1. 2002 Market Structure Changes

1.1 New Market Power Mitigation Rules

For most of 2002 (January 1 to October 31), the ISO continued to operate under market power mitigation provisions referred to as the "West-wide Mitigation", which was developed through a series of FERC orders beginning on April 26, 2001 and continuing with orders on May 25, June 19, and December 19, 2001.The West-wide Mitigation provisions were to sunset on September 30, 2002 and, as a consequence, in the spring of 2002, the ISO developed and filed with FERC an alternative market power mitigation plan to take effect on October 1, 2002. This plan, referred to as the "October 1, 2002 Design Elements", was partially approved by FERC in a July 17, 2002 Order. However, due to an insufficient time to develop and implement all of the market power mitigation components approved in this Order, the ISO was granted a one-month extension of the West-wide mitigation provisions. The ISO began operating under the market power mitigation provisions of the July 17, 2002 Order on October 30, 2002. This chapter describes the changes in market power mitigation provisions and market design elements that occurred in 2002.

1.1.1 Market Mitigation Rules under West-wide Mitigation (Jan-Oct 2002)

FERC issued an initial order to provide market mitigation for summer 2001 on April 26, 2001. This was followed by a second and third order on May 25 and June 19, 2001, respectively, that revised, clarified, and expanded upon the April 26, 2001 order. Then on December 19, 2001 FERC issued several orders addressing the ISO's compliance with the mitigation orders and responding to ISO and other parties' requests for clarification and rehearing. These orders and the ISO's implementation of their provisions collectively comprise the market mitigation framework that existed in California from January 1, 2002 through October 31, 2002. This framework provided a number of important provisions that helped to maintain stability and reasonable prices in the ISO's markets. The major provisions during this period in 2002 included:

1.1.1.1 Must-Offer Requirement

This provision requires all non-hydro generating units that participate in the ISO markets or use the ISO Controlled Grid to bid all available capacity into the ISO's real-time market in all hours (the "Must Offer Obligation"). For long-start-time units, this obligation extends into the day-ahead time frame to enable the ISO to issue start-up instructions (or deny shut-down requests) for units the ISO expects to need to dispatch the next day.

1.1.1.2 Damage Control Bid Cap

The bid price mitigation provisions of the June 19, 2001 Order provided different mitigation provisions depending on whether the CAISO was operating in an hour when reserves were below 7 percent (reserve deficiency hours) or not. The price mitigation elements also applied to all other spot market sales throughout the WECC. During reserve deficiency hours, the mitigation provisions called for the dispatch of thermal generation based on unit-specific cost-based proxy bids with the market clearing price being set by the highest cost-based bid dispatched. Cost-based bids were based on the incremental heat rates of units and a monthly gas price equal to the average bid week prices, as reported in the trade publication “Gas Daily”, of the following trading hubs: SoCal Gas, PG&E City Gate, and Malin. During non-reserve deficient hours, a “soft bid cap” applied in the real-time market that was based on 85 percent of the highest-cost in-state generator that ran during the most recent reserve deficiency period. Resources that submitted bids above the “soft bid cap” were required to provide cost justification and were not eligible to set the market-clearing price.

During hours when the ISO was in reserve deficiency, no spot market transactions throughout the WECC could exceed the ISO market-clearing price, absent cost-justification. During hours when the ISO was not deficient in reserves, the “soft-bid cap” used in the ISO real-time market applied to all spot market transactions throughout the WECC.

In a December 19, 2001 Order (Order Temporarily Modifying the West-wide Price Mitigation Methodology), FERC made several important modifications to the price mitigation provisions. Specifically, FERC temporarily suspended the price mitigation provisions during reserve deficient and non-deficient hours through April 30, 2002, and replaced them with a uniform approach for all hours regardless of reserve levels. The temporary winter price mitigation set a soft-bid cap for spot market transactions throughout the WECC, including the ISO real-time market, of $108/MWh[1]. It directed that this cap be updated when the average of the three monthly gas indices used to determine the cap increased by 10 percent or more.[2] Thus, from December 20, 2001 through May 31, 2002, the ISO used the $108/MWh soft-bid cap.

On May 1, 2002, the temporary mitigation ended and was replaced by the original mitigation of the June 19, 2001 Order. The ISO did not experience a reserve deficiency during the months of May and June. Therefore, the price ceiling of $91.87 derived from the last reserve deficiency period (May 31, 2001) remained in effect. However, on July 9, 2002, the ISO issued a market notice stating that its operating reserves had fallen below seven percent and that it had recalculated a new price limit of $57.14/MWh. Also, on July 10, 2002, the ISO experienced another reserve deficiency period and issued a market notice setting a new price limit of $55.26/MWh. These lower price limits were largely due to the fact that monthly gas prices had declined significantly since May 2001 when the original price limit of $91.87/MWh was determined. In response to these market notices, FERC issued an Order on July 11, 2002 establishing $91.87/MWh as a fixed soft-cap for the spot markets throughout the WECC, including the ISO’s real-time market. This cap would remain in effect until the

[1] This value was based on the highest cost unit dispatched during the CAISO’s last reserve deficiency hour, which occurred on May 31, 2001 based on a monthly gas price index of $6.641/Mmbtu and an incremental heat rate of approximately 15,360 Btu/MWh and $6/MWh for the O&M adder. This new limit superceded the previous limit of $91.87/MWh, which was based on 85 percent of the $108/MWh.

[2] Under this approach, the price limit could be increased and decreased if monthly gas prices changed by more than 10 percent but could never fall below $108/MWh (i.e., the $108/MWh represented a floor).

mitigation provisions of the July 19, 2001 Order expired on October 31, 2002. The Commission explained that a price limit below this limit could potentially cause severe supply disruptions. Table 1.1 presents a chronology of the FERC Orders.

Table 1.1. FERC Mitigation Orders

Period	FERC Order	Price Limit	Comments
Dec. 20, 2001-April 30, 2002	December 19, 2001 (Order Temporarily Modifying the West-wide Price Mitigation Methodology)	$108/MWh	Applies all hours to all spot market transactions throughout the WECC.
May 1-July 8	June 19, 2001 Order	$91.87	No reserve deficiency hours
July 9-11	June 19, 2001 Order	Approx. $55.26/MWh-$57.14/MWh	Reserve deficiencies caused a recalculation of the price limit.
July 12-Oct 31	July 11, 2002 Order	$91.87/MWh	Commission removed the reserved deficiency methodology and implemented a fixed soft-cap of $91.87/MWh

1.1.1.3 Price Taker Provision for Import Bids

FERC required that marketers (i.e., suppliers whose supply is not from a specific generating unit) bidding into the real-time market be paid at the MCP but not be able to set the MCP (the “Price Taker” requirement). Price taking imports were required to submit a $0/MWh bid.

1.1.2 Overview of November 1, 2002 Design Elements (Nov-Dec 2002)

In May 2001, the ISO requested that the West-wide Mitigation be continued beyond the September 2002 sunset date, arguing that the mitigation should not terminate arbitrarily but rather should be based on a finding that the western markets are workably competitive. In the event the Commission chose not to continue the West-wide mitigation, the ISO proposed an alternative comprehensive market power mitigation plan. This plan contained several elements to address physical and economic withholding at both system-wide and local levels. The May 1 filing addressed economic withholding through a damage control bid cap (DCBC) and automatic mitigation procedures (AMP), addressed physical withholding through the continuation of the Must-Offer requirement, and requested stringent measures to address local market power. These provisions, referred to as the "October 1, 2002 Design Elements", were partially approved by FERC in a July 17, 2002 Order. However, due to an insufficient time to develop and implement all of the market power mitigation components approved in this Order, the ISO was granted a one-month extension of West-wide Mitigation. The ISO began operating under the market power mitigation provisions of the July 17, 2002 Order on October 30, 2002. We summarize each provision, as it was filed on May 1, 2002 and as it was subsequently modified by FERC in its July 17, 2002 Order.

1.1.2.1 $250 Damage Control Bid Cap

The ISO proposed in its May 1 filing to address economic withholding through the application of a damage control bid cap (DCBC) and automatic mitigation procedure (AMP). The ISO proposed a bid cap of $108/MWh that could increase with the price of natural gas and also could be increased over time as additional elements of MD02 are phased in and capacity conditions improve.

In its July 17, 2002 Order, the Commission adopted the ISO Market Surveillance Committee's recommendation and established a bid cap of $250/MWh beginning on November 1, 2002. The Commission agreed that the price cap mitigation was needed to mitigate the potential for market power abuse but felt that a price cap below $250/MWh would create disincentives for out-of-state suppliers to bid into the California market and could potentially result in a significant amount of out of market (OOM) calls above the price cap.

The bid cap of $250/MWh would also apply to the forward energy markets once implemented by the ISO. The Commission further ruled that this price cap was effective for all sales in WECC spot markets to eliminate incentives for "megawatt laundering". In its Order on Rehearing and Compliance Filing on October 11, 2002, the Commission further clarified that market participants may continue to submit bids above the bid cap with the understanding that such bids cannot set the market clearing price and that bids above the cap would be subject to justification and refund.

1.1.2.2 AMP

The ISO's AMP proposal would apply to bids that substantially exceed historical levels and threaten to materially impact market clearing prices (MCP). The AMP would apply to both the forward energy market (once developed) and the real-time energy market beginning on October 1, 2002. The ISO proposed thresholds to trigger AMP when a given resource's bid is the lower of 100 percent or $50/MWh above historically accepted bid levels in the previous three months (conduct test) and would increase real-time MCP by the lower of 100 percent or $50/MWh (market impact test). This proposed measure would apply to all bids, including hydroelectric resources and imports, but would not apply during hours in which the ISO had a day-ahead demand forecast exceeding 40,000 MW, nor would the accepted bids during these hours count toward a resource's historical bid average (Reference Level) for mitigation purposes.

In its July 17, 2002 Order, the Commission approved the ISO AMP subject to several modifications. The Commission directed an additional price screen test to determine whether AMP should be applied and ordered more generous thresholds for the conduct and market impact tests as summarized in Table 1.2.

Table 1.2. Conduct and Market Impact Tests

Design Element	CAISO Proposal	Commission Ruling
Minimum Price Screen	None	$91.87/MWh for all zones
Conduct Threshold	The lower of 100% or $50 increase over reference price	The lower of 200% or $100 increase over reference price
Impact Threshold	The lower of 100% or $50 increase in MCP	The lower of 200% or $50 increase in MCP
Applicability	➢ Hydro and imports included ➢ No exemption for small portfolios ➢ No exemption for new generation ➢ No minimum price offer exemption ➢ Not applicable when load forecast exceeds 40,000 MW	In July 17, 2002 Order: ➢ Hydro and imports included ➢ Small portfolios exempt from AMP once full network model is in effect. ➢ No exemption for new generation. ➢ Price offers below $25/MWh exempt. ➢ Applicable in all hours even if forecasted load exceeds 40,000 MW October 11, 2002 Rehearing Order: ➢ Reverse the July17 order to exempt bids from outside California from AMP and require imports to submit zero bids into CAISO markets

In its July 17, 2002 Order, the Commission ruled that, consistent with the ISO proposal, hydroelectric resources and imports were also subject to AMP. However, its following Order on Rehearing and Compliance Filing on October 11, 2002, the Commission reversed its decision and exempted imports from AMP. To address potential MW laundering concerns (i.e., internal generators exporting generation in the forward market and offering it back to the ISO real-time market as an import), the Commission required that import bids to the ISO real-time market must be price-takers (bid in at $0/MWh). The Commission also directed that small portfolios should be exempt from AMP once the full network model was in effect and bids below $25/MWh should be exempt from AMP. Finally, the Commission rejected the ISO's proposal not to apply AMP when load forecasts exceed 40,000 MW and ordered that accepted bids at all load levels be included in the reference level calculation. In addition, the Commission ordered that the ISO select an independent entity to perform the task of determining reference prices.

1.1.2.3 Local Market Power Mitigation (LMPM)

Local market power can be exercised when the ISO has to take a resource out of economic merit order to serve local reliability needs. Local market power can occur both in the incremental and decremental bid markets. Local market power mitigation (LMPM) mitigates suppliers' bids in the real-time spot markets and would provide similar mitigation in the forward energy markets once those markets are developed. The ISO proposed that when it must dispatch a unit out of merit order to alleviate intra-zonal congestion, the unit's bid would be mitigated to a proxy price using an estimate of its short-run variable costs. The Scheduling Coordinator for that generating unit will then be paid the higher of its proxy price or the applicable MCP for the incremental dispatch, or charged the lower of its proxy price or the applicable MCP for decremental dispatch. The ISO also proposed to construct a bid curve for each unit based on the cost data submitted by the unit's Scheduling Coordinator.

In the July17, 2002 Order, the Commission rejected the ISO's LMPM proposal and directed that, under the situation where RMR resources are not available and bids must be taken out of merit for the specific purpose of alleviating intra-zonal congestion, the ISO would apply an AMP procedure to mitigate the local market power. Under the July 17, 2002 Order, a bid less than $91.87/MWh that was taken out of merit order would not be subject to any mitigation. If a bid was taken out of merit order and is greater than $91.87, a conduct test would be applied to determine if the bid was $50/MWh or 200 percent greater than the MCP. If so, the bid would be mitigated and the generator would be paid the higher of its reference price or the MCP. An out-of-merit bid (whether mitigated or not) is ineligible to set the MCP.

In its Order on Rehearing and Compliance Filing, the Commission reversed the July 17 Order on the issue of the $91.87/MWh price screen. The Commission removed the requirement of a price screen test when the ISO must take bids out of merit order to address intra-zonal congestion.

The ISO recently submitted a filing to FERC to amend the local market power mitigation provisions (Amendment 50). Under Amendment 50, bids dispatched out-of-sequence in real-time due to local congestion constraints would be mitigated and dispatched based on cost-based bids. This mitigation would apply in both the Incremental and Decremental direction. Incremental dispatches would be paid the higher of the zonal real-time price or the mitigated bid plus 10 percent and Decremental dispatches would be charged the lower of the zonal real-time price or the mitigated bid less 10 percent. The ISO proposed the plus or minus 10 percent factor to compensate for potential inaccuracies in the cost-based bid and potential differences in the variable cost of increasing versus decreasing a unit's output. Amendment 50 was filed with FERC on April 2, 2002 and is still pending before the Commission.

1.1.2.4 Must-Offer

In its May 1, 2002 filing, the ISO requested that the Commission extend the existing must-offer requirement for generating resources within California operating under ISO Participating Generator Agreements.[3] In its July 17, 2002 order, the Commission agreed to extend the West-Wide must-offer requirement. However, the Commission noted that it would consider removing the must-offer requirement in the future if it determines that adequate infrastructure and market design improvements have been made and western market prices reflect competitive outcomes on a more consistent basis.

1.2 2002 Market Redesign (MDO2)

With the demise of the California Power Exchange (PX) in January 2001 and a general recognition that the CAISO's current design is inadequate and flawed in several respects, the ISO undertook a major redesign of its market structure. This initiative is separated into four phases summarized below in Table 1.3.

Table 1.3. Elements of MD02 Phases

Phase	Elements
IA	Comprehensive market power mitigation elements that took effect on November 1, 2002: • AMP • Damage Control Bid Cap • Must-Offer • Local Market Power Mitigation
IB	Real-time Market Redesign: • Real-time Economic Dispatch (RTED) • Ex-post Pricing • Uninstructed Deviation Penalties • Pricing of External Zones
II	Integrated Forward Zonal Energy Market (IFM) • Day-ahead and Hour-ahead Zonal Energy Markets • Simultaneous procurement of energy, ancillary services and congestion management. • Elimination of market separation rule. • Day-ahead and Hour-ahead AMP • Residual Unit Commitment
III	Locational Marginal Pricing • Full Network Model and Nodal Pricing • Local Market Power Mitigation in the forward markets.

[3] PGA generating resources include the utility owned generation and the merchant thermal generation units owned by entities such as Calpine, Reliant, Duke, Dynegy, Mirant, and AES/Williams.

The ISO implemented Phase IA elements on October 30, 2002. They were described in the previous section. In this section, we provide a brief summary of the Phase IB, II, and III market design elements.

1.2.1 Overview of Phase IB Design Elements

The Phase IB design elements relate entirely to the real-time market and include a number of important market reforms, the most significant of which is the implementation of real-time economic dispatch (RTED). In the real-time market, the ISO receives bids to both increase (incremental) and decrease (decremental) generation output. A decremental bid expresses a supplier's marginal willingness to buy energy from the real-time market to replace the generation it is offering to decrease. In other words, if a supplier can buy energy from the ISO's real-time market for less than it would cost to produce the energy from its own unit, the supplier should be willing to decrease its unit's generation and replace it with energy purchased from the real-time market. An incremental bid expresses a supplier's willingness to sell energy to the real-time market. To the extent that submitted bids to buy energy (decremental bids) are higher than submitted bids to sell energy (incremental bids), the ISO could realize economic gains by dispatching these bids (i.e., clearing the bid-price overlap). Under the current real-time market design, the ISO is precluded from clearing the bid-price overlap and, instead, only dispatches the bids necessary to meet system imbalances. Under Phase IB, RTED software will be able to clear any bid-price overlaps in every 5-minute dispatch interval. The software will also include several other refinements to improve the feasibility of dispatch instructions such as allowing for different ramp rates based on the level of unit operation and within hour unit status updates to reflect changes in the status of a unit's operating capabilities (i.e., deratings, outages, etc.).

Another important design element under Phase IB is the implementation of penalties for uninstructed deviations (UDP). Under Phase IB, suppliers who fail to follow ISO dispatch instructions within a tolerance band equal to the greater of 5MW or three percent of the maximum operating limit of the resource will be assessed penalties. The penalty for positive uninstructed deviation from the ISO dispatched operating point (i.e., over-generating) is 100 percent of the market clearing price. This means that suppliers would not be paid for any energy supplied in excess of what was instructed. The penalty for negative uninstructed deviation (i.e., under-generating) is 50 percent of the market clearing price. Suppliers would be charged the market clearing price plus 50 percent for each MWh that is under-produced. These penalties are intended to minimize uninstructed deviations and will help to improve system reliability as well as mitigate the exercise of market power through physical withholding (i.e., not responding to incremental dispatch instructions or producing below scheduled output). Intermittent resources (e.g., wind, solar) and units providing regulation will be exempt from the penalties.

Under the ISO's current market design, it determines real-time prices based on the marginal bid dispatched, regardless of whether that dispatch instruction was actually followed. This would change under the ex-post pricing provisions of Phase IB. Under Phase IB, only resources that have followed dispatch instructions, within a 10-percent tolerance band, will be eligible to set the market-clearing price.

Under the current real-time market design, the ISO determines prices only for the 3 internal zones (SP15, ZP26, NP15). However, there are a number of external zones (e.g., “NW1” equals the northwest zone (Captain Jack and Malin) on the other side of the COI Branch Group interface) that are not priced separately in the ISO’s real-time market. Specifically, if there is real-time congestion between an internal and external zone the ISO dispatches resources to relieve the congestion and the market clearing price for the external zone is set equal to the market clearing price of the internal zone (i.e., no price differentiation during congested periods). The Phase IB market software would determine separate prices for all the internal and external zones and thus provide more accurate pricing and consistency between real-time and the forward congestion markets.

The market power mitigation provisions described in Phase IA will continue in Phase IB with the exception that the price taker provision for imports is modified such that import bids will remain price-takers (ineligible to set the market clearing price) but will be allowed to submit non-zero dollar bids. The local market power mitigation provisions under Phase IA or any potential modifications arising from the Amendment 50 filing, also will continue under Phase IB. The Phase IB market software is currently under design and is expected to be implemented in fall 2003.

1.2.2 Overview of Phase II Design Elements

The Phase II market design primarily involves the implementation of a forward zonal energy market (day-ahead and hour-ahead) and a residual unit commitment process (RUC). The ISO’s current market design has day-ahead and hour-ahead congestion management and ancillary service markets but not an energy market. These markets are run sequentially with congestion management running prior to ancillary services and each ancillary service is procured in sequential order beginning with regulation and continuing through spinning, non-spinning, and replacement reserve. Under the new Phase II market design, markets for energy, ancillary services, and congestion management will be fully integrated and conducted simultaneously. However, the Phase II design will maintain the current zonal structure. Demand in the forward energy markets will be determined by the bids submitted from load serving entities. Self-scheduling of both generation and load will be allowed in the forward energy markets but, unlike the current market design, self-schedules will not have to be balanced (e.g., scheduled generation and imports must equal scheduled load and exports for each SC). Bids from generating units that are not self-scheduled will consist of three-part bids (startup, minimum load, and energy) but only the energy bid will be market based. The startup and minimum load bids will be cost-based. The day-ahead market will run based on a security constrained unit commitment (SCUC) program that will minimize dispatch and unit commitment cost. Units that are committed in the forward energy market will be guaranteed bid cost recovery through a net-of-market revenues approach. Specifically, if the total market revenues earned from a unit over the 24-hour commitment period does not cover its total cost (startup, minimum load, and variable cost), the unit owner will be paid an uplift amount.

The Phase II market design will also include a residual unit commitment (RUC) process that will run first after the day-ahead market and after the hour-ahead market. Since the forward energy markets clear based on submitted demand bids rather than forecasted loads, the RUC process is designed to ensure sufficient capacity and energy is committed to serve the load forecasted for real-time. The RUC process will purchase energy from interties and commit capacity from internal resources to meet forecasted load and reserve requirements.

The ISO will apply automatic mitigation procedures (AMP) in the forward energy markets to address system market power. It will also continue to apply in the real-time market. The damage control soft-bid cap of $250/MWh for the real-time market will also apply to both the forward energy and ancillary service markets. To mitigate against physical withholding, the ISO is also requesting that the must-offer requirements for generators that currently apply to the real-time market be extended to the forward energy markets as well. Since Phase II maintains the current zonal market design, local market power mitigation will be limited to real-time based on cost-based bids similar to the proposed approach under Amendment 50. In addition, re-bidding of energy bids between day-ahead, hour-ahead, and real-time will be limited by the following activity rules:

1. Accepted energy bids in one market cannot be reduced in a subsequent market but can be increased (e.g., HA decremental bids cannot be lower than accepted DA incremental bids).
2. Energy bids associated with awarded A/S and/or RUC capacity cannot be increased but can be decreased in a subsequent market.
3. Internal capacity not selected in an Energy market, A/S, or RUC can be re-bid subject to maintaining a monotonically increasing bid curve.

Under Phase II rules, market participants will be able to hedge against congestion charges through purchasing congestion revenue rights (CRRs). The design, allocation, and ownership entitlements of CRRs are currently under development by the ISO.

1.2.3 Overview of Phase III Design Elements

The Phase III design involves the implementation of nodal pricing (locational marginal prices (LMP)) in both the forward and real-time markets. A crucial feature of the LMP market design is the geographic granularity used for scheduling and settling loads. In its MD02 proposal filed on May 1, 2002, the ISO recognized the equity concerns regarding potentially large LMP cost impacts on loads in constrained areas and proposed a mechanism whereby loads may schedule and settle at aggregation points with prices averaged over all the nodes within specified geographic areas of the grid. In subsequent stakeholder discussions, the ISO decided to modify its aggregation proposal to address more fully and effectively the underlying concerns of market participants. In the present MD02 Phase III design, the ISO proposes to have all loads (that are within the ISO control area and are not served under ETCs) schedule, bid and settle using a scheme of three large aggregation areas based on existing congestion zones and major participating transmission owner service territories. Under this proposal the three load aggregation areas would be a combined PGE3 (equivalent to today's NP15) and PGE4 (equivalent to today's ZP26) area, and the SCE and SDG&E transmission service territories (which today comprise SP15). This aggregation scheme would apply to municipal and direct access loads as well as to loads served by the investor-owned utility distribution companies. Loads would not be allowed to opt out of the aggregation scheme, both to simplify the initial implementation of LMP and CRRs and to address concerns that loads at low-price nodes will opt out and drive up the aggregation average prices so far as to undermine the intent of the aggregation scheme. In addition, the ISO will pay nodal prices to Participating Loads (demand-side resources) for the amount of their real-time curtailment in response to ISO dispatch instructions and will pay nodal prices to generating units.

The same market power mitigation measures provided in Phase II would apply in Phase III as well. However, the local market power mitigation would be expanded to the forward energy markets since these markets will now be nodal and, therefore, will enforce local transmission constraints. As proposed under Phase III, local market power mitigation would apply in the incremental direction in the day-ahead energy market and in both the incremental and decremental directions in the hour-ahead and real-time energy markets. With respect to local market power in the decremental bid market, nodal pricing should provide significant mitigation since generation will be unable to over-schedule in export-constrained areas. However, if there are transmission deratings in subsequent energy markets (hour-ahead and real-time), the ability to exercise local market power in the decremental direction would still exist. Therefore, it is important that local market power mitigation be applied in the decremental direction in these markets.

The local market power mitigation proposed under Phase III is very similar to the current local market power mitigation in the PJM market. Specifically, if resources have to be dispatched to relieve congestion on a non-competitive path, these resources will be mitigated to default bids. For most thermal resources the default bids will be cost-based. For resources for which the ISO does not have cost-based information, it will determine default bids using the following methods, listed in order of preference:

- Mean of LMP prices at unit's relevant location for the lowest priced quartile of prices during unmitigated periods that the unit was dispatched or scheduled over the previous 90-days.
    - Calculated separately for peak and off-peak
    - Adjusted for fuel prices as applicable.

- ➢ A level determined in consultation with the market participant prior to the application of the mitigation.
- ➢ Determined by the ISO based on
  - The ISO's estimated cost of the generating unit.
  - An appropriate average of competitive bids from one or more similar units.

The ISO will determine the resources subject to LMPM based on the location of the resource as follows:

- ➢ A list of transmission lines (or paths) that may cause local market power problems will be **pre-identified and updated periodically** based on an analysis that identifies competitive paths (i.e., paths not identified as "competitive" will automatically be deemed "non-competitive").
- ➢ Based on the power transfer distribution factor (PTDF) (i.e., the shift factors), the ISO will establish a list of resources subject to LMPM for each path and **in each hour** (i.e., dynamically) based on their contribution to the flows on each particular path. Only resources that have a significant impact on non-competitive congested paths will be mitigated.

The initial list of non-competitive paths will be all the transmission constraints modeled in the SCUC except Path 15, Path 26, and the inter-ties. As the ISO gains experience under Phase III operation, it will periodically review the competitiveness of transmission constraints and adjust the list of non-competitive paths accordingly. Specifically, the DMA will analyze market concentration on frequently congested paths that it deems to be non-competitive. If this analysis indicates that some of these paths are in fact competitive, they will be exempted from LMPM in future periods. Conversely, if paths that are deemed to be competitive are determined later to be non-competitive, the ISO will re-designate these paths as "non-competitive".

With regard to the criteria for determining which resources will be subject to LMPM in each hour, the ISO will need to calculate a value of what constitutes a "significant impact" on the flows over a non-competitive congested path. For example, a threshold equal to a 10 percent effectiveness factor would mean that any resource for which a 1 MWh increase in output has a 10 percent or greater impact on the flows of a non-competitive congested path would be subject to mitigation.

Resources mitigated for local market power would be eligible to set the price at their location and would be settled based on the nodal price.