requirement and notes that the eastern independent system operators and power pools all assess comparable penalties for non-compliance with their established capacity requirements. Absent such penalties, the ISO is convinced, based on past experience, that LSEs will take the risk that necessary power will be available in the spot market, especially if such spot markets are subject to price mitigation measures. As noted earlier, the ISO's MD02 RAWG has also discussed this issue and the ISO believes there is uniform agreement that, at a minimum, it is appropriate for the ISO to assess a surcharge for real-time energy purchased during a Stage 1, 2 or 3 Emergency.

The ISO intends to engage in the ongoing State discussions and proceedings to address this and other issues related to resource adequacy.

3. Auditing of Resource Plans (P 537)

As proposed by the Commission, the ITP will audit the resource plan of each LSE only at the beginning of the planning period. The Commission expresses a concern that an LSE may submit a satisfactory plan but fail to implement the plan fully. The Commission asks whether it should require the ITP to audit the plan each year and assess the progress of the LSE in implementing its plan. The Commission then asks whether, if the load-serving entity's progress is unsatisfactory, whether the ITP should then find that the plan fails to satisfy its resource adequacy requirement. The Commission also asks, if the LSE implements its plan but some of its resources fail to perform when needed during a shortage, whether such LSE should be subject to either of the enforcement mechanisms identified above.

As expressed Sections A and M.2, above, the ISO believes that if an ITP is to reliably operate the system, it must have knowledge of the resources each LSE plans to use to satisfy its anticipated load requirements. Thus, the ISO believes that ITPs should periodically receive information regarding each LSE's resource adequacy. At a minimum, such information should be provided to ITPs on an annual basis. If the ITP is concerned that a load-serving entity's plans or resources are inadequate, the ITP can then report such concerns to the appropriate local regulatory authorities.

4. Curtailment of LSEs (P 538)

Another feature of the Commission's proposal is that it would not affect electric service from the self-generation and bilateral contracts of a LSE that fails to meet its resource adequacy requirement (except that it would be subject to a penalty price during a shortage for balancing energy in the spot energy market). The Commission seeks comments on whether this proposal unduly weakens the incentive to develop regional resources and whether, in the alternative, the ITP should first curtail service to the load serving entities that failed to meet their share of the resource adequacy requirement, including transmission service from resources acquired outside the spot market, freeing up those resources for the use of those that planned adequately.

The ISO does not support selective curtailment of specific transmission schedules In particular, the ISO does not support an ITP curtailing the bilateral or self-scheduled resources of a LSE that is deemed to have failed a resource adequacy requirement. While the ISO supports the concept of selectively curtailing the *load* of a resource-deficient LSE, the ISO does not support requiring ITPs to curtail or reject *transmission schedules*.

First, from a practical perspective, such an approach would require each ITP to develop and apply schedule flagging and validation procedures that would complicate their systems and application software. Second, and perhaps more importantly, the Commission's proposal would unnecessarily deny a LSE's (and an ITP's) access to available resources. Although a particular LSE may be resource-inadequate on a aggregate basis, it makes no sense for an ITP to deny or reject transmission schedules associated with the resources a LSE has procured. Obviously, if a LSE has scheduled the delivery of some resources, then it is, at least in part, resource adequate. More importantly, the Commission would achieve the desired incentive to comply by selectively curtailing a resource-deficient LSE's load (while still using that entity's resources to satisfy that entity's partial load and the load of other entities).

5. ITP Procurement of LSEs' Deficiencies (P 539)

The Commission also indicates that a possible option is to require the ITP to procure resources on behalf of LSEs that fail to meet fully their requirement and charge them for the cost of the resources. Another alternative is for the Commission to require the ITP to either (1) calculate an expected capacity deficiency and purchase the call options necessary to meet the adequacy requirement on behalf of the LSEs, allocating costs *pro rata*, or (2) require load-serving entities to purchase at the price produced by an ITP run auction.

As a general matter, the ISO does not support an ITP-backstop role in procuring capacity resources for LSEs.[39] The core function of an ITP is the provision of non-discriminatory transmission service and reliable system operation, not to participate in market activity LSEs, as overseen by local regulatory authorities, have and should retain the primary responsibility to ensure that they have procured sufficient resources to satisfy their anticipated load, plus reserves.

As to the issue regarding whether an ITP should facilitate a central capacity auction on behalf of LSEs, the ISO believes that such auctions are appropriately and easily facilitated by third parties. While the ISO recognizes that certain of the existing Eastern independent system operators facilitate central capacity auctions, this function was at least in part born out of their previous structure as a central power pool operator. In California, as with most of the West, no central capacity markets previously existed and LSEs traditionally satisfied their capacity requirements through the West's robust and highly-coordinated bilateral market. Such a market still exists in the West, and the ISO sees no reason to create a redundant central capacity market on top of the existing bilateral market. The Commission should defer to regional/local authorities on this matter and should not require each ITP to operate/facilitate a central capacity market/auction or otherwise take a position in the forward capacity market.

6. ITP-Operated Resource Market (P 549)

The NOPR permits, but does not require, the ITP to operate a market for acquiring and trading adequate resources. The Commission asks whether it should require an ITP to create a

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[39] Of course, the ISO does support an ITP as the provider of last resort for Ancillary Services and imbalance energy These services help satisfy the core requirements of an ITP and are necessary to provide non-discriminatory transmission service and reliable system operation.

market to facilitate LSEs meeting their resource adequacy requirement efficiently. The ISO has addressed this issue *supra* Section IX.M.7.

XI. State Participation in RTO Operations (PP 551-555)

A. The RSAC (P 552)

The Commission is proposing a formal role for state representatives to participate on an ongoing basis in the decision-making process of ITPs. Specifically, the Commission envisions that an ITP operating the grid would have a Regional State Advisory Committee and states that, "The specifics of how this advisory committee would be formed and operate would be decided on a regional basis." The Commission states that an RSAC would seek regional solutions to such as issues as, but not limited to:

a. Resource Adequacy;

b. Transmission planning, expansion;

c. Rate design and revenue requirements;

d. Market power and market monitoring;

e. Demand response and load management;

f. Distributed generation and interconnection policies;

g. Energy efficiency and environmental issues;

h RTO management and budget review.

The ISO supports "active engagement by state policymakers in the ITP process In addition, the ISO agrees with the Commission that the structure and function of any RSAC-type entity be decided on an ITP-regional basis. The ISO believes that states have a legitimate, if not primary role, in certain of the functions identified above – resource adequacy, demand response, energy efficiency and environmental issues, etc.[40] In contrast, ITPs have a primary role in transmission planning and management Thus, the goal of any such RSAC-type structure should be to facilitate an information-sharing forum between states and ITPs that will continue to rely on the relative expertise of each entity with respect to the performance of the identified functions

The ISO believes that with respect to each of the identified areas, there exists today mechanisms through which such a dialogue can take place. Moreover, as a single-state ISO, the principal forum for dialogue between the ISO and the states will be through the ongoing interaction between the ISO and the California State Agencies. As expressed throughout this document, the ISO believes that state/local authorities have a primary role in fashioning resolutions to. resource adequacy; demand response and load management; distributed generation and interconnection policies; energy efficiency and environmental issues. In addition, the ISO believes that state/local authorities have an important (and as of yet largely untapped) role in market monitoring. The ISO intends to develop and support policies and programs that further and facilitate the State's efforts on these matters. With respect to issues regarding transmission planning, transmission rate design and RTO management and budget review, the ISO believes there exists today ample opportunities for the state/local authorities to comment on and further those efforts. To that end, the ISO currently facilitates open discussions and dialogue with respect to each of those functions and will continue to do so to facilitate the State's support of those ISO-oriented activities. Therefore, the ISO believes that it is appropriate

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[40] The ISO does not believe that a RSAC should be the only means by which a State can participate in ITP operations To the extent that "formalizing" the State's involvement in the ITP through formation of an RSAC is intended to preclude any other means of State involvement with the ITP, the ISO believes that such an approach is unduly limiting. For example, in California, the Board of Governors of the ISO is appointed by the Governor. The formation of an RSAC should not preclude the Governor from appointing the members of the ISO's Board of Governors.

to facilitate state/local interaction regarding these matters and to fashion a structure for ITP-state/local coordination that best fits each ITP's region.

Furthermore, in order to facilitate greater supra-regional coordination, the ISO recommends that the Commission rely on existing structures and forums to further those efforts. Specifically, the ISO notes that both CREPC and SSG-WI currently facilitate inter-regional discussions regarding many of the issues identified above. The ISO supports those efforts and asks that the Commission rely on those structures to promote and further greater inter-regional coordination.

B. Number of State Advisory Committees (P 553)

The Commission seeks comment on whether there should be a single Regional State Advisory Committee, or separate committees for siting and other issues The Commission also seeks comment on how the state representatives should be selected (*e.g.*, whether the governor should select them or some other process should be used).

As expressed above, the ISO recommends that the Commission defer to each region to determine the structure, function and representation on any RSAC-type entity Many ITP-region may already have in place forums to discuss the issues and matters raised by the Commission. While the ISO fully supports the Commission's objective of furthering state/local agency involvement in ITP-related or impacted matters and inter-regional coordination, the ISO does not believe the Commission should fashion a one-size-fits-all approach to such matters and should defer to regional representatives.

XII. Governance for Independent Transmission Providers (PP 556 574)

The Commission proposes to require that all ITPs satisfy specific governance requirements. The Commission proposes that the ITP's nominating committee would retain a national search firm to identify candidates for the governing board. The nominating committee would be composed of two representatives from each of the six specified stakeholder classes.

The nominating committee would elect the board from the list of candidates specified by the search firm The Commission should undertake a collaborative process with the affected States to determine the appropriate governance structure for each ITP Each region has its own distinct concerns, problems, infrastructure and history. The Commission's preliminary conclusion that ITPs must have a specified governance structure will thwart regionalism The Commission should collaborate with the States and permit each ITP to have a governance structure that the State(s) in which the ITP operates transmission facilities believe is appropriate in light of the specific circumstances in the region Where established governance structures are already in place for existing independent system operators, the Commission should allow such governance structures to continue

ITPs that operate in a single state, such as the ISO generally are incorporated under the corporations law of such state. Accordingly, the State of incorporation has an overwhelming interest in ensuring the proper governance of such corporation and the exclusive right to do so. Except as limited by Congress acting within its constitutional bounds, states have plenary jurisdiction over corporations that are created by state law and the governance of such corporations is a matter that is definitively entrusted to the states. *Cort v Ash*, 422 U S 66 (1975). For the reasons set forth in the ISO's Request for Rehearing and Motion for Stay filed on August 16, 2002 in Docket Nos. EL01-35, *et al.*, the ISO submits that the Commission does not have authority under the Federal Power Act – either explicitly or implicitly – to direct the specific corporate governance structure or board composition of an ITP. The ISO hereby incorporates by reference the arguments contained in its Request for Rehearing and Motion for Stay.

A. Qualifications of Board Members (P 563)

The Commission provides a list of the qualifications, at least one of which Board members should have. The ISO submits that the Commission should not – and cannot -- require that Board members satisfy specific expertise requirements. The proposed list of qualifications should only serve as guidelines as to the areas of expertise that board members ought to have. Any illustrative list also should include areas such as economics, management, operation of markets, human resources and engineering fields in addition to electrical engineering.

XIII. System Security (PP 575-579)

The Commission proposes to require all regulated public utilities to file self-certifications annually that they meet specified security standards. In the case of entities seeking transmission service that are not public utilities subject to the Commission's regulations, the entity would still be required to demonstrate that it has a basic security program in place in order to receive transmission services. The Commission states that this could be accomplished by supplying the transmission provider with an executed self-certification using the Commission's form. Alternatively, the ITP and the customer could develop some other arrangement for assuring that the customer has a basic security program in place. Finally, after SMD is in place, *the Commission will require any customer seeking to buy or sell through any ITP market to* demonstrate that it has a basic security program in place.

The ISO supports the effort to establish national security standards that would uniformly apply to all entities that have access to critical infrastructure. To the extent that the self-certification form proposed by FERC would be filled out and submitted to FERC by all entities the ISO agrees that the proposed form is adequate. The ISO does not support, however, ISO/ITP administration and oversight of these standards. As these are proposed to be FERC-established national standards, the ISO believes that affected entities should self-certify to the Commission Furthermore, the ISO is concerned that ITP-administration of the system security self-certification process may unnecessarily increase an ITP's liability in instances where entities are later found to be in non-compliance with the established standards

XIV. ITP Administrative Cost Recovery and Creditworthiness Requirements

The ISO supports the Commission's effort to develop consistent market designs and market rules across regions. To support that effort, the ISO encourages the Commission to also consider establishing a consistent set of rules that would apply to the recording and recovery of an ITP's operating and capital costs. In particular, the Commission should standardize creditworthiness requirements for all ITPs.

As the Commission is aware, since the inception of the ISO, issues regarding the proper level and method for recovering ISO costs have persisted. The ISO has been embroiled in almost continuous litigation over these matters. While the order of magnitude of these costs pales in comparison to the dollars exchanged through the energy and capacity markets (especially during 200-2001!), ITP development and operating costs are not insignificant. The ISO incurred high start-up and development costs compared to other independent system operators, in large part, due its rapid development schedule. Accordingly, it is likely that future ITPs will incur significant start-up and development costs. Thus, litigation regarding the level and allocation of these costs is likely. In order to increase ITP-accountability and transparency and hopefully reduce litigation, the ISO urges the Commission to define accounting and ratemaking standards for ITP costs and the recovery of those costs.

Historically, prior to the advent of restructuring, Commission-jurisdictional entities operated within a detailed cost-of-service and accounting framework that was developed over many years. Specifically, the Code of Federal Regulations details the specific accounting conventions, procedures and methodologies that apply to costs incurred and expensed by public utilities Moreover, the Commission has well-established precedent regarding the appropriate ratemaking treatment of such costs. Such a structure does not exist for a large portion of ITP-related costs, such as the cost of developing and operating the systems and applications necessary to support an ITP's scheduling, operating and market systems. Currently, of the numerous accounts established to track utility costs under the Uniform System of Accounts, only a very small subset apply to existing ISO operations This small subset provides very little insight into the specific nature of ITP costs and does not permit a useful comparison between ITPs.

The ISO is aware that during 2000 the Commission's RTO Task Force commenced an effort to review potential changes to the Uniform System of Accounts to address this issue, but such efforts appear to have been placed on hold The Commission's early effort resulted in a preliminary listing of ISO services and was likely intended to lead to the development of accounts that track costs related to those services. The ISO urges the Commission to continue this most worthwhile effort.

Progress on this effort would also facilitate resolution of a related, but more significant issue. To date, the Commission has established very little precedent with respect to the ISO/ITP rate design and cost-recovery issues Currently, the cost recovery structures or charges of the various ISOs in existence today share few similarities. Significant resources have been devoted at each ISO to develop cost recovery structures; structures or proposals that have been vetted in contentious proceedings before the Commission. While most of these proceedings were eventually settled, some are still pending resolution before the Commission. While there may be benefits to allowing each ITP and its market participants to develop a rate structure that meets their needs, the ISO believes that the Commission should move forward to establish a standard framework for recording and recovering ITP-administrative costs. Such an outcome would reduce litigation among all parties and greatly reduce the Commission's administrative burden going forward.

XV. CONCLUSION

Wherefore, for the foregoing reasons, the ISO respectfully requests that the Commission adopt the recommendations set forth in these Initial Comments.

Respectfully submitted,

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Filed: February 19, 2003

CERTIFICATE OF SERVICE

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

Dated at Folsom, CA, on this 19th day of February, 2003.

Anthony J. Ivancovich