BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning	)))))	R.04-04-003

OPENING COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON THE RESOURCE ADEQUACY PHASE 2 WORKSHOP REPORT

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The California Independent System Operator Corporation ("CAISO") commends the staff of the California Public Utilities Commission ("Commission") and California Energy Commission ("CEC") on their leadership throughout the Phase 2 resource adequacy ("RA") process and on their diligence in producing a comprehensive and cogent Phase 2 Workshop Report ("Report"). The CAISO appreciates this opportunity to provide comments on the Report and assist Administrative Law Judge ("ALJ") Wetzell in formulating a proposed decision that facilitates implementation of an initial iteration of the RA program by the Commission's June 2006 goal.

In accordance with ALJ Wetzell's Notice of Availability, dated June 10, 2005, the CAISO's comments follow the format of the Report and respond, as appropriate, to the questions or topics set forth in Appendix A of the Notice of Availability. The CAISO also complies with ALJ Wetzell's request that any discussion of additional issues follow the responses to the Appendix A topics. The additional subjects were recently discussed at the CAISO's June 22-23 stakeholder meeting on its Market Redesign and Technology Upgrade ("MRTU") project and include: (1) the need to address off-season deliverability; (2) availability obligation of short-start units; and (3) application of RA to "partial units."

I. INTRODUCTION AND SUMMARY

The Report recognizes that RA is currently, and will be for the near future, an evolutionary process. In fact, the Report admits that it addresses "foundational elements" and "transitional features" of the RA framework. President Peevey further emphasized the provisional nature of Phase 2 in his February 28th Assigned Commissioner's Ruling by promoting the ongoing evaluation and development of a capacity market. President Peevey's long-term view was shared by virtually all workshop participants who similarly acknowledged that the efficiency and effectiveness of the durable RA requirement will be enhanced through implementation of some form of capacity market.

The CAISO strongly concurs that a capacity market, whether modeled after one of the eastern ISOs or otherwise, constitutes the best option to implement the Commission's "capacity-based resource adequacy" end state. The Report properly states that the outcome of this proceeding and the selection of transitional elements should be consistent with the development of capacity markets. (Report at 19.) However, it is inevitable that some transitional elements will be superfluous and others, despite best efforts, may be incompatible with the durable RA capacity-based end-state. This reality, as well as the imminent June 2006 effective date, requires that the Phase 2 order focus on key items which (1) minimize implementation time and cost, (2) minimize potential market disruption, and (3) best assure that resources are available when and where needed to maintain system reliability.

Using these criteria, the three components of the initial RA framework essential to the transition are:

- Adoption of the local capacity obligation that incorporates the outcome of the CAISO's local capacity analysis and stated operational requirements. .
- Adoption of the deliverability values developed by the CAISO.
- Adoption of a basic compliance program.

The Report states that the "the primary purpose" of the Commission's capacity-based resource-adequacy requirement "is to provide for a sustainable revenue stream over time that is missing from the capped energy markets so that physical generation remains economically viable to be available when and where required and that new resources come online in a timely fashion." (Report at 7.) The local capacity obligation constitutes the single most vital factor in achieving RA's stated objectives in the near-term transition period for several reasons.[1] First, under the CAISO's proposed Market Redesign and Technology Update ("MRTU") project, units in load pockets are most at risk of being subject to bid mitigation. (See, e.g., CAISO White Paper: Market Power Mitigation Issues for Resolution in the Summer 2005 Stakeholder Process, May 11, 2005.) The CAISO's local capacity study criteria identified the minimum quantity of capacity necessary to maintain reliable grid operation under diverse, but not all, system conditions and major contingency scenarios. In doing so, the CAISO's study defines an obligation for load serving entities ("LSEs") to procure in load pockets that encompasses many, and in some local areas most, of the units that require a capacity payment to remain economically viable. The local capacity element, therefore, greatly advances both the adequacy and security objectives of the Commission's RA requirement.

Second, the local capacity obligation is defined in a manner that builds toward the desired capacity-based, possibly eastern-style ISO RA requirement. It does so by limiting eligibility to physical, identifiable resources that must make themselves available to the

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[1] It should be noted that the CAISO views the local capacity obligation as transitional for many local areas. The CAISO is committed to identifying and encouraging the development and construction of <u>economic transmission solutions</u> to eliminate transmission constrained load pockets. The CAISO believes that consumers can benefit from expanding energy markets that result from the cost-effective removal of local transmission bottlenecks.

CAISO at all times, subject only to legitimate physical constraints and forced and planned outages. The details of the availability obligation are further set forth below and the experience gained in contracting to comply with this requirement can be utilized to facilitate the development of mutually agreeable commercial terms for future capacity-based transactions.

Third, and a corollary to the foregoing, the adoption of the CAISO's local capacity obligation moderates the incompatibility of the Commission's capacity-based RA end-state and any interim eligibility of certain existing contractual supply arrangements, e.g., "Firm LD" contracts. Firm LD contracts defeat the purpose of RA by, among other things, often failing to include a capacity component in its pricing, preventing an effective deliverability assessment, and obfuscating the source of generation, which can lead to double-counting of capacity. The CAISO believes the Commission should establish a bright-line rule prohibiting intra-control area system contracts entered into after the date of the Phase 2 decision from qualifying as RA capacity.[2] Accommodation for existing contractual resources should be made and Firm LD arrangements should remain an effective energy hedge in an LSE's portfolio.

Local capacity is essential, but insufficient in and of itself, to ensure reliable operation of the grid. Overall system conditions and load must be met. In the interim, to the extent existing contractual resources are to be accommodated, it is important to prevent reliance on imports at a level incompatible with the system's physical realities. The CAISO's assessment of import deliverability rests on historical, and therefore viable, import levels. Accordingly, the Commission must adopt the CAISO's import deliverability analysis as an essential feature of its Phase 2 order.

Finally, the CAISO does not hold out much optimism for the success of a RA system based on a "trust us" approach. A central function of the RA requirement is to provide a revenue stream that induces infrastructure investment by permitting suppliers to receive their going forward fixed costs not provided by mitigated energy markets. Simply put, RA has a cost. LSEs will naturally attempt to avoid these costs. Accordingly, the RA requirement must have an economic consequence for non-compliance or it will fail. Yet, compliance poses the greatest challenge in the near term. The Report correctly acknowledges that any compliance feature cannot, and should not, place the CAISO in the position of having to interpret bilateral contracts or accommodate myriad operating and contractual limitations. The CAISO offers several options that avoid this consequence.

[2] The CAISO notes that D.04-10-035 accepted as RA capacity system import transactions deliverable at an inter-tie that satisfy certain requirements. System contracts, whether designated for delivery at inter-ties or scheduling point(s) internal to the CAISO Control Area, should be identified in the LSEs RA report whether the contract quantity will be credited toward the LSE's import allocation.

II. RESPONSES TO QUESTIONS SET FORTH IN REPORT

2.A.1. The CPUC Staff / CAISO Proposal To Define Buyer And Seller Obligation

2. *The Commission must determine whether to adopt the CPUC staff / CAISO proposal to make the RA obligation applicable to both LSEs and suppliers of RA resources.*

In his ACR on Capacity Markets, President Peevey recognized that "[a] centralized capacity market may make compliance and enforcement of the RAR more manageable." (ACR at 4.) It does so, in large part, because of the ability to clearly delineate and assign separate obligations to LSEs and suppliers through a centrally administered tariff. The Report acknowledges that the Commission staff/CAISO proposal to "split" the RA obligations between LSEs and suppliers "builds on the experience in the Eastern markets." The CAISO strongly agrees with President Peevey that the RA end-state should include some form of centralized capacity market and, as such, supports the Report's proposed assignment and general definition of parties' respective long-term RA obligations.

However, the Commission's Phase 2 order must permit the efficient implementation of RA on June 2006. The Report fails to clearly indicate whether the split obligation proposal is intended to apply immediately during the transition period and to what extent, or simply to establish guidance for continuing capacity market design efforts. If the former, the CAISO has several observations. First, the obligation on the generator to have its quality capacity linked to performance cannot be realized in the short-term. As discussed further below, eligibility for capacity payments cannot be linked to performance of individual resources during the initial implementation in June 2006. Inclusion of performance standards are critical to the success of RA and must be part of the durable end-state, but development of these standards realistically preclude imposing any performance metric on suppliers at this time.

Second, the likely decision to grandfather existing resources will greatly impact implementation of the split obligation. The Report states that "LSEs must obligate the seller to abide by the requirements in the CAISO tariff that the generator must meet." (Report at 24.) Even assuming the appropriate RA provisions are included in the CAISO tariff in time for June 2006, LSEs will not be able to "obligate" their existing resources to comply with these provisions absent contractual amendment. It is unrealistic to assume that all existing resource arrangements would be reopened and modified between the time of the Phase 2 order and the LSE showing (if assumed to be 90 days after the Phase 2 order).

Third, the fundamental characteristic of a Firm LD contract is that the supplier need not identify a particular resource to satisfy the delivery obligation. There is likely to be substantial complexity and variability in the terms of these contracts – e.g., when can they be called, with what notice, under what other terms? The CAISO cannot be placed in a position of having to interpret bilateral contracts and then accommodating myriad operating and contractual limitations in the forward markets and real time to establish a "customized" must-offer obligation for such resources. As such, RA obligation of any resource may change day-to-day and hour-to-hour because a resource supplying an RA contract may or may not be a RA listed resource. Thus, the obligation to be listed and to bid into the CAISO's day-ahead market may not apply to Firm LD suppliers.

During the transition period, when Firm LDs are eligible to count as RA capacity and a standard product is not defined either through the CAISO's tariff or through the market, the CAISO offers two alternative approaches. The first adopts the Report's allocation of compliance functions between the CAISO and Commission, but with a modification. The CAISO can track compliance with local capacity and all other physical capacity whether or not subject to use limitations and a use plan. The characteristics for local capacity are discussed in detail in the CAISO's RAR Local Capacity Procurement Straw Proposal, attached hereto as Attachment A.[3] However, with respect to other contractual arrangements, if the physical resources supporting the RA contract are not identified before the close of the day-ahead market, the CAISO proposes that LSE's relying on such RA contracts assume cost responsibility for any resulting consequences. Specifically, this includes a share of start up and minimum load cost associated with non-RA resources that the CAISO may incur to ensure enough units are on line to meet its day-ahead load forecast. The share is based on the amount of RA contract volume that remained financial (not tied to a physical resource) in the day-ahead market. Since financial contracts can be used for system-wide RA only (all local RA must be physical), this allocation is in line with MLCC cost allocation of Amendment 60 and represents a refinement to allocate the cost to the zonal load on a LSE specific basis**.** This same cost allocation could also persist after implementation of MRTU and RUC.

Further, if the resource is an import schedule (at a designated scheduling point), the obligation to make the resource available in the day-ahead market should rest on one party that agrees to act on behalf of both parties to schedule or bid the relevant import.

A second option is to focus on defining and enforcing LSE obligations after the fact based on their performance in the day-ahead, hour-ahead and real-time markets. Each LSE is obligated to secure resources, and to bid or schedule those resources in amounts sufficient to serve their load. Each LSE provides the CAISO with information on the resources and the responsible SCs that are meeting their RA requirement. The CAISO can verify <u>after the fact</u> that the LSE scheduled and bid sufficient resources in each hour to serve its load and provide whatever portion of the 15% reserve may remain after consideration of load forecast error, forced outages and any other eligible adjustments. This approach ignores resource constraints and places responsibility on the LSE in how it schedules and bids its resources, including management of energy-limited resources. Resource performance would be enforced through the existing tariff terms – Uninstructed Deviation Penalties, No Pay for Ancillary Services and the CAISO's Enforcement Protocol.

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[3] For the record, in addition to Attachment A, the CAISO includes the following: Attachment B – Local Capacity Technical Analysis: Overview of Study Report and Preliminary Results (June 23, 2005) and Attachment C – Preliminary Deliverability Baseline Analysis Study Report (May 3, 2005).

Another component of an after-the-fact review is the imposition of a penalty on LSEs who are short of meeting their RA obligation and end up relying on the CAISO's real-time spot markets. Those LSEs will be charged a multiple (e.g., 3 times) the spot market price, whereas those that were not short would pay the regular price. The advantage of this penalty system is that it is tied to the market impact of insufficient RA.

3. *The Commission must also decide whether a qualified resource should count for the life if its contract with the LSE, even it is de-rated is subsequent years due to performance.*

The CAISO strongly believes that creating a fixed level of qualifying capacity during the life of an agreement improperly bestows resources a "free ride" with respect to availability and performance in contravention of the foundational RA goal of promoting reliability. Incentives for maintaining and operating units efficiently must be part of the durable resource adequacy paradigm. As noted by the Report, "[q]ualification to be a RA resource should provide an incentive for plant investments/upgrades and a reduction in forced outage rates thus holding the potential to lower the overall reserve requirement and costs." (Report at 27.) Virtually all regions implementing a formal resource adequacy program include performance metrics that affect qualifying capacity. In D.04-10-035, the Commission committed to evaluating performance metrics in the "second generation" of RA. California should not be in isolation on this element and the Commission should not take action inconsistent with the Commission's prior commitment.

The primary argument in favor of maintaining the level of qualified capacity of a resource over the life of an agreement, irrespective of generator performance or availability, is that de-rating the capacity would undermine the objective of encouraging long-term contracting. This justification is overstated and should be ignored. If the rules for de-rating are reasonably clear, market participants can mutually agree upon an acceptable allocation of performance risk within their agreements. As such, the implementation of performance metrics for determining qualifying capacity should not establish a barrier to long-term contracting.[4] The CAISO does not believe, however, that the Commission[5] should attempt to apply the specific means to measure performance and

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[4] The Report notes that the planning reserve margin ("PRM") "may warrant adjustment after gaining experience with measuring performance of RA resources." Modifying the PRM to reflect system performance follows the practice employed by the Eastern ISOs. However, the Eastern ISO's have performance incentives (i.e., §4.5 of the NYISO Installed Capacity Manual) and generally utilize a "loss of load expectancy or loss of load probability" of one day in ten years that takes resource performance, import limitations, and internal resources into considerations (i.e., §2.3-2.5 of the NYISO Installed Capacity Manual). The CAISO advocates implementing a similar LOLP or LOLE methodology as the means to adjust the PRM in the future following experience with the RA program.

[5] The Report states that "[t]he specific means to measure performance and the process for determining the qualifying capacity has not yet been defined by the CAISO." (Report at 27.) The implication that the CAISO has been dilatory in this regard is unwarranted. The Commission explicitly assigned this topic to the Commission's "second generation" RA efforts. (D.04-10-035 at 48.) Accordingly, not only is it unclear whether this matter is ripe for development, but it is also unclear that the Commission has delegated this responsibility to the CAISO.

the process for determining qualifying capacity for compliance-year 2006 (consistent with D.04-10-035). The Commission should immediately upon conclusion of Phase 2, and perhaps as part of the investigation of capacity markets, begin the process for defining the performance metrics. In the meantime, the Phase 2 decisions should require that all RA qualifying contracts entered into after publication of the Phase 2 decision must include a provision permitting incorporation of any future Commission rule or CAISO Tariff provision linking qualifying capacity to performance of individual resources.

If the rules for de-rating qualifying capacity on performance are clearly defined, it follows, consistent with the markets implemented in the eastern ISOs, that an "installed reserve margin" would be converted to an "unforced capacity requirement." However, prior to making such a conversion, the installed planning reserve margin should be established based on a "loss of load probability" analysis of, on average, no more than once in ten years. The LOLP approach provides great value because the Commission would be effectively determining the level of reliability that is expected from the RAR. The current, static PRM does not consider the effect of system performance changes, including the appropriate PRM if new, more reliable resources are constructed.

2.A.2.2. CAISO Commitment Of Resource Adequacy Resources

4. *The Commission must determine whether to take the position that an extension of theMust-offer and associated waiver process is necessary to facilitate commitment of RA resources until MRTU is implemented, and if so what cost information for RA resources will be presented to the CAISO to factor into their dispatch decisions.*

Any order by the Commission must recognize that the current FERC must offer requirement represents two distinct elements: (1) an obligation that if certain units either do not schedule/bid all capacity into the CAISO markets, they must apply for a must offer waiver from the ISO, and operate/bid units into the CAISO's real time market if the CAISO denies this waiver request, and (2) a process by which the CAISO receives waiver requests, issues approvals or denials, and then provides compensation for any units that are denied a waiver and operate in real time. So, there are two parts to this question: (1) whether to extend the existing must offer obligation and (2) whether there is a need for the must offer waiver process. These are addressed separately below:

(1) Extension of the Obligation

Prudence and common sense suggest that dramatic regulatory changes should not be implemented without some test period or backstop mechanism. This reasonable philosophy supports deferring whether the must offer obligation should continue until after the RA requirements are specified, information on efforts by LSE's to procure resources to meet the requirements is available, and experience with operation of the grid pursuant to the RAR is gained. A countervailing concern is that the existence of an overlapping must-offer backstop will dilute the incentive of LSEs to contract with resources. While the CAISO acknowledges suppliers' concerns, the CAISO believes that on balance the must-offer obligation should be eliminated only after the RAR has been in place for some time and the CAISO gains confidence that sufficient resource have been procured and will be made available to the CAISO to ensure system and local reliability in real time. Based on the current schedule for RAR implementation starting in June 2006, the CAISO anticipates that it may be impractical to gain sufficient experience upon which to determine the efficacy of maintaining the must-offer obligation until after the summer of 2006. Thus, there may be a relatively narrow window of time between the point when the CAISO can determine whether there is a continuing need for the must-offer obligation, and the implementation of MRTU in February 2007.

Ultimately, the Federal Energy Regulatory Commission ("FERC") will determine whether or not the must-offer obligation endures beyond implementation of RAR. Consistent with the foregoing, the CAISO anticipates advocating before FERC that the must-offer obligation not automatically terminate upon implementation of RAR in June 2006, but that the CAISO seek its termination at the earliest possible time thereafter, which as a practical matter is unlikely to be prior to implementation of MRTU.

(2) The Must-Offer Waiver Process

The must offer waiver process – or some modified version of the process – must remain in place until implementation of an alternative day ahead security constrained unit commitment mechanism as part of MRTU. Simply put, since there is no forward energy market and no formal unit commitment service in the day-ahead market prior to MRTU, the must offer waiver process to ensure adequate units are committed to meet the ISO's load forecast is necessary. The CAISO's ancillary services market fails to offer a viable alternative. Ancillary services constitute a high quality product, i.e., 10-minute responsive, and the amount the CAISO must obtain is based on Minimum Operating Reliability Criteria (MORC) around 7% of load forecast. Must-offer waiver capacity generally addresses underscheduled load, which need not all be satisfied by 10-minute responsive supply. Energy from the must-offer capacity can be predispatched to meet projected need. Buying more ancillary services (high quality product) instead would encourage generators to increase the ancillary services price (i.e., increasing the demand against a fixed supply curve) and exacerbate any market power suppliers may already possess in the CAISO's ancillary services markets. Moreover, the ancillary services market is not a unit commitment market and does not consider start-up and no-load costs. Thus, it is possible to call on a resource for say 10MW of ancillary services, but that amount is below its minimum load of the unit.

5. *The CPUC must decide whether to adopt (or modify) the SVMG working proposal for standard contract language. The CPUC should consider how any changes to standard contracting elements should be incorporated into the Renewable Procurement Standard (RPS) contracting process.*

The CAISO supports the formulation of a standard capacity product. The creation of standardized capacity product is critical to measuring compliance and ensuring enforcement under a capacity oriented the top-down or bottom-up approach (under the bottom-up the product may have a menu of several different temporal terms, i.e., 6x16, 5x8, etc.). Nevertheless, the CAISO believes it is premature for the Commission to formally adopt the specifics of the SVMG contract/confirm language. The SVMG capacity product proposal verifies, however, that once the Commission has established the attributes of eligible capacity, the market will respond expeditiously.

The Report emphasizes Commission staff's understanding that D.04-10-035 "adopted a capacity-based resource adequacy requirement." As a general matter, the Joint Parties "Proposal for Load Forecast and Year/Month Ahead Showing That Supports an All Hours RAR," served on April 27, 2005, sets forth a proper foundation for the defining the attributes of RA capacity. The Joint Parties identified three attributes: (1) capacity is deliverable to CAISO load; (2) capacity is verifiable and physical; and (3) capacity is available to the CAISO markets. The CAISO notes that under the durable RA paradigm, the physical capacity must be verifiable at the time the LSE makes its ex ante showing of RA compliance. A financial contract that may ultimately become physical, but does not identify the unit associated with the contract at the time of the showing, does not meet the definition. This precludes the intra-control area system or "Firm LD" contracts from counting towards RAR. Therefore, while the Commission may agree to count certain existing resources as RA capacity during some transition period, the durable definition of capacity adopted by the Commission should facilitate procurement of capacity resources that comply with the RA end-state that anticipates an organized capacity market.

Section II, entitled "Essential Elements," of the SVMG proposal also sets forth appropriate definitional details that should guide the Commission's opinion on the attributes of RA capacity. Nevertheless, the CAISO has several clarifications of SVMG's view of the "availability" obligation. First, to the extent the Contract Quantity is not unavailable due to a forced or planned outage, the Contract Quantity (or the remaining portion) must be fully accounted for either as (1) scheduled energy to load within the CAISO, (2) scheduled to provide day-ahead Ancillary Services, or (3) with respect to any residual Contract Quantity not scheduled, bid into the CAISO's real-time energy and Ancillary Services markets. Second, as explained in Part II of these comments, and contrary to SVMG's Section II.5.C.i.2, short-start units will not be eligible for a must-offer waiver either before or after implementation of MRTU. Short-start units are those with an ability to perform a cold start in less than 2 hours and must remain available to the CAISO through real-time. Third, again, with respect to short-start units, the absence of accepted Ancillary Services bids in the day-ahead does not excuse the unit from participating in CAISO markets through real-time. (See, II.5.d.i.)

Moreover, as the Commission is well aware, the parties are divided on whether the CAISO should pay an availability payment to all capacity that is committed in the MRTU residual unit commitment ("RUC") process. The recent FERC Order regarding the CAISO's MRTU briefly addressed the issue of RUC availability payments. [cite page 136] It appears that FERC is seriously considering that all resources that are available in the RUC should be paid an availability payment based on the clearing price for RUC capacity. To the extent the Commission wishes to ensure the RA resources are committed based on zero price, then the RAR contracts should require the resource to bid at a zero price. The CAISO has consistently taken the position that RA resources would be flagged in MRTU and would have a zero priced bid for availability consideration in RUC. As a practical matter, this would result in RUC clearing prices of $0 for those hours where sufficient RA capacity exists. In those hours where additional capacity is necessary and the capacity participates with an availability bid greater than zero, then the RUC clearing price would be paid to all resources. However, to avoid the possibility of paying for the capacity twice – once through the RA contract and again through the availability payment, the RA contract must provide for CAISO availability payments to be credited back to the LSE.

3.A.1. CEC Review Of Preliminary Load Forecasts

6. *The CPUC must decide the process it will pursue in the event that the CEC highlights noncompliance issues associated with forecasting. Parties are asked to propose options to safeguard against non-compliance.*

7. *The CPUC must decide whether to provide for a process for LSEs to resolve disputes with the CEC in the event there is disagreement regarding the forecasts. The CPUC must outline the process.*

8. *The CPUC must decide whether it will formally adopt the CEC forecasts and the associated resource adequacy obligation on a yearly basis. Or in the alternative, the CPUC may want to decide whether it's appropriate to delegate the task of formally adopting forecasts to the CEC in the Phase 2 final decision.*

9. *The CPUC must decide how the formal yearly adoption of the forecast and reserve obligations will work with the timing of the reporting requirements to allow LSEs sufficient time to meet the obligation.*

The CAISO does not believe it prudent or necessary to include an after-the-fact enforcement mechanism to combat the threat of inaccurate data submissions and other potential abuses by LSEs with respect to forecasting requirements. In D.04-10-035, the Commission rejected the "current customer" approach to load forecasting advocated by the IOUs, the CAISO and TURN. Instead, the Commission adopted the "best estimate" approach. The current customer approach offers a more straightforward and simple methodology for developing LSE obligations involving less LSE subjectivity (i.e., assessment of future commercial relations) and, therefore, affords less opportunity for abuse. The Commission recognized the possibility of gaming under the best estimates approach and stated an intention to "establish a tracking system that compares forecasts with actual loads and creates penalties for excessive deviations." (D.04-10-035.) However, delineating in advance a bright-line for what constitutes an excessive deviation is likely to be highly contentious. The use of a 1 in 2 year forecast and the timing of the forecast well in advance of the relevant operating period will inevitably lead to divergence between the forecast and actual loads and adding some acceptable "headroom" to prevent penalizing good faith error may compel acceptance of a significant deadband. The creation of this deviation deadband will serve only to insulate and encourage inaccurate forecasts in the amount of the deadband.

The eastern ISOs do not employ after-the-fact load-forecasting penalties. Two factors seem to underlie the absence of a penalty mechanism, both of which are applicable to California's situation. First, the eastern ISOs rely on the soundness of the forecasting methodology, the expertise of the forecasting entity, and an expeditious ex ante dispute resolution mechanism. The CEC was selected to develop LSE forecasts as a means to leverage the CEC's expertise in this area. Accordingly, the CEC should be given the authority to exercise this expertise to determine each LSE's RA load obligation. The CEC's determination, whether through Commission delegation or summary adoption, must be binding on the LSE and subject only to an expedited ex ante dispute resolution procedure.

The CAISO recognizes that, in part, any forecasting expertise depends on the presence of historical or background data of sufficient quality to allow the CEC to generate accurate forecasts and identify aberrant LSE forecasts. In this regard, D.04-10-035 directed LSEs to provide the Commission and the CEC hourly forecasted load data as well as "their up-to-date accounting of their current customers and loads." The data should also include customer contract termination dates. Subject to appropriate safeguards for confidentiality, the CAISO proposes to work with stakeholders and the CEC to allow the CEC access to Settlement Quality Meter Data for Scheduling Coordinator load.[6] Accordingly, the CEC should be given the authority to exercise this expertise to determine each LSE's RA load obligation. The CEC's determination must be binding on the LSE, subject to an expedited dispute resolution procedure.

The CAISO proposes the following dispute resolution procedures that are based on the NYISO and consistent with the draft "critical path" timeline set out in Table 1 of the Report. The Report timeline has LSEs submitting forecast data to the CEC in May. The CEC prepares forecasts in June and, under the timeline, makes forecast adjustments and reports problems to the Commission in July. Given that local capacity procurement is on an independent track, the timeline appears to provide the LSEs with approximately 3 months to procure in compliance with the CEC July forecasts. Under the following, LSEs will continue to have 3 months to procure, except that to the extent incremental load is disputed, the timeline for that procurement is reduced to approximately 2 months (it is assumed the LSE will not procure the disputed amount until after dispute resolution).

Date	Activity
July 1	CEC publishes forecasts
July 6	➢ LSE provide written response of error if informal attempt at resolution fails ➢ Select arbitrator
July 11	CEC provides written reply

[6] The CAISO recognizes that some SCs represent multiply LSEs so that the SC would have to submit the SQMD unaggregated.

July 26	Arbitrator provides opinion

The CEC or Commission shall keep a list of at least ten (10) qualified arbitrators. These arbitrators should be selected at a Commission workshop held for that purpose. The arbitrator shall be selected randomly from the list until an available arbitrator is found. The cost of the arbitrator shall be borne by the disputing LSE. No person shall be eligible to act as an arbitrator in any dispute in which he or she was a past or present officer, employee of, or consultant to any of the disputing parties, or of an entity related to or affiliated with any of the disputing parties, or is otherwise interested in the matter. There shall be not right to discovery. However, the arbitrator may request additional information. The arbitrator can resolve the matter solely on the basis of written material, but may, at the arbitrator's discretion, hold a one (1) day hearing. The decision must be made within 20 days of the appointment of the arbitrator. The decision of the arbitrator shall be final and binding, except that an appeal can be made on grounds of fraud or demonstrable bias. An appeal does not stay the arbitrator's decision. (See, NYISO § 5.16.)

This is unlikely to be overly burdensome in that the disputes will generally relate to an incremental portion of the LSE's load obligation. In addition, over time as the LSEs and the CEC refine their analyses and expectations, the level of disputes should diminish. More importantly, under a centralized capacity market, the current customer methodology is generally applied because load migration can be accommodated through monthly true ups that are facilitated by the presence of a residual auction. Consequently, by transitioning to a centralized capacity market, the disputes over forecasting should inherently diminish.

3.A.3. CAISO & CEC Preparation Of After-The-Fact Performance Reports

10. *The Commission must decide the process for determining whether sanctions are warranted in the event that the CEC determines that load forecasts were inappropriate, or alternatively, whether there is a more upfront means to provide LSEs with their capacity procurement target that reduces the need for after-the-fact second-guessing and potentially a burdensome Commission process for sanctions. As discussed in Section 6.D. and 6.E., the Commission must decide whether, and to what extent, the CAISO should have the responsibility for enforcing the RAR.*

Above, the CAISO responds to the issue of establishing sanctions for load forecast error and how to eliminate after-the-fact second-guessing. Here, the CAISO responds to the question regarding the whether, and to what extent, the CAISO should have responsibility for enforcing RA forecasting responsibilities. Enforcement of LSE obligations during the interim transitional period, including those relating to load forecasting and ex ante procurement obligations are properly within the jurisdiction of the Commission. The CAISO assumes that the Commission will reexamine the CAISO's role in enforcement, on both the load and supply side, as part of President Peevey's ongoing evaluation of capacity markets.

3.B.1. CAISO Periodic Assessment Of Local Capacity Requirements

11. The CPUC and CAISO must work to ensure that the determination of the local capacity requirements are coordinated with the overall RA timeline.

The CAISO's response to this question first addresses the procedural aspects or timeline for implementing the local capacity requirements and second address issued concerning the scope of the local capacity obligation.

Local Capacity Timeline

Period 1 – Before RAR Implementation

The CAISO intends to use the current Reliability Must-Run ("RMR") criteria to designate RMR Units in the 2006 Local Area Reliability Service ("LARS") process and will propose a policy as described below to integrate the LARS 2006 process with the Commission's RAR local capacity process. Under current RMR contract, the CAISO must provide notice of any extensions to the applicable RMR Owners not later than October 1, 2005 for the 2006 Contract Year. The CAISO will not know whether the extensions should be for less than a calendar year prior to October 1; therefore the CAISO intents to extend the 2005 RMR Units identified as required to meet the RMR Criteria for the entire 2006 Contract Year. If an LSE contracts with an RMR Unit designated for 2006 that meets the local RAR capacity requirement in terms of location, characteristics, and dispatch rights, the CAISO would be willing to terminate the RMR Agreement as to those RMR Units early with mutual agreement of the RMR Owner. To facilitate this, any agreement between the LSE and RMR Unit Owner designed to meet the RAR local capacity obligation should stipulate that the RMR Unit Owner be willing to mutually agree with the CAISO to terminate the RMR Agreement effective midnight on May 31, 2006. If capacity procured by the LSEs does not satisfy the local capacity requirement, the CAISO would continue to rely on the RMR Units, both extended and newly designated for 2006, and the existing must-offer process in addition to the RAR capacity procured by LSEs.

Period 2 - Beyond 2006

The implementation of LARS and its relationship to the RAR process for years beyond 2006 will be determined after the Commission issues a ruling on the RAR. When the must-offer obligation is no longer applicable and the RAR is fully implemented, the CAISO would execute a new reliability contract for any capacity required to satisfy the local capacity requirement to the extent LSEs have not procured sufficient capacity. With respect to the timing issues presented above, the first issue will be resolved because the Commission's RAR local capacity obligation should apply for the entire year beginning in 2007. However, the timing of the CAISO's procurement will remain an issue in future years. There are two potential alternatives: (1) request that the date by which the Commission requires LSEs to provide the showing for 2007 and beyond be advanced to September 1 or earlier each year for local capacity purposes (this would provide sufficient time for the CAISO to designate and execute a new reliability agreement for any additional units required to satisfy the local capacity requirements or (2) the new reliability Contract Year would be shifted to accommodate the September 30 date. The CAISO prefers the first of these two.

Proposed Future LARS and RAR Schedule

End of January	CAISO requests base cases and load forecast for the following year from the TOs and LSEs.
February-March	TOs develop Base Cases and Load forecast for the following year.
End of March	TOs provide complete local area and system base cases and load forecast for the following year to the ISO. [TOs already submit this information along with proposed transmission projects as part of their participation in the CAISO's transmission planning process.]
April-May	CAISO performs RAR Technical studies to determine the local areas and the capacity requirements (in MWs) within those local areas.
May	CAISO issues Draft RAR technical study which identifies the capacity requirements in each local area.
May	CAISO conducts Stakeholder Meeting(s) to discuss these RA locational Requirements.
End of May	CAISO issues Final RAR technical study with locational requirements.
End of May	CAISO issues RFP for back-up reliability contracts.
June-July	LSEs review options for meeting locational requirements and make procurement.
Beginning of August	CAISO receives LSE management decisions regarding their capacity contracts for meeting locational requirements.
Beginning of August	Deadline for responses to CAISO's RFP for back-up reliability contracts.
August	CAISO evaluates LSE decisions and proposals for CAISO back-up reliability contracts.
End of August	CAISO management issues draft recommendation for CAISO back-up reliability contracts.
September	CAISO issues final recommendation for back-up reliability contract designation.
September	The CAISO Board acts on Management's recommendation.
September 30	Notices of cancellation to be issued to units not needed for next year.
September 30	LSEs' year-ahead showing for locational capacity requirements.
October	CAISO modifies or signs back-up reliability contracts and prepares FERC filing.
November 1	CAISO files with FERC on rates and back-up reliability contracts, as required for 60-day notice.
January 1	Back-up reliability contracts take effect.

Local Capacity Requirements

- CAISO recommends that the Commission adopt the CAISO proposed Local Capacity methodology because it provides the system security that should be a result of an effective resource adequacy program.

During the June 29th stakeholder meeting, many stakeholders were concerned about the quantity of capacity required as a result of the CAISO's technical analysis to establish local capacity requirements. The CAISO's technical analysis to establish local capacity requirements applies criteria that include BOTH planning and operating criterion in a manner consistent with NERC/WECC standards. The CAISO described the operational impacts if certain contingencies were not accounted for in the local area analysis. The purpose of the local area capacity requirement is intended to define the quantity of capacity necessary to support real-time operations. Indeed, the Report appears to recognize that the reliability goals underlying the RAR must be addressed by stating, "[t]here must be enough resources to meet customer needs (adequacy) and enough of that capacity must be available when it is required (security)." (Report at 19.) The CAISO supports this characterization of the roles of adequacy and security. How capacity is actually dispatched should be a function of the CAISO markets. However, these markets cannot ensure system security unless sufficient infrastructure exists prior to the real-time need.

In particular, some parties were concerned about the application of operating requirement that considers the loss of two transmission lines after the loss of either a generator or transmission line. This scenario has the appearance of planning for a loss of three transmission elements. Current NERC/WECC planning criteria allow for load shedding under such a contingency and would not mandate construction of new transmission infrastructure. However, NERC/WECC operating criteria require that after the loss of a single element the system operator must readjust and prepare for the next major contingency. As a result, the system operator must have additional infrastructure available, otherwise it will be forced to curtail load prior to the contingency. It should be noted that only one of eleven identified load pockets is affected by the operating criterion. Specifically, for the Los Angeles Basin the South of Lugo, the operating criteria considers the impact on load in southern California after the loss of one line and the potential loss of two additional 500kv lines. The Commission is familiar with this scenario as it dealt with these reliability needs in D.04-07-028 on IOU procurement practices.[7]

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[7] A corollary to the application of planning and operating criteria for determining local capacity obligations is the observation by stakeholders that because NERC/WECC criteria may permit load curtailment by manual or special protective systems in certain circumstances, the planning process would not attempt to identify a transmission solution. The RA deliverability analysis provides a tool to identify the contingencies and solve the problem by appropriate infrastructure levels, including demand response if capable of meeting NERC/WECC requirements for operating reserves. The selection of the appropriate resource to address an identified reliability concern need not be addressed immediately, but the issue must be addressed for the long-run efficiency of RAR and the Commission's integrated planning processes. The CAISO recommends that the Commission add this issue to the items that will be addressed in subsequent RA phases.

Finally, it should be emphasized that the foregoing contingency, if left unaddressed, would have a major, long-term major impact on the ability to serve load because on the size of the MWs affected and the potential length of time to reconstruct the transmission system in the event such conditions occur. Yet, even with this conservative criterion, sufficient capacity exists in the eastern Los Angeles Basin to meet the requirements and therefore no new capacity is required to be constructed. In sum, the Commission should approve the local area capacity methodology because it is an effective means to identify whether sufficient resources exist to meet customer needs (adequacy) based on the NERC/WECC planning and operating standards (security).

Local Capacity Operating Characteristics

For the operating characteristics of local capacity, please see Attachment A.

3.B.2. CAISO Modification Of Its Current Reliability Must Run Contract Process To Backstop Resource Adequacy-Based Local Capacity Procurement

12. *The CPUC must affirm that local resource adequacy requirements imposed by the Phase II decision are intended to replace existing RMR contracts. The CPUC, CAISO and FERC must coordinate the transition out of the existing RMR contracts to local RA requirements. These agencies must also coordinate to assure that CAISO backstop procurement cost allocation provides the correct incentive for LSEs to comply with RAR and minimize the CAISO's role in procurement.*

The CAISO appreciates the Commission's concern that the cost allocation rules developed by the CAISO and approved by FERC with respect to the Local Area Reliability Contracts ("LARCs") do not undermine LSE incentives contract with local capacity and minimize reliance on the LARC backstop mechanism. Generally, the cost allocation rules should conform to cost causation principles, which will vary depending on the reason for the CAISO's LARC intervention. Where the CAISO utilizes the LARC to make up for one or more LSE's inability (i.e. market power) or unwillingness to procure the quantity necessary to satisfy their allocation of the capacity requirement for that particular local area, the CAISO anticipates allocating the cost of that contract to the deficient LSEs with an obligation in the particular local area.[8] As previously noted by the CAISO, it is also possible that the CAISO may be compelled to utilize LARC if, despite LSE procurement of their local MW obligation, the configuration of units under LSE contract does not allow the CAISO to meet the criteria underlying the local capacity obligation. The CAISO does not believe this will occur frequently and the CAISO will attempt to minimize its likelihood by identifying those units in each local area that must be procured to satisfy reliability or operating criteria. Given that all LSEs with a local obligation in the local area satisfied their requirement, but additional capacity was

[8] Of course, the Commission must ensure LSEs make the necessary procurement by establishing an appropriate penalty for failure to comply with the RAR.

required for reliability, the cost of such LARC contract should be allocated to all LSEs based on the ratio of each LSE's obligation to the total local area requirement. Finally, while the CAISO does not anticipate the need to procure capacity except to fulfill local capacity requirements, it CAISO cannot present preclude the possibility that a circumstance could arise that requires the CAISO to intervene by procuring "system" capacity. The reason for this unlikely intervention would have to be evaluated to determine the appropriate allocation consistent with cost causation principles.

Moreover, in D.04-10-035, the Commission noted that although RA was an essential service for California, it would not authorize LSEs to pay any price to acquire the necessary capacity. The CAISO believes the Commission must now turn its attention to the matter of what price is just and reasonable for the procurement of RA resources. The quantity of capacity required in the local areas is, in many cases, very near the total amount available. While this requirement does not inevitably result in the exercise of market power by sellers of local capacity, it creates conditions for its exercise. Of equally concern is that this condition creates the opportunity for LSEs to seek to avoid the costs of meeting an RA requirement by asking the Commission for waiver from the RA procurement based on a claim of sellers' market power. Without a clear understanding of the Commission's view of the procurement price or formula for evaluating what constitutes a just and reasonable price, parties may expect the CAISO to step in and make significant procurement under its "backstop" role. Such an outcome is not in keeping with the Commission's desire that LSEs are performing the majority of RA procurement and the CAISO role is very minor.

Consistent with the Commission's desire to minimize the CAISO's procurement role, FERC is also not likely to support the notion of the CAISO engaging in significant RA procurement. Therefore, the Commission should provide further guidance in this order and/or consider an immediate proceeding to establish the just and reasonable price that LSEs should be allowed. This, along with a compliance program, will facilitate LSE procurement.

3.B.3. CAISO Replacement Of Its Current "Must Offer" Process With A New System To Support Obligation For Resource Adequacy Resources

13. *The CPUC, CAISO and FERC must coordinate efforts in determining the replacement requirements, and the schedule for elimination of, the CAISO's existing "must offer" authority.*

See answer to 2.A.2.2 above.

3.B.4. CAISO Development Of A Resource-Specific Qualifying Listing And Testing Process

15. *The CAISO must determine whether it is prepared to undertake these activities and respond to the CPUC in its comments on this report.*

Like many topics addressed by the Report, the characteristics of a testing process to determine qualifying capacity evolves from the near-term to the durable RA end-state. The CAISO believes that the end-state must include provisions qualifying eligible capacity based on performance and/or availability standards that reward those suppliers that maintain and operate their resources in an efficient manner. In D.04-10-035, the Commission agreed and included this topic in the "second generation" phase. Whether the performance standards calculate "unforced capacity," as does the NYISO, or utilize specific availability criteria, as proposed by the NEISO, or some other variant, the need to test and/or compile additional operating data to determine eligible capacity must be accommodated. The CAISO accepts that it is likely the appropriate entity to administer the performance standards and it is committed to ensuring that this enhancement to the RAR is realized.

Consistent with the adoption of performance metrics, the Report expects that "testing [will] eventually be a part of this resource-specific qualifying capacity determination." D.04-10-035 adopted resource-specific formulas for determining qualified capacity. Many of the formulas rely on the NERC GADS definition of Net Dependable Capacity ("NDC"), which is the maximum capacity of a unit modified for seasonal limitations over a specified period of time less the unit capability utilized for the unit's station service or auxiliaries. Testing constitutes the means of ascertaining NDC. Nevertheless, the Report pragmatically recognizes that RA-specific testing protocols cannot be reasonably put in place and performed prior to the time the LSEs must procure and demonstrate RA compliance for June 2006.

In the near-term and prior to implementation of the durable RA program employing performance standards, the CAISO recommends using reported values to set the qualifying capacity of a specific resource. The value should not change during the interim period prior to implementation of performance standards in order to promote clarity in procurement.[9] This is true despite the fact that the NDC for thermal units will vary by month because of changes in ambient air temperature.[10] The NYISO, for instance, addresses this issue by creating a Summer Capability Period and a Winter Capability Period for which separate testing must be conducted. (See, NYISO Manual § 4.2.) Two points emerge from this reality. First, absent formal testing, it is unclear whether or to what extent a reported value benefits supply or load (i.e., a reported summer value may understate a combustion turbines winter capacity value). Second, it also highlights the complexity created by establishing the monthly RA obligation on the peak for each month.

The CAISO already has much of the necessary reported information. As part of the construction of the CAISO deliverability baseline analysis, the CAISO requested all

[9] It should be noted that under the CAISO's deliverability proposal, all existing resources will be deemed deliverable based on the anticipation that identified constraints will be relieved by the participating transmission owners through there upcoming transmission expansion plans.

[10] As noted above, NDC incorporates seasonal limitations resulting from the effect of changes in ambient air temperatures, which affect the operating capability of thermal units. As a general matter, the output of a combustion turbine is related to the ambient air temperature in which the unit is operating. For example, a combustion turbine will have a lower net output the hotter the ambient air temperature.

suppliers provide its qualifying capacity based on the formulas set forth in D.04-10-035 and assuming a one in two summer weather conditions. The CAISO received values for approximately 70% of the units in its Control Area. For those units that did not submit values, the CAISO inserted the capacity value included in its Master File in order to complete the baseline analysis. The Master File data, while sufficient for determining deliverability, may reflect a value greater than RA qualifying capacity in some instances because it does not take seasonal limitations into consideration as does NDC.[11] Therefore, the CAISO proposes that the Commission, in its Phase 2 order, specify that a unit cannot be considered a capacity resource unless it submits its qualified capacity value to the CAISO. This requirement will be deemed satisfied by the prior submission in response to the deliverability study. Others will have to submit values with documentation validating its conclusion. The CAISO does not believe qualifying capacity constitutes confidential or proprietary information and that it should, and can, be posted shortly after the Phase 2 order.

4.A.1. Focus For Load Serving Entities' Load Forecasting Efforts

17. The Commission should reaffirm the requirement that LSEs prepare and submit hourly load forecasts based on the "best estimates" approach.

The CAISO agrees that LSEs should prepare and submit hourly forecasts during the transition to a durable RA capacity-market end-state. However, as noted above, the CAISO objected to adoption of a "best estimates" approach to LSE load forecasting in Phase 1 on the basis that it added complexity to the CEC's forecasting effort and afforded greater opportunity for abuse and inaccuracy than the current customer approach. Admittedly, many of the concerns regarding the best estimate approach are likely to be muted in the near term by the current limitations on direct access and the requirements for commencement of service by CCAs, both of which restrict the potential for substantial, unanticipated migration of load among LSEs. As such, the CAISO can accept the best estimates approach, so long as the Commission restricts its endorsement of this forecasting method to the interim implementation period and that the appropriate forecasting approach will be revisited during the evaluation and development process for a capacity market.

The provisional nature of the best estimate approach is consistent with D.04-10-035's justification for its adoption. The decision selected the best estimate approach on the ground that "resource adequacy commitments [should] be made in the context of the LSE's own procurement efforts, and not some separate side requirement that does not connect to the realities of procurement." As noted by President Peevey in his ACR, an organized capacity market will provide LSEs with a means of addressing load migration. The monthly auctions conducted under the eastern ISO models allow LSEs to utilize the

[11] The Master File data corresponds to a unit's "PMAX." The unit PMAX values identify the upper limit on the quantity of energy and capacity that can be bid in CAISO and correspond to the "nameplate" rating of the units. "Nameplate" typically refers to the rated capability of the unit that is shown on a "nameplate" attached to the unit and reflects the capability of the unit under optimal operating conditions, not high temperature conditions.

current customer approach to accurately and efficiently procure their capacity obligations. Thus, the Commission's durable RAR should also envision the use of the current customer load forecasting approach.

4.B. Coincidence Adjustment Methodology

18. *The Commission needs to choose from among two broad approaches to load forecast coincidence adjustments*:

    Methods using historic data, perhaps from one or more years, that can be implemented by LSEs as part of the preparation of preliminary load forecasts,

Coincidence adjustments that utilize LSE-specific preliminary hourly load forecasts constitute a better fit with the "best estimate" load forecast approach. Weighting/coincidence of past historical peaks can exhibit distinct differences (in geography and weather pattern) from future peaks. Nonetheless, like the "best estimate" forecast approach, the derived coincidence should be reality-checked against historic performance. Due to the inherent uncertainty and inaccuracy in year-ahead forecasting, the determination of coincidence should avoid using the synchronized summation of individual LSE's hourly forecasts. Rather, a theoretical/generic peak load pattern should be developed for each month; for example, a composite (non-coincident) peak pattern compiled from each LSE's highest peak hour (i.e., 16:00) load value for that month.

4.C.1. Allocation Of Impacts To Load Serving Entities

19. *The Commission needs to interpret the Topic 3-4 Working Proposal carefully as outlined in Appendix C and confirm those portions that fit within the framework previously established in D.04-10-035, and reject those portions that do not.*

The CAISO supports the proposal to treat dispatchable DR programs as resources since the relief expected from these resources would be known in real-time and would be dispatchable. For EE programs, the CAISO supports using the percentage of total IOU retail sales to determine an LSE's share of that utility's incremental EE impact. The CAISO also supports updating these percentages annually. Finally, the CAISO supports the percentage of each LSE's sale to the sum of all LSEs' sales within a utility's service area to allocate that utility's DR impact. These percentages should also be updated annually.

4.C.2. Preparation Of Monthly And Hourly Impacts

20. *The Commission should direct EE, DR, and DG measurement and evaluation efforts to support the hourly load shape impact assessments that are necessary to the inclusion of the impacts of policy-preferred resources within RAR.*

A majority of the EE and DR programs are within the SCE and PG&E service areas and, therefore, both PG&E and SCE have historical data to determine the actual curtailment expected when these programs are initiated. In the long term, the CAISO would prefer only crediting LSEs sponsoring DR and EE programs. However, in the interim due to the cost and complexity of adequately allocating credits to specific LSEs sponsoring these programs, the CAISO supports the PG&E and SCE approach to allocate incremental impacts among all LSEs on a pro rata basis.

4.C.3. Responsibility To Quantify Effects Of Energy Efficiency, Demand Response, And Distributed Generation

22. *The Commission should require IOUs and any independent evaluators to prepare EE, DR, or DG impacts according to the informational needs of RAR.*

The three IOUs keep track of active participation in each of the EE, DR and DG programs within their respective service areas. In addition, the three IOUs are the repositories of historical information and are familiar with the expected response of each of these programs when called upon. Thus, the CAISO supports the recommendation that IOUs and applicable independent evaluators preparing EE, DR and DG impacts to provide the information to the CEC for review and adjustment.

4.D. Quantification & Allocation Of Distributed Generation Impacts To Load Serving Entities

23. *The Commission must determine whether a simple DG impact assessment methodology is acceptable for this round of RAR compliance, and that developing more sophisticated methodologies can be deferred to subsequent cycles.*

For this round of RAR, the CAISO supports an approach that is transparent, equitable, and relatively easy to quantify and apply.

4.E.1. Transmission & Unaccounted For Energy Estimates

24. *The Commission must decide whether the simple transmission losses and UFE method proposed by the CAISO is acceptable.*

The CAISO supports the method it proposed during the Phase 2 workshops.

5.A.3.6. Are We Heading In The Right Direction? What Are The Differences In Effects On Future Investment?

27. *The Commission needs to determine whether to adopt a "Bottom-up" or "Top-down" approach. Parties are encouraged to further detail the differences in grid operation and implementation between the two approaches.*

On balance, the CAISO supports the top-down ("TD") approach. The TD approach is more amendable to integration of a single standard capacity product. The bottom-up ("BU") approach, in contrast, is inherently hostile to a uniform product because it follows an LSE's load duration curve specifically to create time differentiated capacity products. Consequently, under the TD approach, as existing products expire and must be replaced by a conforming capacity product, the LSE's portfolio will transition toward reliance on the standard product to be traded in the centralized market. The conversion to a standard product following the BU would necessarily be more abrupt. However, the CAISO notes that if an "after-the-fact" compliance program is adopted, the BU approach is likely to be more amenable.

Further, as noted in the CAISO's prior comments, the principle difference between the "pure" TD and the BU proposals is the sources for establishing the parameters of the resource's obligation. In the TD, the resource is obligated by rule, incorporated into RA agreements or through the CAISO tariff, to offer for all hours it is physically capable of running consistent with environmental or other regulatory limitations. In contrast, the BU resources are limited only by their physical and regulatory limitations, but also by contractual offer periods, such as 24hrs, 16 hrs, 8 hrs. This creates a possible impact on the CAISO's ability to optimize resources. The CAISO dispatches resources on the basis of system efficiency and conditions. To the extent the pool of resources is limited by an LSE's selection of its portfolio based on LSE expected load characteristics, inefficiencies and potential operational issues may be introduced during the CAISO's efforts to optimize resource dispatch on a system-wide basis. However, the TD approach will also be subject to this inefficiency if existing contractual arrangements are deemed eligible to satisfy the RA obligation during a transition period. However, this issue remains over the longer-term with the BU approach, but diminishes under the TD approach as LSEs transition to a standard capacity product, as described above.

The BU proponents contend that the BU counting rules prevent LSEs from relying too heavily on energy-limited resources so as to ensure that each LSE's portfolio can meet that LSE's energy requirements as well as capacity obligations. This is claimed to be a disadvantage of the TD. However, it has been pointed out that high load periods can occur during off-peak times, especially Sundays. Such time period would be identified on the BU LSE load duration curve as likely being satisfied by a peaking resource, i.e. 6 x 16 or 5 x 8. Yet, due to contractual limitations, the resource would not, in fact, be available to the corresponding point on the load duration curve. Thus, the CAISO has strongly advocated that an off-peak BU analysis must be implemented as a precondition to the CAISO's support of a BU approach.

Nevertheless, it is true that if existing (contract based) resources are eligible to satisfy a TD approach, the same energy deficiency concern exists because the collective set of resources offered to meet the peak hour may not include any off-peak resources. The TD approach prepared on behalf of Mirant, attempts to address this problem by providing that an LSE cannot include more than the "maximum cumulative contribution" ("MCC") of specified resource categories, which are based on physical and contractual availability limitations. (See, Exhibit 1 to "Top Down" Alternative to Joint Parties Proposal for Load Forecast and Year/Month Ahead Showing that Supports an All Hours RAR ("TD Proposal").) Therefore, from an energy perspective, the two approaches employ similar remedial concepts to ensure that the energy sufficiency will be provided in all hours.

Further, it is not clear that any great difference exists between the TD and BU approaches with regard to the implementation. Previously, the Joint Parties argue that the TD approach will require considerable effort to define the exceptions for RAR resources. Both the BU and TD will require implementation of "use-plans" for use-limited resources, the particulars of which are currently being developed in the CAISO's MRTU process. Intermittent resources, i.e., solar or wind, can be accommodated through the CAISO's Participating Intermittent Resource Program ("PIRP"). In brief, so long as the resource schedules in accordance with CAISO provided forecasts, it would be deemed available and having met its offer obligation. As such, the CAISO believes that the universe of resources requiring this type of "exceptions" analysis is relatively small.

5.B. Dispatch Authority For Demand Response Programs

28. *There are two issues the CPUC must consider in how it includes Demand Response programs within the RAR framework. First, is it appropriate to plan to use dispatchable DR programs up to the limits now established for each tariff and/or program? Second, once DR programs are put forward as qualifying capacity as part of the compliance filings of each LSE, how do these programs actually get triggered should the LSE or the CAISO decide that they are needed?*

Consistent with D.04-10-035, dispatchable loads should be classified as resources. The Report correctly notes that counting certain DR programs may be inconsistent with the goal of RA to marshal sufficient resources to "avoid" emergencies and load interruptions. This is particularly true for those current interruptible programs, such as the Schedule I-6 rate, that are relied upon by the CAISO to provide short-term responses to emergency conditions. DR resources that are dispatchable for emergency use only conflict with the objectives of RA and should not be used in RA accounting.

However, D.04-35-10 appeared to articulate a compromise position by imposing a limit on the quantity of 2-hour DR programs that can count toward an LSE's RA obligation of .89% of monthly peak. (D.04-10-035 at 27.) It is unclear whether this statement was intended to encompass DR programs triggered solely by emergency conditions. If so, the CAISO agrees with the Report that the RA process avoid counting rules that dampen the effectiveness of RA to signal additional investment in infrastructure necessary to maintain reliability in the first instance. Accordingly, the CAISO believes the Commission should further clarify a "loading order" that requires an LSE relying on DR to meet its RA obligation to initially offer programs that are not triggered solely by a declared emergency. [12]

Moreover, at least during the transition period and possibly longer depending on the nature of the dispatchable load programs and effectiveness, dispatchable loads should be

[12] It also should be recognized that many DR programs, such as air-conditioning cycling initiatives, which are extremely effective and valuable in the peak summer months provide significantly less load relief during the off-peak months. The ability to capture the seasonal variability in the counting protocols for the initial June 2006 showing is likely to be impractical.

restricted to satisfying an LSE's system, not local, RA requirements. Dispatchable programs are not guaranteed to be available when called upon at their full value based on a variety of business needs. Customers in dispatchable programs do not have load curtailment as their primary function and, therefore, it is not prudent to count on using these resources, in the initial instance, for local needs or up to the tariff limit for system purposes. The CAISO defers to the CEC and IOUs to determine an appropriate measure for estimating the load reduction from DR programs.

Apart from the foregoing limitations, dispatchable DR should have a similar qualification to be available for CAISO dispatch (be it directly or through the LSE) in full compliance with their tariff provisions. The costs of dispatchable DR programs are borne by ratepayers. Ratepayers should obtain the benefit of this bargain by being able to utilize the resource to optimize the electrical system in a manner consistent with the terms of the agreement reflected in the program tariff. In this regard, DR programs must be designed primarily to elicit customer response and participation and secondarily to conform to RA conventions. However, for RA purposes, the different types of demand response programs can be broadly grouped into two categories: (1) those that need curtailment decisions day-ahead (e.g., need to know if they should shut down one of the factory mills for tomorrow), (2) those that can handle curtailment decisions within the Hour-Ahead/Hour-Ahead Scheduling Process ("HASP") or real-time. Compared to RA generation resources, the first category would be similar to long start units, and the second category similar to short-start units (or units able to provide non-spinning reserve from cold start). Both categories can be subject to must offer, i.e., made available to the CAISO by submitting a schedule or bid. The first category would sell only in DA (be paid not to consume tomorrow); the second category could sell A/S DA (non-spin) and energy in RT if dispatched (to curtail). So, unless a DR program is prohibited to act in one of these ways, it should count towards RA by meeting the must-offer obligation in the manner defined above. Some demand programs may have use limits, similar to RA generation programs, which should not conflict with RA use limits. In other words, except for the use limit no additional conditions should be attached. If a DR is able to sell non-spin, it can attach a Contingency Flag to the sale, and be assured that it would not be dispatched unless there is a contingency condition. In that case it would count as RA. However, if the DR is not responsive as non-spin (or a slow operating reserve that the CAISO may define), and the DR resources does not want to be curtailed except under emergency, the CAISO believes such resource should not be counted as RA in the future.

5.B.1. Planning To Use Demand Response Program Capability As Qualifying Capacity

29. The Commission needs to resolve a series of questions that such a use-limited program raises:

• *Is a call capability limited to at most 4 days per summer month enough to say that this resource can be counted as qualifying capacity for each of the four months?*

The LSE must submit an acceptable usage plan similar to that stipulated for other use limited generation resources. The LSE should be given the opportunity to justify the number of days for each summer month for these programs. Therefore, if they would like to use the program for energy reasons more in August than June, the LSE should be able to justify the reason. However, in order to avoid undue reliance on capacity that is insufficient to meet system needs, the quantity of such limited capacity should be restricted to a certain percentage of peak load perhaps using a similar method reflected in appendix G of the Phase 1 workshop report. Given that the level of DR for summer 2006 is likely to remain reasonably static from its current level, the limits on such programs as qualifying capacity can be established at a later date.

• *If four days per month is too few, then what is the minimum number of days that allows this DR program to be considered sufficiently flexible to serve as reserve?*

The CAISO is very concerned that a program providing only 4 days in a month is potentially not enough. However, this concern can be mitigated by limiting the magnitude of DR capacity. The CAISO believes this topic warrants further discussion.

• *Should DR programs with triggering conditions requiring CAISO emergency conditions be excluded as ineligible to be considered resource adequate, e.g. are there some dispatchable DR programs that should not be counted upon as a resource for resource adequacy, but held in reserve for true emergencies? If so, what level of capacity should be held back?*

See above.

• *What mechanism should be used to decide which programs should be retained for true emergencies and which ones should be modified for more regular use in a resource adequacy framework?*

See above.

• *For those programs for which it is acceptable to convert to use in resource adequacy, should the triggering conditions of these programs be modified to allow DR to be scheduled through the CAISO on a Day Ahead basis?*

The CAISO should be aware of the quantity and location of the DR programs and should have the ability to dispatch, but it is not necessary to have a day-ahead schedule.

• *Should DR programs be exempted from the Day Ahead scheduling requirement, but be made available to the CAISO in some other way if system conditions warrant their use?*

See above.

5.B.2. CAISO Triggering Of Dispatchable Demand Response Programs

The issue at hand is to determine how compatible dispatchable DR programs are with the *dispatch and bidding protocols for non-DR resources.*

31. The Commission needs to resolve the following questions:

• What are the system conditions under which the CAISO is allowed to exercise its "system support rights" for DR nominated as resource adequacy resources by LSEs? Alternatively, are there supply/demand conditions for the IOU service areas that are the appropriate basis for triggering demand response programs designed for that service area alone?

Demand Response programs can and will play an important role in Resource Adequacy. The IOUs are fortunate to have various DR programs that offer an opportunity to be used to meet the IOUs RA requirements. The CAISO and the CPUC should continue to work with the IOUs to determine acceptable triggering mechanisms for DR programs that are qualified to be used for the RA requirement. Due to the diverse programs offered by the IOUs today, these programs should be re-evaluated and acceptable triggering mechanisms should be designed in these programs for 2007 and beyond (if acceptable triggers can not be created, then these programs will not be able to be qualified under the RA requirements). The IOUs should be allowed to implement the acceptable programs based on the agreed upon triggers. The CAISO should maintain the ability to trigger (or cause to trigger) the Emergency DR programs which as stated above, should not count for the RA requirements.

• Are these conditions the same as those for more flexible generation or energy limited generation?

No, the conditions are not the same. Most parties, including the CAISO, operate under the presumption that DR is the last in the stack of RA resources. To be clear, these are the DR resources that are not "participating load" and therefore reflecting their price for interruption with market bids. Rather, these are the load interruption programs that the Commission has designed under a specific set of assumptions and the costs are reflected in a specialized tariff.

• If they are not the same, are they more restrictive, essentially creating some sort of queue for resources in which DR resources come last?

See above.

• If there is some sort of queuing, is there a hierarchy among the various dispatchable DR programs?

The IOUs should clearly have a hierarchy determined for their DR programs. Because the programs may be different for each of the IOU territories, it should be IOU specific.

5.C.1. The CAISO Methodology For Determining Import Capability

We ask the CAISO to outline the specific process in its comments to this report.

A few stakeholders raised a concern that an import schedule value for a particular Branch Group could be abnormally low due to an anomalous condition occurring during one of the four peak hours selected to assess import deliverability. In order to address this concern, the CAISO applied the following screening test to identify significantly abnormal data for a particular Branch Group. The specific process for adjusting the import levels would be similar to the process described below.

Two tests were performed on the Branch Group data to screen for significantly abnormal results. The first test was applied to all Branch Groups and application of the second test was restricted to those Branch Groups identified by the first test. The first test calculates the average and Standard Deviation for each set of Branch Group data. If the minimum Scheduled Net Interchange value for a Branch Group deviated significantly from the average value for that Branch Group, then the second test was applied to that Branch Group. It was assumed that the data fit a normal distribution and that 95% of the samples should be within 2 Standard Deviations of the average. Therefore, a significant deviation from the average would be at least two Standard Deviations. However, because of the small number of samples a less restrictive test was applied, and a significant deviation from the average was assumed to be a deviation of more than 1.3 Standard Deviations from the average (80% of the samples should be within 1.3 Standard Deviations of the Average).

If a significant deviation is observed following the first test, the second test is run that calculates the average Scheduled Net Interchange over a larger sample size representing the peak period. If the average is larger than value for the sample peak days, the average is adopted. If the peak days value exceeds the average, no adjustment is made.

For example, after applying the first test to each Branch Group, BLYTHE_BG, CFE_BG, and IID-SCE_BG were each flagged for further analysis. For these three identified Branch Groups, the average value among the hour 17 Scheduled Net Interchange (peak hour) values was calculated between July 1, and September 16 2004. The average value over this larger sample of hours was less than the originally proposed value for the BLYTHE_BG and the CFE_BG, so no adjustments were made to these Branch Groups. However, for the IID-SCE_BG the average over the larger sample of hours was 42 MW higher and, therefore,increased from 330 MW to 372 MW for this Branch Group. The Allocatable Import MW was also slightly increased from 330 MW to 372 MW for this Branch Group.

In addition, the CAISO will request that all LSEs provide contract information regarding imports into the CAISO Control Area for consideration in the path-by-path study. It is expected that this contract information will be embodied in the historical information used in the study. A few exceptions could exist because of the netting of imports and exports in the historical data. For identified exceptions, the CAISO may need to adjust the import levels on certain paths and redo the analysis.

5.C.2. Allocation Of Import Levels Among Load Serving Entities

Parties are encouraged to include a discussion of the option 3 in their report comments.

A detailed description of option 3 was provided, entitled Accounting Credits for Import Capacity (ACIC). This option appears to algebraically add the Branch Group Import capabilities determined by the CAISO to be deliverable into a Total Control Area import capability and then allocate this amount to LSEs. LSEs can then request to use their allocated amount on any Branch Group. Because this approach could result in the total allocation on a particular Branch Group being overprescribed and undeliverable, this option requires the CAISO to perform an additional assessment on the desired allocations to determine deliverability. In this regard, the desired import amounts could be distributed across the various Branch Groups in a way that is inconsistent with historical usage and, therefore, has not been previously determined to be within the reliable operating region. Therefore, the CAISO Deliverability analysis would need to include stability and post-transient analysis in addition to the thermal Deliverability analysis described in the Deliverability Methodology. Furthermore, an additional powerflow base case, which explicitly models unit commitment levels, would need to be developed to perform this stability and post-transient analysis. Thus, while it is technically possible for greater quantities of import capacity, CAISO does not propose to perform this analysis because it cannot be accomplished in a timely manner that allows LSE procurement and showing prior to June 2006.

5.C.2.2. Evergreen Priority For Existing Commitments

The Commission will be able to make a more informed determination on this issue if Edison provides that information in its workshop report comments.

The CAISO's long-term proposal for modifying import capacity relies on giving evergreen priority to existing commitments.

5.C.2.3. Import Capability Allocation For DWR Contracts

In the comments on the workshop report, parties should address how the deliverable portion of the contracts can or will be determined.

The CAISO supports SCE's proposal to use the contracts historical delivery to assess the path on which contract will most likely be delivered.

5.C.2.5. "Use It Or Lose It" Provisions

36. *Parties in their workshop comments should address whether the FPL/SCE alternative proposal for allocating based on share of peak load may resolve the needs for 'use it or lose it' provisions and the need for a secondary market for import shares.*

37. The Commission must decide if it wants to have an evergreen provision for existing external resources that may count towards the RAR. If so, which resources are eligible, physical resources and/or contracts? If the Commission decides against an evergreen provision, then it must establish a means for selling and trading un-used allocations among LSEs and whether there should be a "use it or lose it" provision. Based on the workshop comments, the Commission will have to determine whether the FPL/SCE alternative proposal is a superior approach to the approach whereby the allocation would occur based on TAC contribution and how that approach addresses the outstanding issues outlined above.

During the May 9, 2005 Deliverability stakeholder meeting, stakeholders commented that there is a need to identify new import levels that go beyond the historical import levels that were preliminarily found to be deliverable. The CAISO acknowledges that a mechanism is needed to modify the import deliverability levels going forward and such a mechanism may indeed increase the total import capacity beyond the initial levels for the introduction of resource adequacy. The development of a long-run import capacity methodology should be achieved through discussion with stakeholders because there will be many factors to consider and balance. For example: stakeholders have proposed that the CAISO conduct a sensitivity analysis prior to the implementation of resource adequacy in June 2006. Yet, the number of "sensitivities" is practically unlimited and would require time consuming stability and post-transient analyses in addition to the thermal loading analysis addressed by the baseline study tools. In addition, this type of analysis will involve an interplay with existing, and new, generation resources. It is essential that any new levels do not impact the deliverability of existing generation. Further, any changes would undermine the import assumptions the CAISO is using to perform the Phase II deliverability study that is intended to establish the deliverability of all proposed new generation to be operational after summer 2006. Finally, the CAISO believes that it would be in conflict with FERC Policy to assume a level of imports in the Deliverability Assessments that have not been used historically or do not have firm plans to be used in the future. In sum, CAISO initially used historical values to establish import levels that can be used for the introduction RA but supports moving to a more appropriate level setting methodology such as a contract basis for future Import capacity. Thus, the CPUC should add this issue to the list of topics for future RA phases.

5.C.3. Deliverability Of Resources In Generation Pockets

Parties should comment on the options above in their comments to this report.

The Report captures the principle conclusions of the CAISO's preliminary deliverability results and recommendation that existing units and imports be deemed deliverable so long as the participating transmission owners agree to complete those transmission upgrades identified by the CAISO to relieve the majority of the constraints. The CAISO Deliverability studies for imports and Generation pockets identified approximately 2300 MWs of resources that would be derated if certain transmission projects are not undertaken. The Report correctly notes that of the 933 MW of undeliverable capacity in PG&E's service territory, all but 10 MW can be resolved by transmission upgrades identified by PG&E, but not yet incorporated into its annual CAISO grid expansion plan. All but approximately 170 MW of SCE's 1100 MW of undeliverable capacity can also be relieved through relatively minor, and therefore likely cost effective, transmission or operational solutions. Given the current stage of the CAISO's annual grid planning process, it is unlikely that the transmission solutions can be included in the PTOs' 2006 grid expansion plan. Accordingly, the CAISO would recommend that the proposal to consider existing resources deliverable be contingent on the transmission upgrades being complete by June 1, 2008. It would also be appropriate for the CAISO to perform economic evaluations of potential transmission solutions for the remaining MW (i.e., 10 in PG&E, 170 in SCE, and 160 in SDG&E). For these remaining undeliverable suppliers, if the upgrades are not identified as economic and therefore justified for IOU construction or, alternatively, funded by the impacted suppliers, the qualifying capacity of those resources must be lowered to account for the lack of deliverability. The Large Generator Interconnection Procedures added to the CAISO Tariff on July 1, 2005 requires that an assessment of deliverability of new generators be performed in a manner that is consistent with how existing generators were assessed. Failing to lower the qualifying capacity of existing undeliverable generation on a long-term basis could prohibit the CAISO from limiting the deliverability of transmission constrained new generation projects for resource adequacy counting purposes. In the absence of a mechanism for reducing deliverability of constrained new generation, new generation developers may have insufficient incentive to sponsor necessary transmission upgrades.

The allocation of economic benefits among market segments from this simplifying assumption is uncertain without more detailed analysis. On the one hand, LSEs are likely to benefit from reliance on existing resources without having to augment their RA procurement to compensate for deliverability based derates of existing capacity. This is most notable for those undeliverable MW located within load pockets. On the other hand, suppliers will benefit from higher qualifying capacity without the cost responsibility to achieve these higher levels. This applies for suppliers that will benefit from the transmission solutions as well as those that do not have identified solutions to the constraints.

Alternatively, the Commission may elect to enforce the identified derates immediately. If so, both PTOs and suppliers will have the incentives to make the cost effective transmission upgrades and thus remove those derates that are most valuable for RA capacity. The CAISO notes that if the Commission rejects the CAISO's primary recommendation and elects this alternative approach, then it must determine a method to allocate the derates across the appropriate generation resources. In this case, the CAISO recommends a pro rate allocation of de-rates to suppliers in constrained generation pockets. The Commission should utilize the distribution or effectiveness factors of the units as described in the Generation Deliverability Straw-Person Proposal. Ignoring these factors could result in an inefficient allocation and thus a much larger amount of generation requiring a de-rate.

5.D.1. Existing Liquidated Damages Contracts & Transition Period

39. The Commission needs to decide whether (and to what extent) to grandfather existing LD contracts and allow them to count for resource adequacy. The Commission needs to determine how it will transition existing LD contracts into a RAR framework.

The Commission must move decisively to remove LD contracts from the world of resource adequacy. The fundamental purpose of RA is to evoke a forward planning an procurement process that seeks to ensure sufficient resources (adequacy) exist to serve California loads in the real-time (security). However, the very nature of LD contracts are to allow the seller to determine whether it is in its financial interest to actually provide energy under the contract or relay upon the CAISO markets to have sufficient supply to serve the load. Under these circumstances, it is not clear how resources will recover the necessary fixed costs to ensure they remain available to serve California. To address these issues the Commission has already defined the end-state as that which is capacity based. This ensures that RA resources are physical, verifiable, and deliverable to California loads. These principles cannot be assured prior to the real-time provision of reliable electric service if the Commission, working in concert with the CAISO, cannot determine the quantity of committed infrastructure, and whether these assets can be delivered to California.

That said, the CAISO understands that grandfathering existing LD contracts may be a necessary and expedient requirement. As noted above, this assumes some level of grandfathering of LD contracts.

40. The Commission needs to decide if it will permit new LD contracts to count for resource adequacy and to determine if an appropriate "grace period" should be adopted to allow the market to develop a proper capacity product

There is no need to enter into new LDs. The Commission must adopt a capacity product definition or fundamental elements. The CAISO is confident that the market will respond very quickly once this issue is decided. The introduction of the SVMG proposal is clear evidence that the market forces are already at work to respond to the new procurement paradigm. The Commission should recognize that LSEs are only required to show 90% procurement in the year-ahead report. Thus, they have many months between the Commission decision and the need to show 100% procurement. Comments by the workshop participants clearly indicated that a 90 -120 day period is sufficient to develop the new capacity based products.

41. The Commission needs to decide if it would permit waiver requests for an LSE to not meet its RAR. If the Commission determines that it would adopt a waiver, the Commission would need to establish the criteria under which a waiver request would apply. In comments, parties are asked to identify and propose the criteria the Commission may use if it chooses to adopt a waiver.

Waivers are unnecessary. The Commission is already providing great deference to LSEs with the allowance for LDs to count. To the extent that some LSEs (ESPs) claim they are unable to make the necessary procurement, then the Commission should consider the proposal wherein the IOUs will perform the full procurement and charge the LSEs within their service territory for the appropriate pro-rata costs. The Commission must be cautious about waivers of any kind because these will reduce the PRM on a one for one basis. For example: if an ESP requests an waiver for 50 MW in the San Francisco Bay Area, then the PRM will be reduced by that full measure, including approximately 1% of the local area requirement.

5.E. Imports

Since the issues raised by Powerex were not fully discussed in workshops, parties are encouraged to discuss the proposal in the comments to this report.

43. *The Commission will need to determine how to address the role of imports in meeting the Resource Adequacy Requirement. In workshop comments, parties should specifically address whether there are special circumstances for imports that would require an exemption from the determinations made with regard to: 1) the availability, must-offer requirements, that internal generators are subject to; 2) the resource specific provisions that are the objection of the "endstate'; and 3) which import products constitute capacity as opposed to energy.*

Imports are not uniform. The treatment of imports will differ depending on whether the import is resource contingent with dynamic scheduling capabilities or an import that is not dispatchable in real-time (intra-hour).

The first group (dynamically scheduled imports) should be treated like internal resources with respect to availability/must offer, and resource specificity, but not for deliverability. Eligibility for RA (sale of RA capacity) should be contingent upon a showing of ability to secure transmission in the intervening control areas. Similar to the Phase 1 order, this requires that the resource obtain transmission for the operating hours that cannot be curtailed for economic reasons or bumped by higher priority transmission.

With respect to the second group, the CAISO would prefer, as stated in Phase 1, that the non-dispatchable import be from a control area that agrees not to curtail delivery of the resource under scarcity conditions in the control area or the seller's native load. This is the typical practice in the eastern ISO capacity markets. (NYISO Manual § 4.10.) Nevertheless, the CAISO conceded in Phase 1 that under current market conditions, this arrangement was impractical such that the characteristics set forth in 5.E.1 reflect the appropriate counting rules for system imports. Moreover, there would be no resource specificity requirement beyond identifying the import scheduling point and the LSE must have sufficient allocation of capacity at the import scheduling point to satisfy deliverability requirements. What constitutes acceptable import "capacity" should be revisited during the process of defining the durable capacity market construct.

Contrary to the position taken by Powerex, the CAISO urges that the must offer obligation and waiver processes apply to non-dispatchable imports. Since these are not physical resources, an issue to be resolved is whether such "resources" are treated like short start units (with must offer obligation continuing until the pre-dispatch time frame) or if they can define their own minimum run time or start up time so that they may have to be committed (or receive a waiver) far in advance of real time. The CAISO prefers not to allow such resources to define their own minimum run time or start up, unless the import is "resource contingent", and they have filed the resource's characteristics with us (in our Master File). For example, if the import is (1) dynamically scheduled AND (2) the dynamic schedule is tied to a specific resource, they can submit that resource's technical characteristics (including start up time, minimum run time, etc. for inclusion in our Master File). In that case, if the resource is long start, the unit's start up and minimum run time define the import's start up and minimum run time, along with must-offer waiver privileges of long start units. Otherwise, "amorphous" imports should be treated like short start units.

The RA product could be either capacity or energy. If sold as capacity, it must still submit energy and/or Ancillary Services bids in the forward market unless granted a waiver.

5.F. Allocation Of DWR Contracts And Utility-Retained Generation, Including QF Contracts, To Non-Utility Load Serving Entities

"The Commission must decide whether any portion of the capacity value of the DWR contracts, QF contracts, and utility retained generation should be allocated to non-utility LSEs."

Any such allocation must not create barriers that might prevent these resources from being scheduled by LSEs and/or dispatched by the CAISO to meet reliability requirements. Such a barrier resulted, for example, from assignment to SDG&E of the unit dispatchable contracts for Alamitos 5 and 6. These units were frequently not needed to meet SDG&E load and, therefore, not dispatched despite their potential effectiveness at meeting reliability needs in SCE's service territory.

5.F.3. Allocation Issues For CPUC Decision

If the Commission decides this question in the affirmative, it must choose a method or methods for making such allocations. The general consensus reached at the February 8, 2005 workshop is that the issues raised in connection with Topic 16 can be resolved by the Commission on the basis of comments and replies submitted in response to this workshop report.

See above at 5.F.1.

5.G. Wind And Solar Resources Without Dispatchable Backup

45. *The CPUC must establish a process for assessing generator capacity that will be used by LSEs to meet their resource adequacy obligation.*

See below.

5.G.1. How Much History Should Be Used For The Analysis?

46. *The CPUC must decide whether a rolling three-year average of an individual month's generation is an appropriate historical benchmark for the next year's expected generation.*

The CAISO believes a three-year average provides an appropriate historical measure of a unit's expected future generation.

47. *The CPUC should establish a methodology for assessing generation capacity (and expected output) that does not unduly disadvantage renewable generation. One issue that should be examined closely is how to assess renewable generation assets that have been upgraded or repowered.*

Likewise, the CAISO cannot support a methodology that *over-estimates* peak-hour production from renewables, especially in light of current incentives to expand this generation sector over the next several years. We believe other considerations (such as a wider assumption of peak period hours) works to the advantage of wind generation, and possibly overstates its contribution at peak. For repowered sites that demonstrate significant improvement in available output, the historical average will begin reflecting these effects after the first year of performance.

5.G.2. What Hours Should Be Used For Evaluation Of The Peak Period?

48. *The Commission must decide whether the SO1 hours are an appropriate measure of the peak hours.*

The CAISO recognizes that while SO1 hours do not necessarily align with the hours of actual peak, these hours offer convenience/simplicity for many participants. Production from wind and solar resources can change dramatically across the afternoon hours. The wider window of SO1 hours gives a somewhat added boost to these resources. In the interest of closing this issue, the CAISO agrees to the SO1 hours of 12:00-6:00 for the summer months as the appropriate counting convention. However, the CAISO does not support an open-ended definition for the non-summer months. Therefore, if 12:00-6:00 is to be used, the CAISO recommends applying that period for all months of the year.

5.G.3. To What Degree Should Different Types Of Generators Be Measured Separately?

49. The Commission must decide whether generation should be calculated separately for each wind generation region.

Barring the recognition of individual site performance, the CAISO supports a regionally-based measure of wind units' performance.

5.H. Energy-Limited Resources

51. The Commission must decide whether both aspects of the qualifying rule for energy-limited resources should be applied in the non-summer months or, in the alternative, it is not necessary to mandate that qualifying capacity must be able to operate for as many hours in the month as demand is expected to be above 90% of the month's peak demand.

Energy limited resources are "energy limited" not "availability limited." Pursuant to rules developed by the CAISO in its MRTU process, such suppliers will submit an annual plan with monthly breakdown, with the latter being updated every month for the remaining going forward months while respecting the total annual quota requirement and use limitation. The monthly quota is then broken down to daily increments. These are all for energy limits, not capacity limits. Energy limited resources can (should be able to) provide Ancillary Services with a contingency flag to make sure they are dispatched only under contingency conditions. To the extent that the CAISO can forecast ample Ancillary Services capacity for the off-peak period, the CAISO may grant a waiver for energy-limited resources for limited durations. This means implicitly accepting as RA resources those resources that are not capable to produce enough energy to run for all hours, but qualify as Ancillary Service certified during some off peak months. To ensure there are not too many energy-limited resources of this type included as RA resources, a limit on the volume (total MW) of such resources and some priority order (e.g., first come first served) may need to be established taking into consideration the resource type and location. However, such effort may be deferred to future RA proceedings.

5.I. Commercial On-Line Dates For New Resources

52. The Commission must decide whether the CAISO-CEC working proposal for COD status is appropriate and satisfactory.

The CAISO supports the CAISO-CEC working proposal.

5.J.1.1. Timing Of CAISO Supplemental Procurement

53. Parties should include in their workshop report comments a discussion of how the 100% forward local capacity requirement impacts the month ahead reporting obligation. Given the compressed timeframe to implement RAR (local and otherwise), parties should also comment on how to work through the first year's *requirement. Parties are encouraged to propose options to meet the June 2006 requirement.*

The Commission should still require the first year-ahead report. This will provide value to all parties because it is the first of many such reports to be created on an ongoing basis. By doing so, the Commission will ensure LSEs are making the necessary forward procurement and it provides the Commission/CEC/CAISO an opportunity to implement and test the monitoring functions. The load forecasting and local procurement are likely to be the most in need of adjustment in this first year. In this regard, prior to adoption of a durable capacity market, perhaps with the inclusion of a demand-curve to establish pricing, the Commission should be prepared to deal with the problem of what is a "just and unreasonable" price and what steps the Commission will take if LSEs indicate they have encountered locational market power when trying to procure local capacity resources.

5.J.2. Reliability Criteria Within The Local Area

56. *The Commission must decide whether the more stringent load forecasting and outage conditions for identifying local capacity requirements in the CAISO proposal should be accepted.*

The objective of the reliability criteria within the local area is to identify the minimum capacity requirement for each identified local area while maximizing the utilization of area transmission facilities to access capacity external to the local area for local area reliability needs. To the extent that the local area transmission capability is insufficient to meet the local area reliability needs, local capacity will be needed to provide for operation of the CAISO Controlled Grid in accordance with applicable reliability standards. For purposes of the Study, the applicable reliability standards include both the CAISO's established planning and operating standards. The planning and operations criteria used in performing the study are consistent with NERC/WECC/CAISO planning standards, as they may be modified, and will address system performance levels A, B and C. In addition, the study methodology for determining the local area requirements conforms to any operations procedures specific to each local area as well as the methodology in the CAISO/PTO's regular planning studies. The CAISO's existing Planning Standards require each PTO to plan their systems to conform to the CAISO Planning Standards. In addition, CAISO Operations identifies additional requirements necessary to address certain operational contingencies required to meet real time reliability.

The CAISO has been using the RMR contracts and the must offer obligation over the past several years to operate the grid reliably to meet local area operational requirements and manage intra-zonal congestion. While it is the CAISO's intent and long-term objective to phase out RMR Generation, any such transition must be done prudently over an appropriate timeframe. In the event that additional capacity is required above the amount identified pursuant to the study and procured by the LSEs, the CAISO will have to procure the additional necessary capacity in a manner and timeframe as set forth elsewhere in these comments. It is, of course, the objective of the proposed Study methodology and criteria to determine LSE procurement requirements that will fully satisfy the CAISO's real-time operating needs under most system conditions, and thus to minimize the need for any additional procurement of capacity by the CAISO.

5.J.3. Allocation Of The Local Area Capacity Requirement Among Load Serving Entities

57. *The Commission, CEC and CAISO should coordinate to determine the most appropriate means to identify specific LSE responsibility for local capacity requirements based on location of end users.*

The CAISO that will soon be provide to stakeholders a list of substations that can be used to geographically draw the boundaries of each Local Area so that the affected LSEs can determine the loads within the pocket and which LSE is responsible for the local capacity obligation that is associated with that load. The CAISO understands that the PTOs will work with the LSEs in each load pocket to determine the proportion of obligation based on their proportion of load.

5.J.4. Buyer Monopoly & Small Local Requirements

58. *Parties should comment on the pooling approach to increase the ability of smaller LSEs to meet local requirements or the appropriateness of using penalties to procure for capacity the LSEs found unable to do.*

59. *Parties may also suggest alternative approach that would enable them to meet local requirements.*

The pooling idea would be acceptable to the CAISO, as long as any resulting obligations placed on participants are clearly established.

Penalties are appropriate under circumstances where the LSE was able to competitively procure capacity, but failed to do so. Such penalty must be in excess of the price of capacity to operate as a sufficient deterrent. More importantly, the Commission should recognize that the CAISO does not have authority to limit or specify a price at which substitute or supplemental capacity could be procured. In practice, the price for any reliability contract entered into by the CAISO would need to be approved and/or litigated before FERC. Since this price would be unknown until the conclusion of this FERC process, it is difficult for the CAISO to know what penalty might be necessary in order to cover the price of substitute or supplemental capacity procured by the CAISO plus provide an disincentive to rely on the CAISO as a backstop.

As the CAISO has noted previously in these comments, the Commission must be prepared to address this issue in a timely manner. There are solutions to the pricing issue that have been developed in the eastern markets, for example the demand curve utilized by the NYISO. The Commission needs to recognize that should the CAISO be required to enter into local capacity contracts, the FERC is very likely to modify the current pricing methodology to be more reflective of the capacity scarcity.

6.A.1. Scope Of Load Forecasts Submitted

60. *The Commission should confirm that it requires LSEs to submit to the CEC documented hourly load forecasts for all twelve months of the year as part of the year-ahead preliminary load forecast submissions each spring.*

The CAISO supports this obligation.

6.A.2. Schedule For Submission Of Preliminary Load Forecasts

61. *The Commission must choose an annual spring filing date for preliminary load forecasts submissions, and a special date for 2005 reflecting the preliminary nature of the requirements for the first cycle. It must also choose a date by which final load forecasts are returned to LSEs.*

The CAISO has no specific recommendation. The selected schedule for submittals should provide adequate time for preparation and review by CEC staff and LSEs and completion of an expeditious dispute process. Traditionally, the CAISO completes it's own forecasting by the end of March; therefore, the CAISO would favor a late spring submittal (March/April/May) of preliminary forecasts for convenience in comparison.

6.A.3. Documentation Requirements

62. *The Commission must endorse a specific set of load forecast definitions and documentation requirements that support the intended goals of developing acceptable, adjusted load forecasts for each LSE. Parties should provide proposals for specific load forecasting definitions and documentation requirements.*

The CAISO has no specific recommendations, provided that adequate clarity is provided around the terms and methodology of the process.

6.B.1. Plausibility Review of Individual Load Serving Entities' Forecasts

64. *The Commission must determine at the outset, the process by which disputes will be resolved and how much the Commission should delegate to the CEC up-front to avoid further Commission decisions. The Commission must determine what process it will need to adopt to make the CEC's load forecasts determinations final.*

See response to 3.A.1 above.

65. *Since there is no resolution on the issues identified above, we ask parties to comment and provide options on how to streamline the process for the CEC to make final load forecasting determinations.*

See response to 3.A.1 above.

6.B.2. Adjustments For Coincidence & Impacts Of Energy Efficiency, Demand Response And Distributed Generation

66. *The Commission must determine at the outset, the process by which disputes will be resolved and how much the Commission should delegate to the CEC up-front to avoid further Commission decisions. The Commission must determine what process it will need to adopt to make the CEC's load forecasts determinations final.*

67. *The CPUC must determine at the outset if it should delegate load-forecasting tasks to the CEC up-front to avoid further delays through Commission decisions.*

68. *The Commission would benefit from fully understanding whether any appeal rights of an LSE should also be specified along with the process for such an appeal. We ask parties to comment and provide options for the Commission's consideration to streamline and avoid delays or unnecessary Commission orders.*

See above.

6.B.3. Review Of The Aggregation Of Load Serving Entities' Forecasts

69. *The Commission needs to decide whether it will direct the CEC to implement an aggregate load forecast comparison process, and to the extent that discrepancies exceed a specified threshold, such as one percent, that the CEC should make pro-rata adjustments to all LSE load forecasts.*

See above.

6.C.1. Tabulation Of Resources

70. *The Commission needs to decide whether the reporting process and template proposed by the CAISO is generally acceptable and is sufficient to conduct the Year-Ahead resource tabulation review process, and if so to direct that it be modified to match the needs of whichever of the "top-down" or "bottom-up" approaches described in Chapter 2 that the Commission selects.*

The CAISO supports the template and believes it is adaptable to either the top-down or bottom-up approach. The Report indicated that the CAISO template failed to identify resources marshaled to meet local capacity requirements. This is incorrect. The template need not include this information because the CAISO is aware of which resources can be used to meet local capacity needs. As such, the listing of resources/units is sufficient. Nevertheless, the template can be modified to include this designation by the LSE.

6.C.2. Local Resource Adequacy Reporting Requirements

71. *The Commission's Year-Ahead compliance filings must provide a means to demonstrate that each LSE serving load in a load pocket has acquired its fair share of local capacity requirements.*

As noted above, the CAISO that will soon provide to stakeholders a list of substations that can be used to geographically draw the boundaries of each Local Area so that the affected LSEs can determine the loads within the pocket and which LSE is responsible for the local capacity obligation that is associated with that load. This will facilitate the demonstration of each LSE's compliance with its allocation of the local capacity requirement.

6.D. Review Of Year-Ahead Compliance Filings

73. *The Commission must determine whether to approve the working proposal as further outlined in Appendix I.*

The CAISO supports the working proposal.

6.E.1. Month-Ahead Reporting Timelines

74. *The Commission must decide whether the month-ahead filing should be submitted 15 or 30 days prior to the operating month.*

75. *The Commission must also decide whether to adopt the guiding principals for compliance developed by IEP and CAISO that were supported by workshop participants.*

The CAISO supports option 2. With respect to the IEP/CAISO proposal, see response to 2.A.1 above.

6.E.2. Compliance With Month-Ahead Reporting Requirements

76. *The Commission must determine whether it will allow the month-ahead compliance filings to update for load migration or other load changes, and the various resource changes that may be important to address. The Commission must also determine how any update opportunities given to LSEs might affect the 100% year head local procurement requirement for all 12 months.*

Consistent with the need straightforward rules to facilitate implementation by June 2006, the CAISO generally supports SCE's proposal. The proposal does have the disadvantage of not permitting incorporation of more updated information regarding weather conditions and load growth. Nevertheless, in the interim period, the CAISO believes that simplicity should prevail. The CAISO does agree, however, that verified instances of load migration should be accommodated, if possible. The CAISO does not purport to have a detailed proposal to account for load migration, but believes that any accommodation should be allowed only where the load migration is agreed to and accounted for by both LSEs. The LSEs must set forth the amount of transferred load and the identity of the loosing and gaining LSE. The result must be no net change from the year-ahead forecasts. Absent complete information, the transfer is rejected and the LSEs must independently protect their respective rights. The CAISO anticipates that a more comprehensive mechanism to accommodate load migration will be part of the Commission's proceeding to develop a capacity market.

6.E.3. Who Load Serving Entities Report To

77. *As with Year-Ahead compliance review, the Commission must decide whether the CAISO should determine compliance with the year-ahead and month-ahead reports as part of an overall enforcement responsibility.*

The CAISO should determine compliance with the year-ahead and month-ahead reports. However, to the extent the reports are deficient, the Commission should be the entity to impose and enforce sanctions resulting from non-compliance. In addition to the compliance assessments, the timely access to information will allow the CAISO to "load" its operational systems with the expected resources for the upcoming RA period.

6.F.1. Sanctions For LSEs Failing To Submit Or Submitting Incorrect Information

78. *We ask parties to comment on the connection between the resource adequacy requirement time period and the time period used to impose penalties. The Commission will need to fully understand the appropriateness of imposing sanctions over a different timeframe than its required resource adequacy.*

79. *The CPUC should determine the level of penalties on LSEs that do not procure adequate resources.*

A central function of RA requirement is to provide a revenue stream that induces infrastructure investment by permitting suppliers to receive their going forward fixed costs not provided by mitigated energy markets. Simply put, RA has a cost. LSEs will naturally attempt to avoid these costs. Accordingly, the RA requirement must have an economic consequence or it will fail.

Generally, regions that employ an installed or unforced capacity market calculate appropriate penalties for failure to procure based on an analysis of fixed-cost recovery curves. The Report notes that the workshop participants agreed to a similar approach, which sets the penalty at three times the fixed cost for new CT capacity. The CAISO accepts this rather crude proposal as an appropriate initial penalty level during the transition. This is especially true should the Commission modify its earlier decision by adopting a seasonal or annual RA obligation.

The CAISO also agrees that the use of monthly peaks to establish the RA obligation may diminish the effectiveness of the foregoing penalty during the summer months when the value of capacity may near or exceed the penalty. However, this imprecision may be necessary to meet the June 2006 implementation date. If the Commission elects to maintain the monthly RA obligation, the Commission should embark upon an effort to refine the penalty amount.

6.F.2. Sanctions on Generators Failing to Perform

80. *The CPUC must decide whether or not to adopt the CPUC staff / CAISO proposal that splits the RA obligation between generators and LSEs.*

See response to 2.A.1 above.

6.F.3. Administration Of Sanctions

81. *The Commission must decide whether imposition of sanctions by the CAISO or the Commission is most compatible with effective enforcement of the RA requirements.*

See response to 2.A.1 above

6.G.1. Review Of Accuracy Of Load Forecasts

82. *The Commission must determine whether after-the-fact review of load forecasting accuracy is desirable, and if so, how to conduct such review.*

See answer to 3.A.1 above.

6.G.2. Review Of Performance Of Nominated Resources

83. *The Commission must determine whether it wishes for a resource performance tracking process to be developed in addition to the generator obligations to be set forth in the ISO Tariff as discussed above.*

84. *The Commission must determine, whether the CAISO or some other organization is the appropriate entity to prepare these assessments.*

85. *The Commission must determine whether the results will eventually be used in a manner that creates financial incentives for improved generator performance.*

See response to 3 above.

6.G.3. General Features Of After-the-Fact Review Processes

86. *The Commission must determine whether it wants to create an after-the-fact performance review process, and whether it wants this process to be informational or whether it wants ultimately this process to provide financial incentives to LSEs to forecast load more accurately and their nominated*

resources to perform at higher levels and respond more precisely to CAISO dispatch instructions.

The performance of the Commission's RA requirement must be monitored. Each entity, including the CEC and CAISO, should provide the Commission with a report describing the performance of those areas for RA implementation under its responsibility. This report should be provided for at least the first two years of the RA requirement. The Commission can utilize these reports to initiate efforts to modify the RA requirement or to further refine the development of a capacity market.

III. ADDITIONAL TOPICS RAISED BY THE CAISO RELATED TO THE REPORT

A. Deliverability in Non-Summer Months

The RA workshop discussions regarding the Planning Reserve Margin (PRM) have consistently looked at the determination of qualified capacity for peak operating conditions. The ISO proposed and this Commission adopted the notion that resources must be deliverable to load to meet the RAR counting provisions. In addition, the ISO deliverability assessment methodology is based on a set of assumptions for peak system conditions. For example: all transmission lines and generators can be assumed to be in service. As a result, all of the pieces come together to reflect a picture where the peak load can be served effectively by the deliverable resources that qualify for RA counting. However, as a result of the February 8, 2005, Assigned Commissioner's Ruling requesting comments on, among other things, whether the LSE obligation should be based on an annual, monthly or seasonal peak, the CAISO further considered changes in a resource's deliverability from the system peak (summer months) to the off-peak (non-summer months).

The Commission has already determined that LSEs are required to procure sufficient capacity to meet their load plus a 15% PRM. Generally, this margin is intended to provide real-time operating reserves and compensate for such factors as load forecast error and resource forced outages. It was not intended to address deliverability limitations because all qualified capacity is assumed to be deliverable as a condition for counting toward an RA obligation (D.04-10-035 confirmed that RA resources must be deliverable to load). However, the CAISO recently concluded, based on a preliminary analysis of resource deliverability in non-summer months, that some resources are significantly less deliverable during the off-peak period. As a result, if all resources are allowed to count towards a 15% PRM at the same levels as they contribute during the summer months, the uniform PRM would fail to ensure sufficient available resources during the non-summer months. Therefore, the CAISO recommends that the Commission compensate for this issue by adopting a higher PRM for the non-summer months. The amount of the increase and the reasons the increase should not pose a material burden on LSEs is addressed below.

Three principle areas affect the deliverability of resources in the non-summer months. These are lower off-peak load, transmission maintenance outages, and reduced imports from tie-line maintenance outages.
With respect to lower demand, during non-summer months generally less load exists in close proximity to generation and therefore will be lower than that included in the CAISO's deliverability study. As a result, the transmission system is expected to carry more of the resource's output to loads located outside the generator's electrical proximity. If the transmission system is unable to carry the additional load, then the generation and import deliverability results based on peak conditions will overestimate the deliverability for other hours of the year.

Planned transmission outages are typically not scheduled during summer peak load hours, so they do not need to be considered in the deliverability assessment for summer peak load conditions. However, these outages need to be accounted for if adoption of a monthly PRM is to be effective in the non-summer months. There are hundreds of transmission facilities for which unavailability will cause a direct impact on the deliverability of hundreds of generation units connected to the ISO Controlled Grid. The magnitude of this reduction can vary up to 1100 MW. A few examples are shown below.

Transmission Facility Planned Out	**Approximate Generation Deliverability Reduction in MW**
Imperial Valley-Miguel 500 kV line	1100
Lugo 500/230 kV transformer	500-800
Table Mt. 500/230 kV transformer	600-900
Moss Landing-Metcalf 500 kV line	500
Every SPS requiring generation tripping for an N-1 condition	50-1100

Similarly, there are hundreds of transmission facilities that can cause a direct impact on the deliverability of imports into the CAISO Control Area if taken out of service for maintenance. The capacity impacted by the unavailability of these lines is fairly significant. For example:

Transmission Facility Planned Out	**Approximate Import Deliverability Reduction in MW**	**Approximate ISO Allocation Import Reduction in MW**
Palo Verde-Devers 500 kV line	600-2170	360-1302
Olinda-Tracy 500 kV line	1700	1020
Imperial Valley-Miguel 500 kV line	1180	708

In sum, performing a deliverability analysis of non-summer operating seasons would need to include consideration for these additional factors. Yet, the ability to anticipate the existence of any one, or combinations of these factors makes it almost impossible to establish a set of study assumptions that would result in new deliverability based counting provisions for resources in non-summer months. Furthermore, such an analysis would be more complex than the summer peak deliverability analysis, and would likely require the development of an entirely new methodology. It is expected that such a study would require several months to establish an agreed upon methodology and several more months to develop preliminary results. This does not seem practical for the 2006 RA compliance period.

As noted above, rather than embarking on an effort to precisely determine a level of deliverability for each unit during non-summer seasons, the CAISO recommends that the Commission compensate for this issue by adopting a higher PRM for the non-summer months the CAISO recommends. This solution is manageable and is unlikely to impose on LSEs a meaningful increase in the administrative or cost burden associated with RA procurement. Under a monthly or even seasonal RA obligation period, capacity prices will likely be high only during the peak periods when it is most valuable, and inexpensive in the off-peak period when capacity is relatively more plentiful. Accordingly, the incremental cost of procuring capacity for other the off-peak seasons may be minimal. The CAISO's approach would allow the same qualifying capacity for any single resource during any obligation period, but the LSEs aggregate procurement obligation would be adjusted for the potential that some resources are undeliverable during non-summer months. The CAISO's analysis reveals that the level of deliverability derates during the off-peak for each problem area is a range. An estimate of these ranges in additional capacity is shown below.

Description of Deliverability Issue	Approximate MW needed to Compensate for Problem	Approximate % of 30,000 MW Monthly peak needed to Compensate for Problem
Deliverability Issues Caused by Off-Peak Load	800-1000	2.7-3.3
Generation Deliverability Issues Caused by Planned Transmission Outage	500-1100	1.7-3.7
Import Deliverability Issues Caused by Planned Transmission Outage	360-1302	1.2-4.3
	1660-3502	5.5-11.7

Based on this information, the ISO recommends the Commission revise the standard 15% PRM and order that LSEs procure an additional 8% (on a monthly peak load basis) of capacity during non-summer months.

B. Short Start Units

- D.04-10-035 required that RA resources must make themselves available in the CAISO's Day-Ahead Integrated Forward Market, including the Residual Unit Commitment ("RUC") process. The decision left open the question whether "short start" resources that are physically capable of responding to changes in system conditions after the DA commitment process must make themselves available to the CAISO in Hour-Ahead and/or real-time markets. in accordance with dispatches have been made and any real-time operating condition is foreseen or actually occurs.as to what obligations are necessary after the DA/RUC unit commitments have been completed. The CAISO believes the Commission should modify its earlier decision and extend the requirement for RA resources to make themselves available into real-time where the resource is physically capable of performing on short notice.

Reliability (security) of the system requires that the system operator have the ability to call on units capable of meeting system needs. In D.04-10-035, the Commission required that RA be made available to the CAISO in the Day-Ahead market and RUC. The Commission did not address the specific obligations of short-start resources. Recognizing the need to balance the CAISO's ability to rely upon short-start resources to reliably serve load and satisfy system reliability requirements and the desire to efficiently and fairly commit and dispatch short-start resources, the CAISO previously raised the short-start issue in the context of its MRTU stakeholder process.

At the May 18th and 19th MRTU meetings, the CAISO identified three options for defining the offer obligations of short-start resources:

Option 1 – short-start resources must be available for commitment in the CAISO's day-ahead market and RUC process. To the extent committed by the CAISO in the day-ahead timeframe, such resources would receive appropriate compensation as well as the applicable real-time price if dispatched and would be available for dispatch in real time as needed. If not committed by the CAISO in the day-ahead timeframe, short-start resources would be released from any obligation to be available in real-time. Under this approach, the CAISO presumes that such resources will factor in anticipated market opportunities (revenues) when negotiating RA contracts with LSEs, including making themselves available with revised bids in the CAISO's hour-ahead market or HASP.

Option 2 – short-start resources must stand ready for real-time commitment and dispatch by the CAISO. Under this approach, the CAISO will issue day-ahead commitment instructions to short-start resources that meet an identified need and any resources not selected must be held in reserve for possible real-time use. Under this approach, the CAISO presumes that such resources will require compensation for holding their resource in reserve.

Option 3 – short-start resources must stand ready for real-time commitment and dispatch by the CAISO. However, the CAISO attempts to design a mechanism where a portion of short-start resources could be released from any offer obligation after the day-ahead process. Under this approach, the CAISO presumes that such resources will require compensation for holding their resource in reserve, but resource owners be in a better position to reduce the reservation cost because of opportunities to offer elsewhere.

As evident from the foregoing options, the CAISO is sensitive to stakeholder interests in an obligation that allows short-start units flexibility to take advantage of other opportunities to sell their output in markets after the CAISO day-ahead commitment process. In considering the RA based must-offer obligation for short-start resources, a number of issues need to be addressed. First, the current MRTU design contemplates retaining the offer obligation of short start units into real time dispatch. Solid justifications support this design. RUC is designed to utilize the CAISO load forecast and the Full-network model to determine the necessary resources to meet load plus the necessary operating reserves for the next day operations. Yet, this dispatch cannot foresee operational contingencies.[13] In any given hour, the CAISO will need to carry sufficient resources to meet load plus its operating reserve requirements. The day-ahead/RUC dispatch is intended to meet these requirements with a day-ahead dispatch. However, the forced outage of any resource will cause the CAISO to be below its requirements. The WECC MORC requires the CAISO to restore this reserve in one hour from the precipitating event. Unfortunately, the CAISO is not able to foresee when, where, or the magnitude of these contingencies should they occur. In addition, the IFM and RUC are designed to minimize, but cannot completely address, the need to respond to significant amounts of load ramping. This occurs because the unit commitment algorithm considers the ability of available resources to ramp over sixty minutes from the mid-point of one hour to the mid-point of the next hour. In the event extreme amounts of load are ramping up or down, there will remain a short period at the top of the hour where a fast ramping resource is necessary to assist the committed units. Thus, the CAISO believes it is necessary that RA based offer obligations require short-start resources to not only be available during the day-ahead market and RUC, but also available into real-time.

Further, stakeholders were concerned that such an obligation would add significant cost to the procurement of RA capacity. If short-start resources are defined as those non-hydro resources with the ability to perform a cold start in less than 2 hours, then approximately 100 units for a total of 7,000 MWs meet this criterion.[14] However, a more deliberate review of these resources yields two relevant points that mitigate potential cost impacts. First, most of the short-start capacity is located within the eleven load pockets defined by the local deliverability requirements. As a result, it was agreed by all workshop participants that local capacity is required to be available for 24 hours of each day of the year. Second, the additional short-start capacity that is outside the local areas is most likely hydro facilities that provide great value to the CAISO control area. Such assets are likely to be very active in the Ancillary Services markets or otherwise providing reserves to the CAISO. These markets provide revenue opportunities to these resources that must be available to the CAISO after the day-ahead. Finally, the CAISO MRTU deign allows for all scheduling coordinators to bid load for export into the day-ahead market. To the extent these loads clear the day-ahead market and can be served by

[13] These would include the scenario in which a long start unit is committed for the up coming day but is unable to successfully start. The CAISO would initially look to acquire the replacement capacity from resources available in the HASP. However, any residual need must come from SS units.

[14] CAISO considers this population without hydro resources because hydro resources are likely to already be online during run-off conditions or be selected in the DA/RUC markets to provide ancillary services. The hydro resources include an additional 139 units with a total capacity of 10,000 MWs.

the resources making themselves available, the export will receive firm transmission service from the CAISO. Therefore, the CAISO does not believe the added requirement to hold short-start units in the real-time will result in any demonstrable increase in capacity costs.

Regarding whether short-start units can receive waivers as proposed in Option 3, the CAISO wishes to make its unit commitment and offer requirements as cost effective as reasonably possible, while balancing its needs to achieve a reliable system. Given the existing quantity and the potential for short-start resources to increase in the coming years, it may be possible to allow for some resources to receive waivers from the RA based offer obligations. However, based on the previous points regarding reliability needs and revenue opportunities under MRTU, the CAISO does not believe the time and level of effort to realize such an objective is justified in the foreseeable future.

Accordingly, the CAISO believes Option 2 is the most effective solution and the incremental cost, if any, for this operationally valuable subset of system resources is consistent with an effective resource adequacy framework to ensure sufficient capacity is available to California. The Commission must clearly define the short-start offer obligation so resource owners and LSEs can appropriately price their respective commitments and obligations. The CAISO believes the Commission should adopt such a reliability-based obligation on short-start resources and modify its earlier decision to extend the requirement for RA resources to make themselves available into real-time where the resource is physically capable of performing on short notice as defined above.

C. Counting Resources with Planned Maintenance

The Joint Parties propose that resources having only a portion of the month scheduled for a planned maintenance outage should still be counted towards RAR because the CAISO is the outage coordination authority.

Under the Joint Parties' approach, any significant period of the month means the CAISO has access to fewer resources. To add further complication, many planned outages are delayed from their scheduled return and very few actually return early. Therefore, the CAISO would recommend that this notion only be allowed for planning purposes when the resource is expecting a maintenance need that is less than one fourth of the month (one week). Further, any outage approved by the CAISO will not negatively affect the RAR obligation to be available to the CAISO.

D. Partial Units & Long Start Units

There is no need for the Commission to make any rulings on these issues, which were discussed at the CAISO's June 22-23, 2005 stakeholder meetings. The CAISO anticipates being able to resolve these implementation issues in the near future, i.e. MRTU release 1 or 2. The CAISO recognizes the need to accommodate the procurement practices in the industry with regard to procurement of "partial units" and include a multi-day unit commitment process.

July 13, 2005

Respectfully Submitted:

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California Independent System Operator

RAR Local Capacity Procurement
Straw Proposal

June 23, 2005

RAR Local Capacity Procurement

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RAR Local Capacity Procurement
Straw Proposal

Introduction

On January 25-26, 2005, the California Independent System Operator Corporation ("CAISO") presented a revised proposal for satisfying the California Public Utilities Commission's ("CPUC") local capacity area requirement being developed through the Resource Adequacy ("RA") Phase 2 workshops. While the revised proposal was largely accepted regarding the methodology the CAISO would use to define the local capacity requirements, certain information to facilitate procurement was unavailable. This document discusses the key issues regarding local capacity procurement and it is intended to be the starting point for development of the necessary local capacity procurement details that will enable load serving entities ("LSEs") to optimize their procurement obligations to assist the CAISO in satisfying applicable reliability criteria.

The Phase 2 workshops have produced a consensus that 100% of local capacity requirements must be at the year-ahead timeframe and that units procured to meet the obligation must be available to the CAISO on a 24x7 basis. This document goes beyond these agreed upon general principles to discuss in greater detail the required operational characteristics of the resources eligible to satisfy the local capacity requirements, the CAISO's ability to dispatch the procured resources, and the process for transitioning from the current local reliability paradigm to a new one following implementation of the CPUC Resource Adequacy Requirements ("RAR") framework and the CAISO Market Redesign and Technology Upgrade ("MRTU") project.

The CAISO requests that stakeholders provide comments on the topics discussed in this document and participate in an effort to develop a standard set of requirements all LSEs will use to meet the local capacity obligations. In this way, the CAISO hopes to promote an efficient means for LSEs to contract for local capacity.[1]

Operational Characteristics

Issue

Define the operational requirements of the resources eligible to satisfy the local capacity requirements. Payment terms for LSE contracts will be left to each LSE to negotiate with the resource provider on a case-by-case basis; however, the document will

[1] A local capacity market is likely to be a more efficient means to procure the local capacity.

address some guidelines to ensure there are appropriate incentives.

Access to Full Capability of Resources

The terms of the contract should provide the CAISO access to the full capabilities of the unit to provide Ancillary Services or Energy unless it is in an approved planned or force outage. This includes the ability to decrease and increase unit output, instruct shutdown or minimum load operations; i.e., the CAISO may instruct the unit to decrement its output or shutdown for reliability reasons. The CAISO will respect all resource limits that reflect the physical operating characteristics such as minimum run times, etc..

Use-Limited Resources

Ideally, the local capacity resources should not be use-limited resources; however, realistically, use-limited resources may be capable of enabling the CAISO to operate under the applicable reliability criteria. The challenge is to define how much service will be required. Unfortunately, the CAISO does not have a crystal ball to determine the amount; therefore, the CAISO would like to use this document as an opportunity to solicit stakeholders proposals on a process or terms that will ensure the resources can fulfill the applicable reliability criteria. One alternative is for energy and/or service hour limited resources to provide a mechanism allowing the CAISO to obtain a "call option" on all or a portion of the applicable period energy and/or service hours to meet reliability requirements. Demand Response, Distributed Generation and Intermittent Resources will not be eligible to satisfy the Local Capacity RAR.

PGA & MSS Market Operating Characteristics

Local capacity resources should be required to operate under the characteristics as specified for the resource in Schedule 1 of the Participating Generator Agreement ("PGA") or Schedule 14 of the Metered Sub-System Agreement ("MSSA") as applicable. CAISO should be provided the authority to dispatch the resource to the operating limits wherever necessary to maintain the applicable reliability criteria. Each resource should be required to comply with the CAISO Tariff as specified by the PGA or MSSA including compliance with the Outage Coordination Protocol or its replacement. This contrasts to the practice under the Reliability Must-Run Agreements in which the operating characteristics are in some instances different than the characteristics specified in the PGA or MSSA. The values for the PGA or MSSA are contained in the CAISO's Master File and some of the values may be adjusted to reflect actual operating conditions. The CAISO desires this approach because it offers more operational flexibility and enables the Owners to make adjustment to reflect actual operational values such that the CAISO may consider these in its dispatch notices. The Operational Characteristics listed in Appendix 1 provides a guide to the types of information LSE's should consider including in its local capacity procurement agreement. Stakeholders should also comment on the suggested guidance values provided. Questions: Under what circumstances will MSSA resources be eligible for use?

Dispatch For Any Reliability Reason

While the CAISO will be identifying the local area reliability resources specifically for a "local area" requirement, these contracts shall allow the CAISO the ability to dispatch the resources for the purpose of maintaining any network element within its normal operating limits under any system-wide energy shortage and A/S requirement, not just local or intra-zonal congestion; i.e. complete dispatchability for any reason such as local/zonal/system. There shall not be a notice requirement associated with the intended use of resources.[2] With implementation of MRTU, congestion will be defined to include both the intra and inter categories, so a distinction will no longer be relevant and all LSE's will be providing a proportionate share of the reliability capacity.[3]

Compliance Incentives

There needs to be a strong incentive for the generation resource to remain available to the maximum extent possible and to respond whenever the CAISO requests a start oran increase or a decrease in output. In the RMR Agreements, this incentive has been provided through availability payments and non-performance penalties, However, there have been problems with this approach, so the CAISO desires a new approach be developed. Some suggested approaches would be to define critical periods of availability and impose severe penalties if the units did not respond if called during these periods. Questions: How is penalty determined? Is UDP in CAISO market sufficient? Is LSE or Resource owner penalized? Who will enforce penalty?

A just and reasonable rate should be paid in consideration of the key operational and dispatch capabilities that are established by the terms of the contract.

Dispatch Requirements

Issue

Define the dispatch elements of the local capacity obligation to provide the CAISO ability to dispatch the resources procured to meet the applicable reliability criteria.

Day-Ahead Commitment

The CAISO must have the ability to commit the local capacity resources at any level the day prior to the operating day if such commitment is necessary to maintain compliance with applicable reliability criteria. The commitment mechanism will be slightly different in each of the transition periods described below. The CAISO proposes the Day Ahead commitment as follows:

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[2] In addition to other requirements, the RMR Agreement requires a notice prior to dispatching an RMR Unit to provide Ancillary Services.

[3] As long as the dispatch mechanism appropriately covers the costs for dispatch, each LSE will be protected from paying a disproportionate share. While it would be nice to have an appropriate mechanism to ensure the cost is paid by the entities benefiting from any service, this is not likely to be feasible until the market design implements nodal pricing for loads.

Period 1 – Before RAR

The CAISO will dispatch the designated RMR Units using the current process and CAISO systems (e.g. the RMR Client and GRRMA).

Period 2 – RAR before MRTU

The CAISO proposes to issue dispatch notices to both LSE local capacity resources and any remaining RMR Units in the Day-Ahead ("DA") time frame using the RMR dispatch systems. The dispatch can be optimized using one of three proposals:[4]

1. Use current Pre-dispatch process in which the units are selected based on their effectiveness;
2. Evaluate the initial DA schedules and only dispatch in accordance with the incremental RMR requirements which would be scheduled in the final DA Schedule;
3. Commit units under the must offer process and increment them up in real time to satisfy the reliability requirements; this is the least desirable option because it is likely to necessitate the decrementing of resources scheduled in the DA schedules to make room for the RMR/LARC units.

The CAISO will evaluate these alternatives further and make a recommendation on a preferred approach after receiving stakeholder comments.

Period 3 – RAR and MRTU

The CAISO would commit and dispatch all units to maintain applicable reliability criteria using the through the MRTU software. Resources with long-start characteristics may need to be dispatched using an off-line manual dispatch process if the MRTU functionality is unable to meet these limitations.

Real Time Dispatch

The Local Capacity resources must bid all available capacity and energy into the next available CAISO market, consistent with its physical operating parameters and including up to real-time, to offer CAISO access to all the energy and ancillary services the resource is capable of providing.

Transition

Issue

Process for Transition from the current local reliability paradigm to a new one satisfied following implementation of the CPUC RAR framework and the MRTU project.

[4] A cost based bid or an alternative ranking methodology may be required to implement options 2 or 3 to optimize the dispatch selection.

Before RAR ("Period 1")

The *"Before RAR"* period is between the present and the date the RAR obligations are ordered by the CPUC to be effective ("Period 1"). Based upon current expectations that the RAR obligations will begin June 1, 2006, Period 1 would end on May 31, 2006. During this period the CAISO will continue to use the existing mechanisms to meet the applicable reliability criteria. For the 2006 Contract Year, designation of RMR Units will be determined using the RMR Criteria that was also used for the 2005 Contract Year designations (see discussion below under the heading *"2006 LARS to June 2006 RAR Local Capacity"* for further details regarding transition from RMR to RAR).

RAR Before MRTU ("Period 2")

The *"RAR Before MRTU"* period begins on the date the RAR obligations are effective and ends the hour before the MRTU project is implemented ("Period 2"). Based upon current expectations Period 2 is expected to begin June 1, 2006 and end January 31, 2006. There is an opportunity to eliminate RMR Agreements during Period 2 if the LSE's Local Capacity procurement provides the CAISO the ability to dispatch sufficient local capacity resources to meet the applicable reliability criteria. If the LSE's local capacity procurement is not sufficient, the CAISO will continue to rely on the 2006 RMR Units and potentially additional resources procured through a new Local Area Reliability Contract as described below. The CAISO needs to determine whether or not its Tariff would need to include a mechanism to allow the CAISO to dispatch the resources procured by the LSE's during this period (this will depend on FERC's view of the existing must-offer obligation and waiver process).

RAR and MRTU ("Period 3")

The *"RAR and MRTU"* period is defined by the period when both RAR and MRTU have been implemented ("Period 3"). This period is expected begin February 1, 2007 and continue on indefinitely. Integration Requirements: Identify the mechanism the CAISO will use to ensure the required capacity is offered into the CAISO markets and provides service when it is needed to meet local area reliability criteria and/or to relieve congestion.

<u>CAISO Local Area Reliability Contract</u>

The CAISO will propose a new reliability agreement or the CAISO Local Area Reliability Contract ("CAISO LARC") to serve as a replacement for the existing Reliability Must-Run ("RMR") Agreement. The CAISO LARC will continue to provide the market power mitigation role the RMR Agreement has played for generators located in constrained areas of the grid. The CAISO LARC would be fashioned to harmonize with both MRTU and RAR. In addition, the CAISO LARC should be written to ensure several RMR Agreement deficiencies do not persist. Among the RMR Agreement deficiencies are a restriction on use for system purposes, isolated cost allocation, limitations on use for ancillary services, and constraints on market participation. A stakeholder process will be conducted to provide Market Participants the opportunity to shape the final terms and conditions of the CAISO LARC. CAISO will propose the CAISO LARC will have similar terms and requirements as the ones guiding LSE local capacity procurement.

2006 LARS to June 2006 RAR Local Capacity

The CAISO will use the current RMR criteria to designate RMR Units in the 2006 Local Area Reliability Service ("LARS") process and proposes a process as described below to integrate the LARS 2006 process with the RAR, Local Capacity obligations expected to be effective beginning June 2006. The CAISO will rely on the designated RMR Units, the RAR Local Capacity procured by load serving entities ("LSEs") beginning June 1, 2006 and either the Must Offer Obligation ("MOO") or additional capacity the CAISO may secure under a new reliability contract as described above to provide the capacity for reliable operation of the ISO Controlled Grid in 2006.

With the RAR Local Capacity obligation beginning on June 1, 2006, RMR Units must be designated for 2006 to meet local reliability requirements for the January 1 through May 31, 2006 period; however, the RMR Agreement term is for the calendar year. The CAISO may extend the term for less than a full calendar year as to one or more RMR Unit but only if CAISO gives notice not less than 12 months prior to the date to which it proposes to extend the term. The CAISO will not know whether or not the extensions should be for less than a calendar year prior to October 1; therefore the CAISO intents to extend the 2005 RMR Units identified as required to meet the RMR Criteria for the entire 2006 Contract Year.

If an LSE contracts with an RMR Unit designated for 2006, the CAISO would be willing to terminate the RMR Agreement as to those RMR Units early with mutual agreement of the RMR Owner. To facilitate this, any agreement between the LSE and RMR Unit Owner intend to meet the RAR Local Capacity obligation should stipulate that the RMR Unit Owner be willing to mutually agree with the CAISO to terminate the RMR Agreement effective midnight on May 31, 2006; the CAISO will agree to this early termination only if the CAISO continues to have a mechanism to dispatch the affected RMR Unit(s) under the LSE contract as it currently has under the RMR Agreement.

Appendix 1 – Generation Characteristics

1. Description of Facility/Units

	Unit 1	Unit 2	(min, reqmts)
ISO Resource ID			
Maximum Net Capacity[5]			10 MW
Fuel (Natural Gas, Diesel, Oil, etc.)			
Type (fossil, combustion turbine, etc.)			
Synchronous Condenser Capability (Y/N)			
Power Factor Range (lead to lag)			0.95-0.90
Maximum Reactive Power Leading, Mvar			
Maximum Reactive Power Lagging, Mvar			
Load at Maximum MVar Lagging, MW			
Load at Maximum MVar Leading, MW			
Black Start Capable (Y/N)			
Automatic Start or Ramp (Y/N)*[6]			

2. Operational Limitations
   - *List applicable NOx, CO, SO2, particulate, and other appropriate emissions limits; note the name and address of the lead agency; the agency's applicable rule number(s); and note those pollutants for which an emissions cap applies.*
   - *List Maximum annual operation, Monthly Reserved MWh for Air Emission Limitations, Operating Limits related to Ambient Temperatures, Ambient Temperature Correction Factors (Provide a curve or table showing the Ambient Temperature Correction Factors for each Unit to describe the relationship between Ambient Temperature and Maximum Net Dependable Capability), FERC License Conditions (hydroelectric Units), Other Limits (e.g., cooling water discharge)*

3. Interconnection Point

   First point of interconnection with the ISO Controlled Grid. Must be a transmission node within the local area defined by grid planning

Unit	Transmission Node	Voltage

4. Deliverability Limitations

   Generation to be counted to meet Resource Adequacy reserve margin

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[5] The maximum net capacity value shall to reflect any transformer line loss to the Delivery Point; reductions to this value shall be reported through the CAISO outage reporting system. Pmax's is validated through testing (to match unit rating), including all constraints under summer peak load hour conditions (ambient temperature, water temperature, Nox, Sox, common penstocks, etc.)

[6] If "Y", describe the conditions under which the Unit will start or ramp automatically

requirements and local capacity requirements must be deliverable during summer peak load conditions as determined by an CAISO Deliverability Assessment.

5. Metering and Related Arrangements

Must be a meter polled by the CAISO

Unit	Meter Location	Meter Type

6. Minimums: Load, Run Time, Off Time
   - Pmin's are uninhibited for over-generation, congestion, etc. (i.e. 10-20% of pmax, physical equipment limitations, not a function of heat rates, pollution, etc.)
     - Individual Pmin's for combined cycle units
   - Minimum up time based on physical equipment limitations
   - Minimum down time based on physical equipment limitations
   - Percentage of short-start units per local area (4000 MW generation in load area, 400 MW short-start for loss of largest unit)

No specific requirements; values in agreement shall match the values in the CAISO Master File.

Unit	Manual Minimum (MW)	Dispatchable Minimum (MW)	Minimum Load (MW)	Minimum Run Time (minutes)	Minimum Off Time (minutes)

7. Maximum Annual Generation Commitments: MWh; service hours; start-ups
   - Unlimited start-ups based on physical equipment limitations

Based on an average of the unit's total annual net output (MWh) for the past five years, and an average of the unit's total annual running hours for the past five years. Also, provide the number of start-ups each unit has incurred in each of the past five calendar years for each unit offered at the Facility; if less than five years of history; the requirements will be determined by consultation with O/E and their determination of expected MWh, service hours, and start-ups required to meet reliability needs..

Unit	MWh	Service Hours	Start-ups

8. Start-up Lead Times (per unit)
   - Start time based on physical equipment limitations

Generating Unit Start-up Time (Minutes) shall be the time needed from notification to Pmin as defined in the CAISO Tariff. The Start-up Lead Time to be used for dispatches and settlements shall be the Startup Time submitted by the Owner through the process as defined in the CAISO Tariff.

Unit	Start-up Segment Number	Generating Unit Down Time (Minutes)	Generating Unit Start-up Time (Minutes)

9. Ramp Rates
    - Reasonable ramp rates – i.e. 5-10 MW / minute based on physical limitations

    Separate Ramp Rates will be shown for each load range and will describe any special restrictions affecting Ramp Rates at various load points, e.g., feed pump operation, heat soaks etc.. The Ramp Rate shall be the Operational Ramp Rate submitted by the Owner through the process described in the CAISO Tariff. The values in the CAISO Master File shall be equal to the values the applicable values for the agreement.

Unit	Ramp Rate Point Number	Output of Point Range (MW)	Minimum Ramp Rate (MW/Minute)	Maximum Ramp Rate (MW/Minute)

10. Variable Costs

    LSE to cover the costs whenever the unit is required to operate to meet local area reliability needs

11. ISO Dispatchable

    The Units the LSE's procure to meet their to cover the costs whenever the unit is required to operate to meet local area reliability needs

California ISO

LOCAL CAPACITY TECHNICAL ANALYSIS

OVERVIEW OF STUDY REPORT AND PRELIMINARY RESULTS

June 23, 2005

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Local Capacity Technical Analysis Overview and Study Results

I. Executive Summary

As part of the Phase 2 workshops on the implementation of Resource Adequacy Requirements ("RAR"), the California Public Utilities Commission ("CPUC") asked the California Independent System Operator Corporation ("CAISO") to perform a technical analysis on the amount of generation capacity that is necessary within transmission constrained areas of the grid. This overview summarizes how the CAISO analysis was conducted and the preliminary results of this analysis.

Generally, the results of this study produced MW requirements within Local Capacity Areas that are significantly higher than the amount of Reliability Must Run ("RMR") contracts that have been signed utilizing the CAISO's Local Area Reliability Service ("LARS") technical analysis. In addition, this technical study identified two additional Local Capacity Areas beyond those already established by the LARS technical studies as transmission constrained local areas in which generation capacity is needed to ensure reliable operation of the CAISO Controlled Grid.

The difference in MW requirements between this Local Capacity Area technical study and LARS arises from the goal of local RAR to permit the CAISO to meet its operational and planning requirements within areas with severely limited transmission capability. The scope of LARS is more limited. The current RMR Criteria is basically a subset of the Grid Planning Standards that includes only single contingencies (NERC Category B). The criteria for this study expands the subset of contingencies to include simultaneous and overlapping double contingencies (NERC Category C). In addition, the current RMR criteria requires an assessment of the system with 1 in 5 summer peak load level, while this study assumes a 1 in 10 summer peak load level.

As an example, under this Local Capacity Area analysis the CAISO must operate the grid with an ability to recover from overlapping contingencies in which a major facility is lost from service, the system is then readjusted, and then another major facility (N-1 or common mode N-2) is lost from service. The modification of assumptions to more closely reflect the CAISO's operational requirements results in higher MW needs within the affected Local Capacity Areas compared to previous LARS studies. These are the actual conditions under which the CAISO must plan and operate the CAISO Controlled grid. Therefore, the CAISO believes this study reflects the necessary and appropriate levels of resources for an effective local capacity obligation.

II. Introduction

This overview report summarizes the CAISO study methodology, criteria and preliminary results for the "CAISO Controlled Grid Local Capacity Technical Study." This study is intended to provide the technical basis for local capacity requirements that must be met for an effective Resource Adequacy program.

The parameters of the study were initially presented and discussed with stakeholders at a CPUC workshop conducted at the CAISO on January 25, 2005. The proposed methodology and criteria for this Local Capacity Area technical study were published as part of a "Straw Proposal" document that was distributed to the CPUC service list of workshop participants. This document has since been posted on the CAISO website at:

http://www.caiso.com/docs/2005/06/22/2005062214371421107.pdf

This overview includes the preliminary results of the study, expressed in MWs that are meant to define the minimum amount of capacity that is needed in each Local Capacity Area for reliable operation of the CAISO Controlled Grid.

This overview also identifies the transmission lines into these Local Capacity Areas and the substation facilities[1] that encircle or are included within each Local Capacity Area. The CAISO believes this information can be used to geographically define each Local Capacity Area and to assign specific local capacity obligations to the load serving entities ("LSEs") that serve load within these geographic boundaries. The CAISO anticipates that the CPUC will establish such an allocation mechanism through the CPUC's upcoming orders on Resource Adequacy.

III. Background and Description of Local Area Requirements under Resource Adequacy

The regulatory framework adopted by the CPUC in the October 28th 2004 decision on resource adequacy includes three distinct categories by which generators would be assessed for their ability to deliver the output of electricity, and thereby count toward meeting an LSE's resource adequacy obligation.

The deliverability of generation to the aggregate of load measures the ability of generators to provide energy to the CAISO transmission system at peak load and not be limited by the transmission system or dispatch of other resources in the vicinity. The CAISO conducted a baseline study assessing the deliverability of

[1] The CAISO is confirming the names of some of these substations and expects to present this information in other documents soon to be posted.

existing generators and presented the preliminary results to stakeholders on May 9, 2005. An additional phase of this baseline study will be conducted soon to account for new generation projects with approved interconnection studies. Thereafter the deliverability of new resources will be assessed incrementally as part of the CAISO's technical studies to ensure the safe and reliable interconnection of new generators.

The deliverability of imports identifies the MW amounts that should be considered deliverable from outside the CAISO Controlled Grid through import paths. For this initial assessment, the CAISO analyzed data that reflected the historical use of intertie points between the CAISO's Controlled Grid and neighboring systems. The preliminary results for the deliverability of imports category also were presented to stakeholders on May 9, 2005.

The third leg of deliverability is the focus of this study and overview report. The deliverability to load within transmission constrained areas identifies the MW amounts of generating capacity that must be procured within load pockets to reliably serve the load located within these areas of the CAISO Controlled Grid.

All three categories of deliverability are assumed to be part of the resource adequacy rules that will be implemented in June, 2006. It is expected the CPUC will require that specific resources must be deliverable to the aggregate of load in order to count as qualified capacity meeting an LSE's overall resource adequacy obligation. Generating units within load pockets that qualify as deliverable to load within a transmission constrained Local Area could count both toward the Local Capacity Area obligation and the overall RA obligation for an LSE.

As part of this final report the CAISO intends to identify the generating resources that are eligible for meeting the MW amount that must be procured within each transmission constrained area. These Local Capacity Areas very closely resemble the areas in which the CAISO designate RMR Units for the 2005 Contract Year. This occurs because local generation must be used to serve load due to the limited ability of transmission lines to deliver output from resources located outside the transmission constrained area.

The CAISO intends to phase out RMR. In an accompanying White Paper that will be discussed at the June 29, 2005 stakeholder meeting, the CAISO begins to describe the necessary operational requirements for LSE procured resources. In addition, the CAISO proposes a process for transitioning to the LSE's procuring Local Capacity resources under new rules established in the CPUC's RA proceeding.

It is possible that the flexibility in LSE procurement may result in a set of resources that meets the MW obligation, but does not fully ensure the CAISO's ability to respond to all contingencies. Therefore, the CAISO expects to develop a Local Area Reliability Contract ("LARC") where the CAISO may enter into a contract in a limited or "backstop" role to ensure the reliable operation of the CAISO Controlled Grid within the redesigned market and Resource Adequacy paradigm.[2]

Finally, the CAISO intends to perform this Local Capacity Area technical analysis annually. However, the transmission constraints that give rise to the Local Capacity requirement may be relieved with the introduction of additional transmission infrastructure. While this is certainly feasible, the CAISO anticipates that the boundaries of Local Capacity Areas will be fairly static over a 3-5 year time horizon and the minimum amount of capacity procured within each Local Capacity Area should remain reasonably stable. In short, the Local Capacity requirement for each Local Capacity Area may decline as transmission improvements relieve constraints, or increase proportionally as load grows; however, LSEs should be able to anticipate these changes over the long-term in order to strategically plan how to reach their procurement targets.

IV. The Study

A. Objectives

The purpose of this annual study is to determine which specific areas within the CAISO Controlled Grid exhibit local reliability problems and what MW amount should be targeted to provide the capacity needed to mitigate these potential local reliability problems. The results of this overview will show:

A. The total generation capacity (in MWs) that must be available within each Local Area.

B. A list of the transmission lines and substations that encircle each Local Area, from which a geographical description can be drawn to identify which load is encompassed within each pocket.

In addition, the final study report will include a list of generating units that are located within each Local Capacity Area and therefore eligible to count toward meeting the local requirement. Generator deficiencies in Local Areas also will be described to highlight areas where some generating units exist, yet the reliability criteria are not met due to the insufficiency of these resources.

B. Key Study Assumptions

The CAISO utilized the "2006 CAISO Controlled Grid – Summer Peak" as the base case. This base case was adjusted to reflect a one-in-ten-year peak load forecast that was provided by the Participating Transmission Owners ("PTOs").

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[2] LARC may also serve as a backstop mechanism to address the exercise of market power for local capacity.

The CAISO also utilized electronic contingency files provided by the PTOs. This information includes remedial action and special protection schemes that are expected to be in operation prior to 2006.

The assumptions related to generation adopted for this study are similar to the assumptions made for RMR studies, including the availability of "Must Take" resources at their contract ratings, the dispatch of hydro generation and the explicit representation of municipal, state, federal and QF generating units in the power flow base cases. However, the Local Capacity studies include the MWs value of these units where the RMR studies did not.

C. Methodology and Summary of Criteria

This study applies the established planning and operating standards of the CAISO to determine the necessary reliability standards within Local Capacity Areas. These planning and operating criteria are consistent with the NERC/WECC standards that address system performance levels A, B and C.

Performance Level A is a normal operating condition with no overloads and all voltages within their normal operating limits.

Performance Level B incorporates N-1 contingencies that could include the loss of a single generator, a single transmission line or a single transformer bank. This standard requires enough generation so that the system avoids voltage collapse or transient instability as a result of these potential N-1 scenarios. The transmission system also should remain within emergency thermal limits and acceptable voltage limits. Following this N-1 contingency the generation must be sufficient to allow for operators to bring the system back to within acceptable (normal) operating range (voltage and loading) and/or appropriate OTC.

Performance Level C requires sufficient generation for the system to absorb the loss of a generating unit or transmission facility, readjust to a normal operating state, and then suffer the loss of another transmission facility. This standard requires a MW amount within that Local Capacity Area sufficient to keep the system within emergency thermal limits and acceptable voltage limits, as well as avoiding voltage collapse and transient instability.

Performance Level C also incorporates N-2 contingencies that could include the simultaneous loss of two transmission lines or two generating units. This standard requires enough generation so that the system avoids voltage collapse or transient instability as a result of these potential N-2 scenarios. The transmission system also should remain within emergency thermal limits and acceptable voltage limits.

Finally, for the large local areas (e.g. over 2000 MW of load) this study incorporates operating requirements for "N-1, followed by N-2" contingencies that go beyond NERC Performance Level C standards. This would include contingencies where the system suffers the loss of a single generating unit or transmission line, the system is readjusted and then the simultaneous loss (common mode failure)[3] of two transmission lines occurs. Under these contingencies the CAISO would be allowed to shed load,[4] and the criteria requires only enough generation available to prevent voltage collapse or transient instability.

Hundreds of thousands of simulations were run to determine the largest potentially operating contingencies within each Local Capacity Area. These contingencies were measured against these standards described above to determine the minimal amount of capacity need in the Local Capacity Area.

The CAISO conducted this Study using the GE PSLF power flow/stability program.

V. Summary of Preliminary Study Results

A. Humboldt Area

The most critical contingencies for the Humboldt area involve 1) the loss of the Bridgeville-Cottonwood 115 kV line along with one Humboldt Bay Power Plant and 2) the loss of the Humboldt-Trinity 115 kV line along with one Humboldt Bay Power Plant. These multiple contingencies establish the target of 162 MW as the minimum capacity necessary for the Humboldt area.

The transmission tie lines into the area include:

Humboldt-Bridgeville 115 kV line #1
Humboldt-Trinity 115 kV line#1
Willits-Garberville 60 line kV #1
Trinity-Maple Creek 60 kV

The substations that delineate the Humboldt Area are:

- Low Gap 115 kV
- Humboldt 115 kV

[3] These failures include a double circuit tower and the loss of two 500kv lines that are located in the same corridor.

[4] While the CAISO criteria generally allows for load shedding for the N-1, N-2 contingencies, the CAISO also maintains the level of reliability that existed prior to its formation. As such, to the extent a PTO's pre-CAISO standards did not allow for load shedding, the CAISO will also not allow load shedding in that area or corridor.

- Kekawaka 60 kV
- Ridge Cabin 60 kV

B. North Coast / North Bay Area

Eagle Rock pocket
The most critical contingency for the Eagle Rock-Fulton sub-area is described by the loss of the Fulton-Ignacio 230 kV line #1 and the Fulton-Lakeville 230 kV line #1. This limiting contingency requires a minimum capacity of 319 MW within this pocket.

The key transmission facilities coming into this sub-area are:

Fulton-Lakeville 230 kV line #1
Fulton-Ignacio 230kV line #1
Cortina 230/115 kV Transformer #1
Lakeville-Sonoma 115 kV line #1
Corona-Lakeville 115 kV line #1
Willits-Garberville 60 kV line #1

The substations that delineate the Eagle Rock-Fulton sub-area are:

- Fulton 230 kV
- Corona 115 kV
- Sonoma 115 kV
- Cortina 115 kV
- Laytonville 60 kV

Lakeville pocket
The most critical contingency for the Lakeville sub-area would be outages on Vaca-Dixon-Lakeville 230 kV line #1 and the Crockett-Sobrante 230 kV line #1. This limiting contingency requires a minimum capacity of 658 MW within this pocket. The transmission tie lines into this sub-area are:

Vaca Dixon-Lakeville 230 kV line #1
Tulucay-Vaca Dixon 230 kV line #1
Lakeville-Sobrante 230 kV line #1
Ignacio-Sobrante 230 kV line #1
Lakeville-Fulton 230 kV line #1
Lakeville-Corona 115 kV line #1

The substations that delineate the Lakeville sub-area are:

- Lakeville 230 kV
- Ignacio 230 kV
- Tulucay 230 kV
- Lakeville 115 kV

C. Greater Bay Area

The most limiting contingencies within the Greater Bay Area are an over-lapping outage of the Tesla-Metcalf 500 kV line with the Tesla-Newark #1 230 kV line. The amount of generation required within the Greater Bay area is predicated on staying within the emergency rating of the Tesla-Newark #2 230 kV line and specifically that portion of the line consisting of bundled 1113 AL conductor emanating from Newark Substation. This requires 5,435 MWs[5] of generation resources within the Greater Bay area.

Under the CAISO Revised Action Plan for San Francisco, all Potrero generation will continue to be required through 2006.

The substations that delineate the Greater Bay Area are:

- Sobrante 230 kV
- Moraga 230 kV
- Contra Costa Sub 230 kV
- Contra Costa P.P. 230 kV
- Pittsburg 230 kV
- Tesla 230 kV
- Metcalf 500 kV
- Moss Landing 500 kV
- Morgan Hill 115 kV
- Newark 115 kV

D. Sierra Area

The most critical contingencies in the Sierra area are 1) the loss of the Poe-Rio Oso 230 kV line #1 and the Colgate – Rio Oso 230 kV line #1, and 2) the loss of the Cresta-Rio Oso 230 kV line #1 and the Colgate – Rio Oso 230 kV line #1. The minimum capacity needed for the Sierra area is 1730 MW.

[5] This MW amount includes Market and Qualifying Facility generation only at this time. This total does not include the amount of municipal generation that was modeled on-line in the analysis and as such, the total amount of generation required in the Greater Bay Area is 5,435 MW plus the amount of muni generation that was modeled on-line. A tabulation of muni generation was not available for inclusion in this initial overview report.

The transmission tie lines into the Sierra area are:

Table Mt-Rio Oso 230 kV line #1
Rio Oso-Poe 230 kV line #1
Rio Oso-Cresta 230 kV line #1
Gold Hill-Ralston 230 kV line #1
Colgate 230/60 kV Transformer #1
Atlantic 230/60 kV Transformer #1
Gold Hill 230/115 kV Transformer #1
Gold Hill 230/115 kV Transformer #2
Palermo 230/115/60 kV Transformer #1
Caribou-Palermo 115 kV line #1
Bogue-Rio Oso 115 kV line #1
Rio Oso-Nicolaus 115 kV line #1
Pease-Rio Oso 115 kV line #1
Drum-Rio Oso 115 kV line #1
Drum-Rio Oso 115 kV line #2
Drum-Summit 115 kV line #1
Drum-Summit 115 kV line #2
Spaulding-Summit 60 kv line #1
Table Mt-Pease 60 kV line #2

The substations that delineate the Sierra Area are:

- Palermo 230 kV
- Rio Oso 230 kV
- Colgate 230 kV
- Atlantic 230 kV
- Gold Hill 230 kV
- Drum 115 kV
- Caribou 115 kV
- Table Mountain 60 kV
- Tamarack 60 kV

E. Sacramento Area

The critical contingency for the Cortina sub-area is the loss of Wadham Generator #1. This contingency necessitates a minimum capacity of 25 MWs within this pocket. The tie line into this pocket is the Cortina 230/60 kV transformer #1.

The critical contingency for the Davis-West Sacramento sub-area involves the Rio Oso-Woodland 115 kV line #2 and the Davis-Brighton 115kV line #1. This contingency necessitates a minimum capacity of 65 MWs within this pocket. The tie lines coming into this pocket are:

Rio Oso-Woodland 115 kV #1
Rio Oso-Woodland 115 kV #2
Davis-West Sacramento 115 kV #1
Davis-Brighton 115 kV #1

The substations that delineate the Davis-Sacramento sub-area are:

- Woodland 115 kV
- Davis 115 KV

F. Stockton Area

The critical contingency for the Tesla-Bellota sub-area is the loss of Tesla-Tracy 115 kV #1 and Tesla-Safeway 115 kV #1. The capacity needed for the Stockton area is 449 MWs. The transmission facilities that establish the boundary of the Stockton area are:

Bellota 230/115 kV Transformer #1
Bellota 230/115 kV Transformer #2
Tesla 230/115 kV Transformer #1
Tesla 230/115 kV Transformer #3

The substations that delineate the Tesla-Bellota sub-area are:

- Tesla 115 kV
- Bellota 115 kV

G. Greater Fresno Area

The most limiting contingency within the Wilson sub-area is the loss of the Wilson - Melones 230 kV line, which requires 1,560 MWs as a minimum generating capacity within the Wilson pocket to avoid criteria violations. At least 120 MWs of this amount must come from the Helms generating units.

The most limiting contingency within the Herndon sub-area is the loss of the Herndon 230/115 kV bank 1, which requires a minimum of 1,207 MWs generating capacity within the Herndon sub-area to avoid criteria violations.

The most limiting contingency within the McCall sub-area is the loss of Kings River – Sanger – Reedley 115 kV line, which requires a minimum of 1,345 MWs generating capacity within the McCall sub-area to avoid criteria violations.

Within the Henrietta sub-area a minimum 40 MW generating capacity is needed to mitigate the Henrietta 230/70 kV bank overload.

The most limiting contingencies within the Merced sub-area is the double line outage of the Wilson – Atwater 115 kV #1 and #2 lines, the Wilson – Merced 115 kV #1 and #2 lines, which requires a minimum of 172 MWs generating capacity within the Merced sub-area to avoid criteria violations.

The total aggregated generation needed for the Greater Fresno is 2,814 MWs, which comprises a combination of MW requirements from each sub-area.

The transmission facilities coming into the Greater Fresno area are:

Gates-Henrietta Tap 1 230 kV
Gates-Henrietta Tap 2 230 kV
Gates #1 230/115 kV Transformer Bank
Los Banos #3 230/70 Transformer Bank
Los Banos #4 230/70 Transformer Bank
Panoche-Gates #1 230 kV
Panoche-Gates #2 230 kV
Panoche-Coburn 230 kV
Panoche-Moss Landing 230 kV
Panoche-Los Banos #1 230 kV
Panoche-Los Banos #2 230 kV
Panoche-Dos Amigos 230 kV
Warnerville-Wilson 230 kV
Wilson-Melones 230 kV
Corcoran – Alpaugh - Smyrna 115 kV
Coalinga #1-San Miguel 70 kV

The substations that delineate the Greater Fresno area are:

- Los Banos 230 kV
- Gates 230 kV
- Panoche 230 kV
- Wilson 230 kV
- Alpaugh 115 kV
- Coalinga 70 kV

H. Kern Area

For the Kern PP sub-area, the critical contingencies would be outages on the Kern PP 230/115 kV transformer Bank 5 and the Kern PP – Kern Front 115 kV line, which requires a minimum capacity of 771 MW within this load pocket.

For the Weedpatch sub-area, the critical contingencies would be the loss of the Wheeler Ridge – San Bernard 70 kV line and the Wheeler Ridge – Tejon 70 kV line, which requires a minimum capacity of 26 MWs within this load pocket.

The total generation needed for the Kern area is 797 MW.

The transmission facilities coming into the Kern area are:

- Gates – Midway 230 kV line
- Morro Bay – Midway 230 kV lines #1 and #2
- Midway 230/115 kV transformer banks
- Gates – Arco 230 kV line
- Arco 230/70 kV transformer bank
- Smyrna - Semitropic – Midway 115 kV line
- Temblor – San Luis Obispo 115 kV line
- Arco – Cholame 70 kV line

The substations that delineate the Kern Area are:

- Midway 230 kV
- Arco 230 kV
- Smyrna 115 kV
- Temblor 70 kV

I. LA Basin Area

The total market generation requirement for the LA Basin is 5,300 MW.[6]
This total is defined by what is required within the Western sub-area and what is required within the Eastern sub-area.

The most limiting contingency in the Western sub-area is the loss of Vincent - Riohondo 230 kV line #2, followed by loss of Mesa - Vincent 230 kV line which

[6] This MW amount includes Market generation only at this time. This total does not include the amount of Qualifying Facility and municipal generation that was modeled on-line in the analysis and as such, the total amount of generation required for the LA Basin is 5,300 MW plus the amount of muni generation and Qualified Facilities that was modeled on-line.

requires a minimum of 4,450 MWs generating capacity within the Western pocket to resolve criteria violations.

The most critical contingencies in the Eastern sub-area is the loss of Devers – Valley 500 kV line, followed by the loss of two Lugo – Miraloma 230 kV lines #2 and #3. These contingencies would require 850 MWs as the minimum amount of generating capacity needed within the Eastern pocket to resolve criteria violations.

The substation facilities that form the boundaries of the LA Basin are:

- Eldorado
- Devers
- Mirage
- Vincent
- San Onofre
- Sylmar
- Lugo
- Inyo

J. *San Diego Area*

The most limiting contingency in the San Diego area is described by the outage of 500 kV Southwest Power Link (SWPL) between Imperial Valley and Miguel Substations over-lapping with an outage of the new Palomar Combined-Cycle Power plant (542 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MWs. Therefore the 2,620 MWs of capacity required within this area is predicated on having sufficient generation in the San Diego Area to reduce Path 44 to its non-simultaneous rating within 30 minutes.

The transmission tie-lines forming a boundary around San Diego include:

San Onofre - San Luis Rey #1, #2, & #3 230 kV Lines (Path 44 lines)
San Onofre – Talega #1 & #2 230 kV Lines (Path 44 lines)
Imperial Valley – Miguel 500 kV line
Imperial Valley – La Rosita 230 kV line
Imperial Valley – El Centro 230 kV line

The San Diego Area boundary substations impacting the area can be defined by the following sub-stations:

- San Onofre

- San Luis Rey
- Talega
- Imperial Valley
- Miguel

VI. Next Steps

The CAISO encourages stakeholder input and written comments on these preliminary results and the methodology utilized. It would be particularly helpful to receive stakeholder views soon so that stakeholder input and any consensus can be incorporated within the CAISO's comments to CPUC workshop report.

The preliminary results in this study may be refined as the CAISO continues to review its analysis. The CAISO intends to finalize these results through a Final RAR technical study report, currently scheduled for release by July 29, 2005.

If necessary, the CAISO may conduct a possible 2nd deliverability stakeholder meeting on July 20, 2005, to review this study, finalize the results and consider other deliverability issues.

PRELIMINARY DELIVERABILITY BASELINE ANALYSIS STUDY REPORT

California ISO
May 3, 2005

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PRELIMINARY DELIVERABILITY BASELINE ANALYSIS STUDY REPORT

Background

Deliverability is an essential element of any resource adequacy requirement. Specifically, this study assumed deliverability for resource adequacy purposes ensures that the output of a generating unit can reach load under peak conditions. Under the CPUC's resource adequacy proceeding, Load Serving Entities (LSEs) must be able to show that the supplies they intend to procure to meet their load requirements can be delivered to load when needed.

An effective deliverability assessment is essential so that the LSEs will be able to "count" their resources to determine whether they satisfy the California Public Utilities Commission's (CPUC) planning reserve margin[1]. The deliverability assessment in and of itself, however, will not convey any right to deliver electricity to any specific customer or point of delivery. If a deliverability deficiency is identified, then the deliverability of power from some or all generators within the same generation pocket could be reduced.

In 2004 the California Independent System Operator (ISO) proposed an overall deliverability methodology within the CPUC's resource adequacy proceeding to ensure that resources procured by LSE's would be deliverable to load. The complete deliverability proposal consists of three assessments: Deliverability of Generation to the Aggregate of Load, Deliverability of Imports, and Deliverability to Load Within Transmission Constrained Areas which is also known as a locational capacity requirement. The successful implementation of each of these tests is required by the overall deliverability methodology, to ensure that resources procured by LSE's would be deliverable to load.

CPUC Decision (D.) 04-10-035 approved the ISO's proposal to develop the baseline analysis necessary to perform two of the proposed deliverability screens --Generation Deliverability to the aggregate of load and Import Deliverability --that will be used to implement the CPUC's resource adequacy program.

This baseline analysis is also required to implement the Federal Energy Regulatory Commission's (FERC) Order No. 2003. Pursuant to the FERC direction in its order regarding standardization of generator interconnection agreements and procedures, (Order No. 2003), the California Independent System Operator Corporation ("ISO") submitted its Standard Large Generator Interconnection Procedures ("LGIP") for Commission approval and inclusion in the ISO Tariff. In that filing, the ISO proposed that a new Deliverability Assessment be included in the system studies process to help

[1] The Workshop Report on Resource Adequacy Issues included as Attachment A to CPUC Decision 04-10-035 concluded at Page 38 that resources must pass a deliverability test in order to have value in meeting the 90% year-ahead forward commitment requirement.

identify the transmission facilities (Delivery Network Upgrades) that are needed to ensure that the full output of a new Generating Facility may be transmitted to load under peak system conditions. The Deliverability Assessment will define a generic deliverability benchmark to assess the deliverability risk for a given proposed new Generating Facility. It will be modeled after the methodology already approved by the Commission and currently used by PJM (aggregate of generation can be delivered to the aggregate load) and is similar to that prescribed for Network Resources under Order No. 2003.

To initiate this new assessment, the ISO needs to conduct a baseline study to establish the deliverability of existing generating facilities that are connected to the ISO Controlled Grid as well as the total amount of imports on a path by path basis. After this initial assessment is completed, the Deliverability Assessment, as defined in the LGIP, would be performed for each new Generating Facility before it is interconnected to the ISO's grid. It would be performed under peak load and from a resource adequacy perspective to determine if, with the Interconnection Customer's Generating Facility operating at full output, the aggregate of Generation can be delivered to the aggregate of the ISO's Control Area load. The primary objective of this assessment is to determine the incremental impacts on the grid of a new Interconnection Customer's proposed Generating Facility in a consistent and equitable manner.

In anticipation of FERC approval of the ISO's and the Filing Parties' Order No. 2003 compliance filings, and in response to the California Public Utilities Commission ("CPUC") Resource Adequacy Proceeding, the ISO has performed a preliminary baseline deliverability study to determine the deliverability of power from existing Generating Units connected to the ISO Controlled Grid and imports to the aggregate of ISO Control Area load. The ISO requested data at the end of 2004 and began this study at the beginning of 2005. Preliminary results are included in this report for stakeholder review. The Final study report is scheduled to be completed in mid-2005. However, changes to the study methodology, and resolution of policy issues such as the allocation of deliverability problems within a Generation pocket, could impact this schedule.

Once the CPUC's Resource Adequacy Proceeding is completed and FERC approves the ISO's Order No. 2003 compliance filings, the ISO will perform an annual baseline deliverability study. A comparable deliverability study will be performed, on an incremental basis, for each proposed new Generating Facility interconnection.

Appendix 1 provides a description of the baseline deliverability study methodology (Study Methodology). In summary, the ISO baseline deliverability study is a comprehensive test of every generating unit connected to the ISO grid to ensure that there is enough transmission capacity for the power from each generating unit to be delivered to the aggregate of ISO Control Area load. A more detailed discussion of how a generation pocket is defined is included in Appendix 1.

Study Assumptions

Transmission System
A 2006 network model of the ISO Controlled Grid was used for this study. The starting base case was the 2006 ISO Controlled-Grid Summer Peak Base Case, which was updated by the Participating Transmission Owners ("PTO") in January 2005.

Generation
The following generation resource information, as defined in the Resource Adequacy Workshop Report was provided by the generation owners and modeled in the network model for each and every unit in the ISO Control Area that is expected to be commercially operable during summer 2006:

- Net Dependable Capacity during Summer Peak load conditions
- Qualified Capacity during Summer Peak load conditions

Information on how the generation was dispatched in the base case is described in Appendix 1, Study Methodology.

Imports
Import levels in the base case are described in Appendix 1, Study Methodology, and Appendix 2, Initial Import Level. For this baseline assessment, historical import schedule data was used to establish the starting import level to be tested. New import schedules expected as a result of the East of River Short term upgrades were also represented in the analysis.

Load
A 2006, 1 in 5 peak load forecast for the ISO Control Area was modeled in the base case. Individual PTO area load levels were based on an historical diversity factor. A 96% diversity factor was applied to incorporate diversity between the individual PTO area 1 in 5 peak load levels and the overall ISO 1 in 5 peak load level. The 96% factor is the average coincident load factor over six years of historical ISO and PTO, coincident and non-coincident, peak load data.

Contingency Conditions
The PTOs provided electronic files for all NERC Category B and C (excluding C.3 overlapping contingencies) equipment contingencies in their systems, including remedial action and special protection schemes that are expected to be in operations during 2006. These contingencies were simulated during the application of the deliverability methodology.

Study Methodology
Appendix 1, Study Methodology provides a description of the deliverability study methodology. In summary, the ISO baseline deliverability study is a comprehensive test of every Generating Unit to ensure that there is enough transmission capacity for the power from each Generating Unit to be delivered to the aggregate of load. Generating

Units that have a distribution factor "DFAX" (this is defined Appendix 1) of greater than 5% on a facility basis, that is associated with an identified deliverability problem, are considered to be in the same Generation pocket. Generation in a generation pocket is dispatched at its maximum output and transmission facility thermal loadings are monitored to ensure that their applicable ratings are not exceeded with all facilities in-service and following the contingencies described above. Short-term facility ratings listed in the ISO Transmission Register were utilized following contingencies.

Study Tools

The Deliverability Study methodology was implemented using the GE PSLF, GE EPCL, PTI PSSE, and PTI MUST power system software tools. Appendix 3 provides more detail on the Study Tools used for this study.

The 2006 power flow base case was built using the GE PSLF software. This base case was then converted to PTI PSSE format using utilities available with the PTI PSSE software package. The contingency files provided by the PTOs were checked and converted to PTI MUST format using a computer program written in GE EPCL code. The converted base case and contingency files were analyzed using the Generation Sensitivity Analysis feature in the PTI MUST software. The MUST program was used to screen the system for potential deliverability problems. The MUST Generation Sensitivity Analysis feature searches for worst case generation dispatch scenarios that will create overloads and reports these overloads along with the change in generation dispatch and the distribution factors (DFAX) for all generation units with respect to the overloaded facility.

The ISO developed a computer program in GE EPCL code to read this MUST output report and retest the overload scenarios identified by MUST, but in accordance with the Deliverability Study Methodology. Some of the overloads identified by MUST were eliminated because the number units, amount of redispatched MW, or the DFAX of the redispatched units were not in accordance with the Deliverability Study Methodology. Overload scenarios that were confirmed to be within the Deliverability Study Methodology were reported along with all of the generation units significantly contributing to the overload. Units causing the overload are determined per the Methodology and are said to be in the generation pocket.

Identified Issues

Generation Capacity Data

Generation capacity data was provided by 16 different generation owners for most of the 856 generation units modeled in the basecase and assessed in this baseline study. In those instances where unit data was not provided existing generation capacity data already in the WECC basecase was assumed to be the summer peak net dependable capacity. For some units, conflicting capacity data was provided by the generation owner and the generation power purchasing utility, due to their different interpretations of the

Qualifying Capacity definitions in the CPUC's Resource Adequacy Workshop Report. The larger capacity value was tested for such units.

For intermittent generation, Qualifying Capacity data represents an average production over summer peak load hours. In some cases this average capacity value could be deliverable, but production amounts above that average are not deliverable. In this situation the average capacity amount is not a valid qualified capacity value since it could represents level of production that would not be deliverable based on the deliverability methodology. For this study, the capacity data already in the original WECC base case was assumed to be the maximum production during summer peak load hours to ensure that all production values represented by the average capacity would be deliverable. For future studies the ISO recommends that the maximum intermittent generation production data point, included in the calculation of the average production during summer peak for Qualifying Capacity, should be tested in the Deliverability Study. This value is expected to be a more appropriate level for summer peak load conditions than the capacity data entered in the WECC base cases.

Capacity data provided for some units was significantly higher than the capacity data in WECC base cases. It is possible that the capacity amount in excess of the capacity data in WECC base cases was not studied in the original generation interconnection study or subsequent transmission studies. As a result, deliverability issues associated with generation facilities that have capacity values in excess of the WECC base case data should not be attributed to the proposed deliverability methodology, but instead should be attributed to the new generation data.

Transmission Equipment Rating Data
The current ratings for all transmission facilities under the jurisdiction of the ISO are specified in the ISO Transmission Register. For the most part these are the same facility ratings modeled in the baseline base case. However, for facilities with planned terminal equipment upgrades or reconductoring, the higher, planned ratings were modeled.

In addition, some ratings have recently been entered into the ISO Transmission Register, based on a systematic facility review, that are lower than the previously provided facility rating. Since these new ISO Transmission Register Ratings have been entered since the completion of the last annual transmission assessment, they have not been evaluated using traditional transmission assessment methodologies. These derating issues are currently under review by the PTO. Thus, projects to mitigate the effects of the derating are not yet known, but are expected during the next annual transmission expansion planning process. As a result, deliverability issues associated with facilities that have been recently derated should not be attributed to the proposed deliverability methodology.

Study Results

The systematic application of the Deliverability Study Methodology and the new tools used to apply the methodology resulted in identifying powerflow modeling issues.

Because the primary objective of this study is to demonstrate the application of the Deliverability Study Methodology and obtain the necessary approvals for full implementation, many of the data issues were passed on directly to the PTO's to address and are not included in this report. The results provided in this report should be considered preliminary and need to be reviewed when the study methodology is finalized.

Appendix 4 contains tabulated results of the contingency related deliverability issues identified. The results are also briefly summarized below.

NERC Level A: Deliverability issues with all lines in-service

Altamont Wind Generation Area
A 106% overload on the Wind Farms 60 kV line which radially connects 51.3 MW of Altamont wind generation was identified. The ISO has requested for the PTO to review the base case modeling for this system. In addition, accurate generation capacity data for this intermittent generation should be provided to the ISO as discussed above in the Identified Issues section. The magnitude of potential undeliverable wind generation capacity on a Net Dependable Capacity Basis is about 5 MW.

NERC Level B: Deliverability issues associated with single contingencies

North of Lugo Generation Area
A 103% overload on the Lugo-Victor # 1 or 2 230 kV circuit was identified for the outage of the parallel circuit. The rating on this line has recently been reduced and the PTO is currently investigating this problem. The magnitude of potential undeliverable generation capacity is about 85 MW

Tehachapi Generation Area
An overload was identified on two 66 kV lines connecting Tehachapi generation to Goldtown substation. Accurate generation capacity data for this intermittent generation should be provided to the ISO as discussed above in the Identified Issues section in this report. The magnitude of potential undeliverable wind generation capacity on a Net Dependable Capacity Basis is about 100 MW (includes a 35 MW capacity reduction needed to mitigate an overload with all lines in-service).

NERC Level C: Deliverability issues associated with double contingencies

Humboldt Division
One NERC Level C outage results in overloads of 60 kV transmission facilities associated with internal generation in Humboldt area. The magnitude of potential undeliverable generation capacity is about 10 MW.

Sierra Division
Four NERC Level C outages result in overloads on transmission facilities in Sierra area associated with generation located in Sierra, North Valley, and Sacramento areas. Three of these criteria violations have been previously identified in the ISO Transmission

Expansion process and require the development of mitigation plans. The total magnitude of potential undeliverable generation capacity for these contingencies is about 210 MW. The remaining outage results in new overload on transmission facilities in Sierra area, and is a special scenario where reducing the output from generators only is insufficient to reduce power flow on the overloaded facility below its applicable rating.

Diablo Division
One NERC Level C outage results in overloaded transmission facilities. However, similarly to the situation of contingency one in Sierra area, curtailing all generators that have a significant flow impact on the monitored element is not sufficient to mitigate this problem since both local load and generation contribute to the overload.

Kern Division
One NERC Level C outage results in a slight transmission facility overload associated with internal generation in this area. The magnitude of potential undeliverable generation capacity is about 2 MW.

Los Padres Division
One NERC Level C outage in the Los Padres area results in a transmission facility overload. Since both local load and generation contribute to the overload on the facility and the impact from local load is far greater than the generation, curtailing the generators alone is not sufficient to mitigate the overloading conditions.

Fresno Division
One NERC Level C outage results in overloads of 230 kV transmission facilities caused by internal generation in this area even though the existing SPS generation dropping has been included in the study. This criteria violation has been previously identified in the ISO Transmission Expansion Planning process and requires the development of a mitigation plan. The magnitude of potential undeliverable generation capacity is about 716 MW.

Western LA Basin
The emergency ratings for several 230 kV transmission lines in the Western LA Basin have recently been eliminated due to issues identified during a systematic review performed by the PTO. The PTO is currently performing a more detailed review of these lines to develop an action plan. Based on these new ratings, transmission facility overloads were identified that are caused by several generation units in the Western LA Basin during NERC Level C outages. The magnitude of potential undeliverable generation capacity is about 1100 MW.

South Bay/Border 69 kV System
Two NERC Level C outages result in transmission facility overloads caused by generation connected at or near South Bay and Border substations that have significant flow impacts on the 69 kV lines connecting the South Bay, Sweetwater, and Spring Valley substations. The magnitude of potential undeliverable generation capacity is about 180 MW.

Encina-Escondido 138 kV System
Two NERC Level C outages result in transmission facility overloads caused by generation connected at or near Encina substation that have significant flow impacts on the 138 kV lines connecting the Cannon and Shadowridge substations. The magnitude of potential undeliverable generation capacity is about 50 MW.

Deliverability issues to be resolved with existing transmission expansion plans

Devers-Mirage 115 kV System
Several overloads were identified on facilities connected within the 115 kV transmission system network that currently operates in parallel with the 230 kV system connecting Devers and Mirage 230 kV substations, following Level B and C outages. Planned projects in the area will result in splitting the Devers-Mirage 115 kV system into two separate networks that will not be operated in parallel with the 230 kV system. These projects should eliminate the identified overloads, but are not expected to be completed until 2008.

East of Kramer 115 kV System
A 110% overload on the Eldorado- Mt. Pass 115 kV line was identified with all lines in-service. A 103% overload was identified on the same line following a double line outage of both Victor-Kramer 115 kV circuits (a RAS may be installed to mitigate this issue during the interconnection of new generation that was modeled in the area). The magnitude of potential undeliverable generation capacity on a Net Dependable Capacity Basis is about 20 MW. However, the interconnection study for a new generation project that has been modeled in the base case identified a Network Facility upgrade that would mitigate this problem. The status of this Network Facility upgrade is uncertain at this time, so it was not modeled in the base case. Either completing the previously identified Network Facility upgrade or declaring a portion of the new generation project as undeliverable should mitigate this deliverability problem. This deliverability issue should not impact existing generation.

Table 1: Summary of Results

	PG&E	SCE	SDG&E	Total
Number of overloaded facilities	12	11	4	27
Number of contingency causing the overloads	9	11	6	26
Total MW Curtailment	10* Note 1	170** Note 2	160	340

***Note 1: 923 MW of deliverability problems in the PG&E area are related to criteria violations identified in the transmission expansion planning process and**

already require mitigation plans to be developed through that process.

****Note 2: 1100 MW of deliverability problems in SCE area are related to recent transmission line deratings. The revised line ratings will be reflected in SCE's 2005 grid planning assessment. Any identified criteria violations will be addressed as part of that process.**

Conclusions and Recommendations

Approve the Deliverability Study Methodology
The majority of issues identified by this study are not attributable to the application of the proposed Deliverability Study Methodology. This study, using the proposed methodology, confirms that historical summer peak imports and almost all of the existing generation is deliverable. Therefore the proposed Deliverability Study Methodology should be approved for generation interconnection study purposes and for resource adequacy capacity counting purposes.

Identified issues to be investigated further by PTOs
The issues identified by this study should be investigated and resolved by the PTOs.

Interim Period
During an interim period, including but not limited to the study year 2006, all generation should be considered to be deliverable. By a date to be determined, any deliverability issues from this baseline study that affect existing units and imports should be resolved by the PTOs.

Assumptions for next baseline study
The next baseline study will include all new generation projects that have interconnection studies that have been approved by the ISO and will become operational after 2006. The ISO should initiate a Phase II baseline study to assess the deliverability of these generation projects.

Finalize the Qualifying Capacity definitions and update the generation capacity data.
Qualifying Capacity counting definitions should be finalized and generation capacity data should be carefully updated to be consistent with these definitions and reviewed for accuracy. This data should be provided to the ISO using the previously provided template. In addition, for intermittent generation, the maximum and minimum production data points, included in the calculation of the average production during summer peak for Qualifying Capacity should be provided to the ISO for Deliverability Study purposes.

Next Steps

This baseline deliverability study demonstrated the deliverability of all existing generation using the proposed methodology. Once the methodology is approved, these study results need to be reviewed and finalized and a baseline deliverability study looking out five years and evaluating all planned generation projects with approved interconnection studies is needed. This second baseline deliverability study will establish the deliverability of all planned generation projects that have already been processed by existing interconnection study procedures.

Generation and Import Deliverability to the Aggregate of Load (Baseline) Study Methodology Executive Summary

Deliverability is an essential element of any resource adequacy requirement. Specifically, Load Serving Entities (LSEs) must be able to show that the supplies they intend to procure to meet their load requirements can be delivered to load when needed. Otherwise, such resources are of little, if any, value for the purposes of resource adequacy.

An effective deliverability assessment is essential in resource plans so that the LSEs will be able to "count" their resources to determine whether they satisfy the Commission's planning reserve margin. Draft 1 of this paper was the focus of a six-hour meeting and a two-hour conference call involving approximately 30 participants, as well as written comments from eight participants as of April 5th, 2004. The current version of this paper is the result of much stakeholder discussion.

The complete deliverability proposal consists of three assessments: Deliverability of Generation to the Aggregate of Load, Deliverability of Imports, and Deliverability to Load Within Transmission Constrained Areas. Each of these tests would be required for the overall deliverability methodology to ensure that resources procured by LSE's would be deliverable to load. CPUC Decision 04-10-035, requested that the CAISO serve an updated description of the proposed generation and import deliverability to the aggregate of load (Baseline) study methodology, its data requirements, and a schedule for the analysis. Therefore, this paper focuses on the Deliverability of Generation and Imports to the Aggregate of Load portions of the methodology. An implementation of only the generation and import deliverability tests would be an incomplete implementation of the deliverability methodology, and would not adequately ensure deliverability of resources to load.

A. Deliverability Of Generation To The Aggregate Of Load

As part of developing its proposal to comply with FERC's Order No. 2003 regarding the interconnection of new generating facilities, the ISO developed and proposed to FERC a "deliverability" test (but not a requirement). The purpose was to begin to assess the deliverability of new generation to serve load on the ISO's system. Recent experience indicates that while California has added needed new generating capacity to the system over the past few years, not all of that capacity is deliverable to load on the system because of the presence of transmission constraints. Therefore, although not requiring all new generation to be deliverable, the ISO proposed in its Order 2003 compliance filing to assess deliverability so that the sponsors of new generation projects can accurately assess their ability to deliver the output of the new plants to the aggregate of load for resource adequacy counting purposes. This first assessment reflects the deliverability test and the baseline analysis envisioned by the ISO to be conducted as part of this interconnection process.

The ISO recommends that a generating facility deliverability assessment be performed to determine the generating facility's ability to deliver its energy to load on the ISO Controlled Grid under peak load conditions. Such a deliverability assessment will provide necessary information regarding the level of deliverability of such resources with and without Network Upgrades (i.e., major transmission facilities), and thus provide information regarding the required Network Upgrades to enable the generating facility to deliver its full output to load on the ISO Controlled Grid based on specified study assumptions. That is, a generating facility's interconnection should be studied with the ISO Controlled Grid at peak load, under a variety of severely stressed conditions to determine whether, with the generating facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on the ISO Controlled Grid, consistent with the ISO's reliability criteria and procedures. (This definition for deliverability comes from the FERC interconnection order, and this methodology for assessing deliverability has been developed from consultation with PJM officials about their already-established practices.)

In addition, the ISO recommends, based on guidance in FERC Order 2003, that the deliverability of a new resource should be assessed on the same basis as all other existing resources interconnected to the ISO Controlled Grid.

Because a deliverability assessment will focus on the deliverability of generation capacity when the need for capacity is the greatest (*i.e.* peak load conditions), it will not ensure that a particular generation facility will not experience congestion during other operating periods. Therefore, other information (*i.e.* congestion cost analysis for all hours of the year) would be required in addition to the deliverability assessment to evaluate the congestion cost risk of energy purchase agreements, such as a take-or-pay contract with a particular generation facility.

Section I, Generator Deliverability Assessment, contains the technical details of this proposed methodology.

B. Deliverability of Imports

California is now, and will likely remain, dependent on imports to satisfy its energy and resource requirements. Therefore, it is likely that as part of fulfilling their obligation to procure sufficient resources (reserves) in the forward market to serve their respective loads, the IOUs will contract with out-of-state resources. This is appropriate and necessary.

The ability to rely on imports to satisfy reserve requirements is entirely dependent on the *deliverability* of such out-of-state resources to and from the intertie points between the ISO's system and the neighboring systems. While the existing system may be able to satisfy the procurement plans of any one LSE, it likely will not be able to transmit the sum of LSEs' needs. Each LSE may well plan to rely on the same potentially constrained transmission paths to deliver their out-of-state resources. Therefore, the transmission system should be checked to make sure that simultaneous imports can be accommodated.

When relying on imports to serve load, each LSE should be required to ensure that they have assessed the deliverability of such resources from the tie point to load on the ISO's system.

At the CPUC's April 12-13, 2004 Deliverability Workshop, an action item was assigned to the California ISO. As requested, the ISO coordinated a detailed technical discussion and development of a proposal for establishing the total import capacity, for each import path, to be allocated to Load Serving Entities (LSEs) for resource adequacy planning purposes. This proposed approach was presented at the Deliverability Workshop on May 5, 2004.

Transmission constraints can impact the simultaneous deliverability of imports and internal generation. As a result, the interaction between the deliverability of imports and the deliverability of generation needs to be examined. The proposed generation deliverability assessment includes, as an input assumption, the amount of imports and existing transmission contract related encumbrances electrically flowing over the ISO Controlled Grid.

Whatever import capacity is available to LSEs for resource adequacy planning purposes should also be the basis for the import assumptions in the internal generation deliverability analysis. Workshop participants proposed that historical import information should be the basis for determining the initial amount of import levels to be allocated to LSEs. In addition to using historical data, existing transmission contract (ETCs) information should also be utilized. It is assumed that the entities that have contracted for the transmission capacity are already relying on this import capability in their resource plans, so this transmission should not be reallocated.

The impact of these total import levels would likely affect the deliverability of some existing generation, and the interplay between the deliverability of these existing generators and imports needs to be addressed during the generation deliverability analysis. If the deliverability analysis determines that the initial import level assumption is reducing the deliverability of internal ISO grid generation, then the initial import levels would be reduced and the deliverability analysis would be re-run. Although it is not anticipated that import levels would have to be reduced significantly from their initial level based on historical data, this issue may need to be reassessed after the analysis is completed. One of the key benefits of this proposed approach is that a clear deliverability benchmark would be established up front, it would be the starting point for future years, and LSEs would have some flexibility within this structure to adjust their resource adequacy plans to find an appropriate balance between imports and existing generation inside California.

Section II, Deliverability of Imports Assessment, contains the technical details of the deliverability of imports study methodology developed by the subgroup.

D. Summary

Several entities reviewing the "Strawperson" proposal questioned how the ISO might tie together these three suggested "buckets" of Deliverability, and when individual resources might be determined or categorized as "deliverable" based on these proposed tests.

The Generation Deliverability Assessment would be performed in the annual baseline analysis and in every new System Impact Study as part of the generation interconnection process. Resources that pass the deliverability assessment could be counted to meet reserve margin requirements and resources that don't pass could not.

Total import capacity to be allocated for resource adequacy purposes would be an input to the generation deliverability assessments. The deliverability of the total import capacity would be assessed during the initial and annual baseline analyses. LSE's could propose additional imports in their long-term resource plans beyond the amounts allocated and these additional imports would tested using the generator deliverability methodology to ensure that the additional imports do not impact the deliverability of generation that has already passed the generation deliverability test. Once the resource plans are approved, the import assumptions for future generation deliverability assessment would be updated as needed.

The Deliverability to Load test would be performed so that the results would be available during the development of the *long term* resource plans. Solutions for resolving resource deficient load pockets could include the construction of resources needed to meet reserve margin requirements but located in the deficient load pocket to mitigate the deliverability to load deficiency. The construction of resources within the load pocket could be by any developer of generation—a procurement contract with that new generator should ensure that it is actually built.

Section I
Generator Deliverability Assessment

1.0 Introduction

A generator deliverability test is applied to ensure that capacity is not "bottled" from a resource adequacy perspective. This would require that each electrical area be able to accommodate the full output of all of its capacity resources and export, at a minimum, whatever power is not consumed by local loads during periods of peak system load.

Export capabilities at lower load levels can affect the economics of both the system and area generation, but generally they do not affect resource adequacy. Therefore, export capabilities at lower system load levels are not assessed in this deliverability test procedure.

Deliverability, from the perspective of individual generator resources, ensures that, under normal transmission system conditions, if capacity resources are available and called on, their ability to provide energy to the system at peak load will not be limited by the dispatch of other capacity resources in the vicinity. This test does not guarantee that a given resource will be chosen to produce energy at any given system load condition. Rather, its purpose is to demonstrate that the installed capacity in any electrical area can be run simultaneously, at peak load, and that the excess energy above load in that electrical area can be exported to the remainder of the control area, subject to contingency testing.

In short, the test ensures that bottled capacity conditions will not exist at peak load, limiting the availability and usefulness of capacity resources for meeting resource adequacy requirements.

In actual operating conditions energy-only resources may displace capacity resources in the economic dispatch that serves load. This test would demonstrate that the existing and proposed certified capacity in any given electrical area could simultaneously deliver full energy output to the control area.

The electrical regions, from which generation must be deliverable, range from individual buses to all of the generation in the vicinity of the generator under study. The premise of the test is that all capacity in the vicinity of the generator under study is required, hence the remainder of the system is experiencing a significant reduction in available capacity. However, since localized capacity deficiencies should be tested when evaluating deliverability from the load perspective, the dispatch pattern in the remainder of the system is appropriately distributed as proposed in Table 1.

Failure of the generator deliverability test when evaluating a new resource in the System Impact Study brings about the following possible consequences. If the addition of the resource will cause a deliverability deficiency then the resource should not be fully counted towards resource adequacy reserve requirements until transmission system upgrades are completed to correct the deficiency.

A generator that meets this deliverability test may still experience substantial congestion in the local area. To adequately analyze the potential for congestion, various stressed conditions (i.e., besides the system peak load conditions) will be studied as part of the overall System Impact Study for the new generation project. Depending on the results of these other studies, a new generator may wish to fund transmission reinforcements beyond those needed to pass the deliverability test to further mitigate potential congestion—or relocate to a less congested location.

The procedure proposed for testing generator deliverability follows.

2.0 Study Objectives

The goal of the proposed ISO Generator deliverability study methodology is to determine if the aggregate of generators in a given area can be simultaneously transferred to the remainder of ISO Control Area. Any generators requesting interconnection to the ISO Controlled Grid will be analyzed for "deliverability" in order to establish the amount of deliverable capacity to be associated with the resource.

The ISO deliverability test methodology is designed to ensure that facility enhancements and cost responsibilities can be identified in a fair and nondiscriminatory manner.

3.0 Baseline analysis

Deliverability Test Validation: This procedure was derived from the deliverability test procedure currently used by PJM. Adaptations to the PJM procedure were necessary due to the considerable physical differences between the PJM system and the ISO-Controlled Grid. During the initial implementation of this procedure, it will be a tested, and evaluated on existing resources to ensure that the results are reasonable, equitable, and consistent with engineering judgment. Stakeholders will review the results of this validation process. The deliverability test procedure will be refined as needed.

In order to ensure that existing resources can pass this deliverability assessment, an annual baseline analysis, with the most up-to-date system parameters, must first be performed by applying the same methodology described below on the existing transmission system and existing resources. Identified deliverability problems associated with generation that exist prior to the implementation of this deliverability test may be mitigated by transmission expansion projects if the capacity is needed and/or the project is economically justifiable. Deliverability limitations on currently existing generation can be allocated among multiple generators contributing to the same problem by first giving a lower priority to generation that elected to not finance transmission upgrades identified in their interconnection study for deliverability purposes. Then, for units with the same priority, allocation of deliverability limitations would be based on the incremental flow impact that each generator would contribute to the problem. The deliverability of both existing and new generators that are certified as deliverable would be maintained by the annual baseline analysis and the transmission expansion planning process.

4.0 General Procedures and Assumptions

Step 1: Build an initial powerflow base case modeling ISO resources as shown in Table 1. This base case will be used for two purposes: (1) it will be analyzed using a DC transfer capability/contingency analysis tool to screen for potential deliverability problems, (2) it will be used to verify the problems identified during the screening test, using an AC power flow analysis tool. All new generation applicants in the interconnection queue ahead of the unit under study are set at 0 MW but available to be turned on during the analysis. Unused Existing Transmission Contracts (ETC's) crossing control area boundaries will also be modeled as zero MW injections at the tie point, but available to be turned on at remaining contract amounts for screening analysis[1]. Then the capacity resource units in the queue electrically closest to the unit being studied are turned on at an equivalent level to the existing capacity resource until the net ISO Control Area interchange equals the interchange target (see deliverability of imports section). Generation applicants after the queue position under study are not modeled in the analysis.

Step 2: Using the screening tool, the ISO transmission system is essentially analyzed facility by facility to determine if normal or contingency overloads can occur. For each analyzed facility, an electrical circle is drawn which includes all units (including unused ETC injections) that have 5% or greater distribution factor (DFAX) on the facility being analyzed. Then load flow simulations are performed, which study the worst-case combination of generator output within each 5% DFAX circle. The 5% DFAX circle can also be referred to as the Study Area for the particular facility being analyzed.

Step 3: Using an AC power flow analysis tool and post processing software, verify and refine the analysis of the overload scenarios identified in the screening analysis.

The outputs of capacity units in the 5% circle are increased starting with units with the largest impact on the transmission facility. No more than twenty[2] units are increased to their maximum output. In addition, no more than 1500 MW of generation is increased. All remaining generation within the Control Area is proportionally displaced, to maintain a load and resource balance. The number of units to be increased within a local area is limited because the likelihood of all of the units within a local area being available at the same time becomes smaller as the number of units in the local area increases. The amount of generation increased also needs to be limited because decreasing the remaining generation can cause problems that are more closely related to a deficiency in local generation rather than a generation deliverability problem.

[1] For the initial baseline analysis the interchange target is based on historical usage. The East of River upgrades are expected to increase the Palo Verde Branch Group by 500 MW. This 500 MW expected increase in scheduling capability was modeled similar to the Unused Existing Transmission Contracts.

[2] The cumulative availability of twenty units with a 7.5% forced outage rate would be 21%--the ISO proposes that this is a reasonable cutoff that should be consistently applied in the analysis of large study areas with more than 20 units. Hydro units that are operated on a coordinated basis because of the hydrological dependencies should be moved together, even if some of the units are outside the study area, and could result in moving more than 20 units.

For Study Areas where the 20 units with the highest impact on the facility can be increased more than 1500 MW, the impact of the remaining amount of generation to be increased will be considered using a Facility Loading Adder. The Facility Loading Adder is calculated by taking the remaining MW amount available from the 20 units with the highest impact times the DFAX for each unit. An equivalent MW amount of generation with negative DFAXs will also be included in the Facility Loading Adder, up to 20 units. Negative Facility Loading Adders should be set to zero.

Step 4: Verified overloaded facilities with a DFAX from the new unit greater than 5% would need to be mitigated for the new unit to pass the deliverability test.

Table 1: Resource Dispatch Assumptions

Resource Type	Base Case Dispatch	Available to Selectively Increase Output for Stressed-Scenario Dispatch?	Available to Scale Down Output Proportionally with all Control Area Capacity Resources?
Certified Capacity Resources*	80% to 95% of Summer Peak Net Dependable Capacity	Y	Y
Energy Resources*	Minimum commitment and dispatch to balance load and maintain expected imports	N	Y
Intermittent Resources	Minimum production during summer peak load hours	Y	Y
Imports	As determined in deliverability of imports section		
Load			
• Non-pump load	90% to 100% of maximum load.	N	N
• Pump load	Within expected range for Summer peak load hours**.	N	N

* The initial baseline analysis would identify the initial set of Certified Capacity Resources and Energy Resources. See section 3.0 Baseline analysis. All units should be dispatched at the same percentage of their Net Dependable Capacity, but his level may fluctuate to account for differing expectations of system-wide forced outages, retirements, and spinning reserve levels. Some large units with a high likelihood of retirement within the near future may be dispatched at zero to balance loads and resources, but will be available to be turned on during the analysis.

** Summer peak load hours are the 50 to 100 hours in the months of August and September when Control Area load is between 90% and 100% of maximum annual load.

Distribution Factor (DFAX)
Percentage of a particular generation unit's incremental increase in output that flows on a particular transmission line or transformer when the displaced generation is spread proportionally, across all dispatched resources "available to scale down output proportionally with all control area capacity resources in the Control Area", shown in Table 1. Generation units are scaled down in proportion to the dispatch level of the unit.

G-1 Sensitivity
A single generator may be modeled off-line entirely to represent a forced outage of that unit. This is consistent with the ISO Grid Planning Standards that analyze a single transmission circuit outage with one generator already out of service and system adjusted as a NERC level B contingency. System adjustments could include increasing generation outside the study area. The number of generators increased outside the study area should not exceed the number of generators increased inside the study area.

Municipal Units
Treat like all other Capacity Resources unless existing system analysis identifies problems.

Energy Resources
If it is necessary to dispatch Energy Resources to balance load and maintain expected import levels, these units should not contribute to any facility overloads with a DFAX of greater than 5%. Energy Resource units should also not mitigate any overloads with a DFAX of greater than 5%.

WECC Path Ratings
All WECC Path ratings (e.g. Path 15 and Path 26) must be observed during the deliverability test.

Pmax* DFAX Impact
Generators that have a (DFAX*Generation Capacity) > 5% of applicable facility rating or OTC will also be included in the Study Area.

Section II
Deliverability of Imports Assessment

Background

At the CPUC's April 12-13, 2004 Deliverability Workshop, an action item was assigned to the California ISO. As requested, the ISO coordinated a detailed technical discussion and development of a proposal for establishing the total import capacity, for each import path, to be allocated to Load Serving Entities (LSEs) for resource adequacy planning purposes. This proposed approach was presented at the Deliverability Workshop on May 5, 2004.

Transmission constraints can impact the simultaneous deliverability of imports and internal generation. As a result, the interaction between the deliverability of imports and the deliverability of generation needs to be examined. The proposed generation deliverability assessment includes, as an input assumption, the amount of imports and existing transmission contract related encumbrances electrically flowing over the ISO Controlled Grid.

One of the observations from the Workshop was that LSEs needed to have results of the deliverability assessments in advance of submitting their resource plans to the CPUC for the year-ahead review. The generation deliverability assessment would provide results in advance. However, the deliverability of imports assessment initially described was an after-the-fact review of all of the LSE resource plans combined.

Because of the need for up-front information the ALJ assigned the ISO to lead a smaller group of Workshop participants to develop a methodology for determining the total amount of import capacity, by import path, which could be available to LSEs.[3] This document describes a proposal for a methodology developed by the subgroup.

Discussion of Proposed Approach

Whatever import capacity is available to LSEs for resource adequacy planning purposes should also be the basis for the import assumptions in the internal generation deliverability analysis. Because of the interaction between the deliverability of imports and the deliverability of internal generation, one should not simply determine the maximum import capability under favorable conditions and make that import capability available to LSEs for developing their resource plans. This approach assumes that all the import capability is needed and will be used for resource adequacy planning purposes, an assumption that could result in impairment of deliverability of internal generation. (This would be inconsistent with the consensus from previous workshops that the deliverability of generation internal to the ISO grid should be preserved.) Furthermore, it is likely that,

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[3] Determining a methodology for allocating import capability to LSEs was not an assignment of this working group.

compared to a more reasonable import allocation, more of the allocated import capability might remain unused by an LSE to meet its resource adequacy requirement at the expense of more internal generation being available to meet an LSE's resource adequacy requirement.

Workshop participants proposed that historical import information should be the basis for determining the initial amount of import levels to be allocated to LSEs. Following this suggestion, the ISO reviewed actual import flows and schedules during peak load hours in 2003. After initial review of the data, it appears that 2003 saw the highest import levels in the last five years during peak load periods. A subsequent review of 2004 import flows during peak load hours showed similarly high import levels.

In addition to using historical data, existing transmission contract (ETCs) information should also be utilized. It is assumed that the entities that have contracted for the transmission capacity are already relying on this import capability in their resource plans, so this transmission should not be reallocated.

The impact of these total import levels would likely affect the deliverability of some existing generation, and the interplay between the deliverability of these existing generators and imports needs to be addressed. One of the key benefits of this proposed approach is that a clear deliverability benchmark would be established up front, it would be the starting point for future years, and LSEs would have some flexibility within this structure to adjust their resource adequacy plans to find an appropriate balance between imports and existing generation inside California.

Proposed Methodology

Initial Import Level
The proposed approach for combining both historical information and contractual information is to add final transmission net import schedules (day-ahead, hour ahead, and real-time) not associated with ETCs, to ETC reservations on a path by path basis. One could then verify that this sum would not have exceeded the historical Operational Transfer Capabilities (OTCs) and make the appropriate adjustments. This methodology could be applied using several historical high load, high import hours and then taking the average total net import as the initial net import level.

Generation Deliverability Analysis
Using the initial import level as an input assumption, a baseline analysis of the deliverability of generation to the aggregate of load would be performed as described in the Generation Deliverability Assessment Attachment. This benchmarking analysis would establish the deliverability of internal generation.

Make Results of Deliverability Assessment Available for Use
Once the deliverability assessment is completed the results will be provided for use in developing year-ahead LSE resource procurement plans for resource adequacy purposes.[4] The total import capacity, by path, determined to be deliverable would need to be allocated to LSEs using some allocation methodology that has yet to be defined.

(Optional Step) Modify Results of Deliverability Assessment based on Economic Tradeoff between Import Capacity and Internal Generation Capacity
This step assumes that the deliverability of existing resources may not necessarily be preserved, and could be reduced as needed to increase the deliverability of imports, if it is determined that more economic capacity can be obtained from import levels that exceed the total import capability allocated to LSEs. Some sub-group participants had concerns regarding the logistics of implementing this step, and there is no consensus whether or not this step should be included in this general methodology.

Review of Results of Generation and Import Deliverability Assessment Methodology
As part of the initial implementation of this analysis, the test results for generation and import deliverability should be evaluated to ensure they are reasonable, equitable, and consistent with engineering judgment. Stakeholders would help review the reasonableness of these initial test results, and, if necessary, the deliverability test procedure could be refined.

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[4] Operational requirements of the various local areas (i.e., RMR areas) would need to be addressed so LSEs have the necessary information to develop their resource procurement plans. This includes operational requirements such as the amounts and locations of generation needed to be on line and the potential generation retirements that could increase local area requirements. The deliverability to load methodology should focus on these requirements.

Initial CA ISO Import Level for the Deliverability of Imports Assessment

This paper describes how the assumed level of imports would be set for the purpose of the Deliverability Baseline study. The methodology for this Baseline assessment is explained in another document. Generally, historical import schedule data would establish the starting import level to be tested during the Baseline assessment. This data is included in the attached Table 1.

Over the last five years of historical import schedule data during high load periods, the import levels during 2003 and 2004 were the highest, with 2004 slightly higher than 2003. The CAISO proposes to utilize data from both years because the distribution of the total scheduled import across the Branch Groups was significantly different between the years 2003 and 2004. In order to normalize the distribution of the imports across the Branch Groups for the starting import level, import data from both years 2003 and 2004 were included in the data samples used to obtain the starting import level.

Real Time Final Transmission Allocation Results data available on the CA ISO OASIS web site was the primary data source used to obtain import schedule information. However, a few adjustments were made to the OASIS data when comparisons with actual total imports were significantly different from scheduled total imports due to last-minute operational system adjustments that may not have been reflected in the OASIS data.

The sample hours were selected by choosing hours with the highest total import level when peak load was at least 90% of the annual system peak load. Only one hour was chosen from any particular day. Data from August 20, 2003, August 25, 2003, September 7, 2004, and September 8, 2004 was ultimately selected as the sample import data. These four data sets were then averaged to obtain the starting import level shown in Table 1. The ISO has proposed using an average of recent historical data to ensure with an adequate degree of confidence the simultaneous feasibility and reliability of these import levels.

Scheduled Firm Transmission Rights (FTR_BG_SCHD_MW), scheduled Existing Transmission Contracts (ETC_BG_SCHD_MW), and scheduled spot market usage (TRNS_SPOT_MKT_USAGE_MW) were summed to determine the Scheduled Net Interchange for each Branch Group.

The Scheduled Net Interchange will be the target interchange level for the power flow Baseline study base case, for each Branch Group. Scheduled Existing Transmission Contracts were then subtracted from Scheduled Net Interchange values in the import direction to determine the amount of import that could be allocated (Allocatable Import amount) for each Branch Group if no Deliverability issues are identified during the Baseline assessment.

Unused Existing Transmission Contracts (ETC_BG_AVAIL_MW) would also be considered in the Baseline assessment by modeling them as being used when they have a

Distribution Factor of 5% or more on the critical facility for the generation pocket under study.

Total Import Capability is the sum of the Scheduled Existing Transmission Contracts, Allocatable Import amount, and Unused Existing Transmission Contracts, and was checked against the average Operational Transfer Capability (OTC_BG_MW) to ensure that typical OTC values were not exceeded.

Refinement to Methodology

A few stakeholders were concerned that one of the import schedule values for a particular Branch Group could be an abnormally low value due to an abnormal condition occurring during one of the four peak hours selected. In order to address this concern the ISO has applied the following screening test to identify significantly abnormal data for a particular Branch Group.

Two tests were performed on the Branch Group data to screen for significantly abnormal data. The first test was applied to all Branch Groups and the second test was applied to Branch Groups identified in the first test. The first test was based on calculating the average and Standard Deviation for each set of Branch Group data. Then if the minimum Scheduled Net Interchange value for a Branch Group deviated significantly from the average value for that Branch Group then the second test was applied to that Branch Group. It was assumed that the data fit a normal distribution and that 95% of the samples should be within 2 Standard Deviations of the average. Therefore a significant deviation from the average would be at least two Standard Deviations. However, because of the small number of samples a less restrictive test was applied, and a significant deviation from the average was assumed to be a deviation of more than 1.3 Standard Deviations from the average (80% of the samples should be within 1.3 Standard Deviations of the Average).

After applying the first test to each Branch Group, BLYTHE_BG, CFE_BG, and IID-SCE_BG were each flagged for further analysis.

For these three identified Branch Groups, the average value among the hour 17 Scheduled Net Interchange values was calculated between July 1, and September 16 2004. The average value over these larger sample of hours was less than the originally proposed value for the BLYTHE_BG and the CFE_BG, so no adjustments were made to these Branch Groups. However, for the IID-SCE_BG the average over the larger sample of hours was 42 MW higher. Therefore this Scheduled Net Interchange was slightly increased from 330 MW to 372 MW for this Branch Group. The Allocatable Import MW was also slightly increased from 330 MW to 372 MW for this Branch Group.

Table 1

BG Name	BG Import Dir	Import MW	Export MW	Average Net Import MW	Average Import ETC Sched MW	Average Allocatable Import MW	Average Import Unused ETC MW	Average Total Import Capability MW	Average OTC MW
BLYTHE_BG	E-W	166.75	0	167	7	160	0	167	218
CASCADE_BG	N-S	67.25	0	67	0	67	0	67	80
CFE_BG	S-N	73.25	13.5	60	0	60	0	60	800
COI_BG	N-S	3804.75	32.5	3743	1976	1768	595	4338	4338
ELDORADO_BG	E-W	1250.25	145	1105	0	1105	0	1105	1555
ELVTHRLY_BG	W-E	0	734	-734	0	0	0	0	2459
IID-SCE_BG	E-W	449	118.75	372	0	372	0	372	600
IID-SDGE_BG	E-W	2	123.25	-121	0	0	163	163	225
INYO_BG	E-W	0	0	0	0	0	0	0	56
LAUGHLIN_BG	E-W	0	7	-7	0	0	0	0	0
LUGOGONDR_BG	E-W	0	0	0	0	0	0	0	4
LUGOIPPDC_BG	E-W	365.5	0	366	0	366	0	366	370
LUGOMKTPC_BG	E-W	106.25	1.5	105	0	105	0	105	247
LUGOTMONA_BG	E-W	137.5	30	108	0	108	0	108	160
LUGOWSTWG_BG	E-W	58.5	0	59	0	59	0	59	93
MCCULLGH_BG	W-E	32.5	225.5	-193	0	0	316	316	2598
MEAD_BG	E-W	1377	392.25	894	499	396	294	1188	1460
MERCHANT_BG	E-W	325	37.5	288	0	288	0	288	645
N.GILABK4_BG	E-W	3.75	200	-196	0	0	140	140	240
NOB_BG	N-S	1496	0	1496	0	1496	0	1496	1621
PALOVRDE_BG*	E-W	2096.75	37	2060	625	1435	121	2181	2823
PARKER_BG	E-W	81.5	3	79	38	41	53	131	220
RNCHLAKE_BG	E-W	0	760.25	-760	0	0	0	0	1291
SILVERPK_BG	E-W	11.5	12.5	0	0	0	0	0	17
SUMMIT_BG	E-W	12.5	50	0	0	0	0	0	90
SYLMAR-AC_BG	W-E	373	621.75	-249	301	0	674	975	1200
VICTVL_BG	W-E	375.5	0	326	106	220	177	502	1526
Area 22,24,30,99 Interchange				10526					
Total						8043	2532	14125	

Appendix 3: DETAILED STUDY METHODOLOGY

Detailed Study Methodology for Generation Deliverability Study

This document describes the detailed methodology that has been used in the preliminary California ISO generation deliverability study. The document is divided into four main sections covering the main concepts and techniques of the study process. Section 1 explores the generation deliverability concept, technical difficulty while attempting to determine deliverability problems, and the overview of the entire study methodology. Section 2 explains the screening process that filters scenarios with potential deliverability problems from the massive number of scenarios. Section 3 focuses on the verification process which deliverability problems from potential scenarios will be confirmed. At the end of this document, Section 4 concentrates on the study results and explains each section of deliverability report.

1) <u>Overview of Deliverability Study</u>

The basic concept of generation deliverability study is the ability to look for potential transmission planning and operating reliability criteria violations associated with dispatch of generators. The ISO proposed deliverability methodology narrows the scope of the deliverability assessment to scenarios when there is the capacity reserve shortages, which are expected to occur during the summer peak load period. During this time period it is assumed that all available generation would be dispatched to serve load regardless of cost. It is also assumed that there is sufficient generation producing in the load pockets. Instead of looking at several "snapshot" scenarios of the system, deliverability study searches for potential problems among millions of scenarios created by the variation of generation dispatch, contingencies, and limiting facilities. As a result, deliverability study could reveal reliability problems that never been found during the regular planning process. In addition, the methodology for varying the generation must be well defined so it can be consistently applied across the ISO system and from one generator interconnection study to the next, and limited to reasonably expected scenarios. The PJM Deliverability Assessment methodology was used as the starting point for developing the California ISO proposed deliverability methodology.

In general, scenarios for generation deliverability can be created from the combination of the following factors.

- Contingencies: Loss of single or multiple elements according to NERC category B or C outages.
- Generation Dispatch: Any changes in output (increasing or decreasing) of single or multiple generators in the study area that might impact power flow on the facilities.
- Branch Group Flows: Branch Groups represent the transmission paths between California ISO Control Area and the neighboring systems. Branch Group flows in the base case were based on historical imports during summer peak. Existing transmission contracts not scheduled in the base case could be scheduled during the development of stressed scenarios.

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Example of how different scenarios can be created can be demonstrated by looking at a sample 5 buses power system as shown in figure 1. In this example, even though the system has only 5 buses, 4 lines, and 1 transformer, 47 scenarios can be created from combining the following parameters:

- Contingencies only create 15 different scenarios (5 for N-1 and 10 for N-2 common mode failures)
- Generation dispatches only create 2 different scenarios.
- Combination of contingencies and dispatches create 30 different scenarios.

Following the same approach shown in this example, combined events for a full-loop power flow base case will easily reach millions of scenarios. A generation deliverability study needs to analyze these scenarios to search for transmission overloading problems.

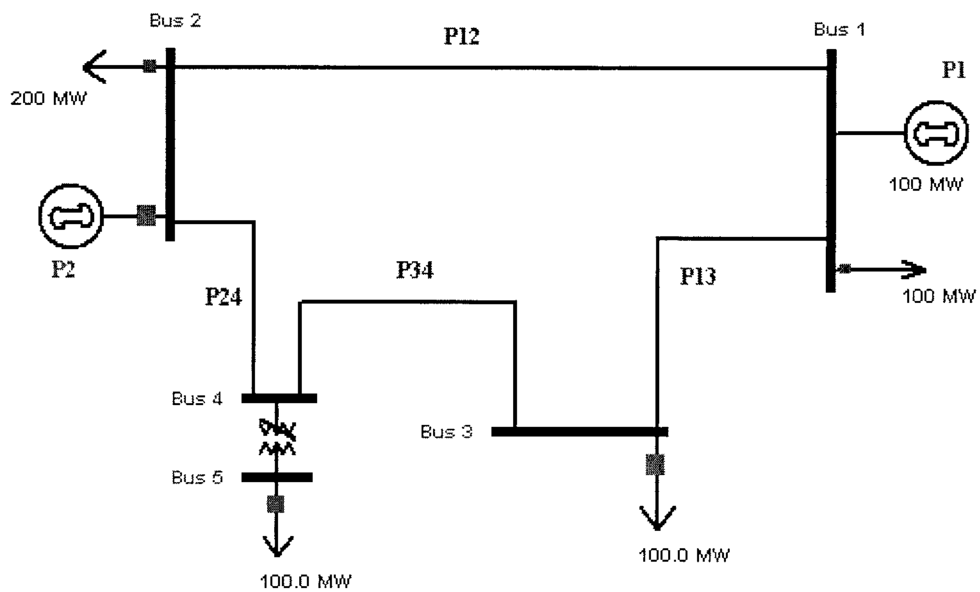

Figure 1. A 5 buses test system

Large numbers of study scenarios make it almost impossible to analyze every case using non-linear AC power flow analysis. For this reason, this deliverability study has adopted a screening technique to select only the scenarios with potential deliverability problem that limit the deliverability of generator capacity from all scenarios with much faster speed[1]. The mechanics behind this screening process is the implementation of linear analysis that does requires repetitive non-linear AC power flow solution for each study scenario. Then the impacts from any changing parameters can be calculated using appropriate distribution factors. More details of the screening process will be covered in section 2.

After the screening process has selected potential scenarios from all scenarios, these scenarios will need to be verified to ensure the existence of deliverability problems. The main

[1] This methodology for assessing deliverability has been developed from consultation with PJM engineers

purpose of this secondary process is to eliminate any mismatches that might occur from adopting the linear analysis technique. During the verification process, AC power flow will be used to confirm deliverability problems in each case as well as other techniques could be implemented to obtain additional useful information. The details of verification process will be discussed in section 3 and the summary of the deliverability study process is shown in figure 2.

As seen from the overview of the study concept, the underlying benefits from this 2-step approach is the ability to identify deliverability problems from massive number of scenarios in much shorter time while the accuracy of results will not be compromised. Since the final determination of deliverability relies on AC power flow, the problems reported by the study will not be based on the approximation technique and will reflect the impact from both real and reactive power flow.

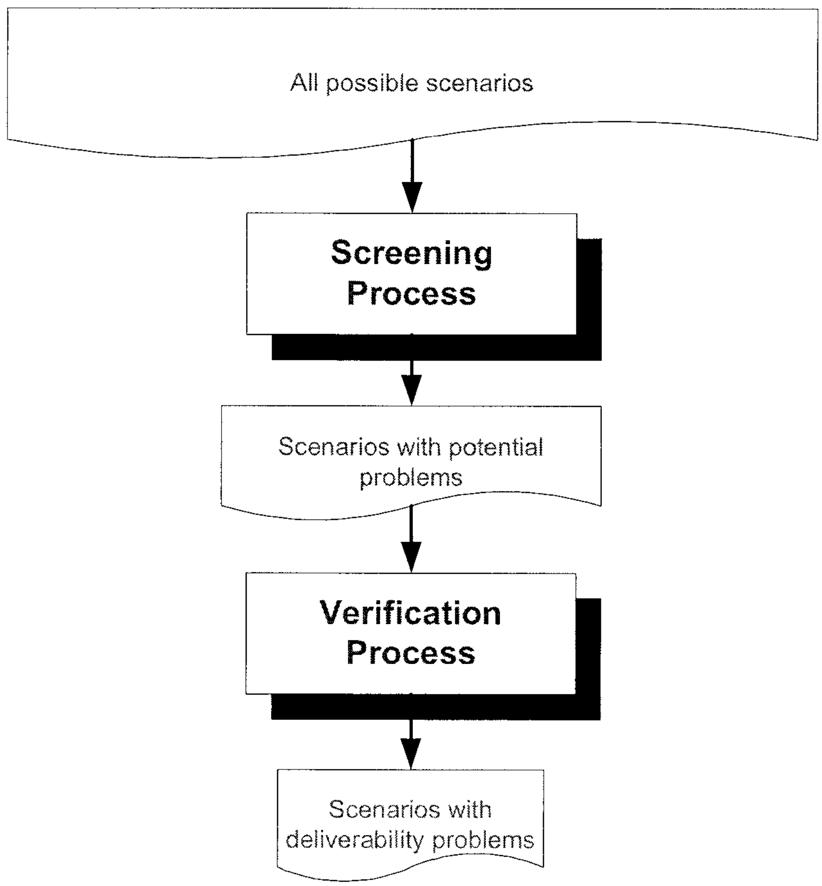

Figure 2. Overview of the deliverability study processes

2) Screening Process

Section 1 of this document has highlighted the importance of the screening process as a key tool to minimize the number of scenarios that will be sent to the verification process. Generally, a good screening process should reject most scenarios that cause no deliverability problems. However, it is imperative that the screening process should not be too sensitive and rejects too many scenarios that might include some scenarios with deliverability problems.

Linear analysis has been used in the screening process. It is an analysis technique well known to power industry for quite sometime. The product such as Transmission Loading Relief (TLR) is an example of linear analysis applications in modern electricity market. In a nutshell, linearization technique assumes that superposition theory can be used and there is no nonlinearity of output in the system. Consequently, regardless of how many scenarios the study has, linearization requires only one non-linear AC power flow solution and distribution factors for future calculations. Then, since the impact on the system is assumed to be linear, the impact on the system can be determined using distribution factors. For example, once the generation shift factor (GSF) of a generator over a transmission line has been calculated, the impact from any level of output from this unit over a transmission line can be estimated without the need to obtain a new power flow solution.

There are a number of distribution factors have been developed for different purposes. This document will focus on three distribution factors related to deliverability study. The basic concept of these factors is explained in section 2.1-2.3[2].

2.1 Generation Shift Factor (GSF)

Generation Shift Factor is a distribution factor that can be used to estimate the impact from the shift of a generator's output over a transmission facility. Basically, GSF determines percentage of the change at generator's output that will appear over the facility. For example, assuming the same 5 buses power system as shown in figure 1. Given $GSF_{2,34}$ is the GSF of the impact from generator at bus 2 over this transmission line 34. The impact from the incremental of output from generator at 2 over this line can be calculated by the following formula.

$$\text{Impact from generator} = (GSF_{2,34})(\Delta P_2) \qquad (1)$$

Where

$GSF_{2,34}$ = Generation Shift Factor of generator at bus 2 over line 34

ΔP_2 = The amount of MW output change from generator at bus 2

This example shows the efficiency of using GSF to estimate power flow on transmission facilities without the need to get a new power flow solution. In this case, once GSFs have been calculated, the impact from any variation of generator output can be obtained from simple arithmetic equations. The same context can be used when focusing on the impact over a transmission line from multiple generators are moving their outputs.

[2] The purpose of these sections is to provide the basic concept of the methodology. The commercial software package may implement different technique to enhance the capability of the program.

2.2 Line Outage Distribution Factor (LODF)

Estimation of impact from an outage over a facility can be done using Line Outage Distribution Factor (LODF). In general, an outage impacts the system by transferring the amount of power flowing on the outaged elements during pre-contingency conditions to other facilities in the system. These changes could increase or decrease power flow on the facilities depending on network topology, load, and generation dispatch.

LODF was formulated as a percentage of pre-contingency flow on the outaged line that appears on the monitoring facility during contingency conditions. Example of the utilization of LODF is shown from considering an example network shown in figure 3. The outage of line 34 will result in the distribution of pre-contingency flow on this line (P_{34}) to the rest of the network. From this example, the impact over line 12 from the outage of line 34 can be calculated from the following formula:

$$\text{Outage Impact} = (LODF_{34,12})(P_{34}) \qquad (2)$$

Where

$LODF_{34,12}$ = LODF over line 12 from the outage of line 34

P_{34} = Power flow over line 34 during pre-contingency conditions

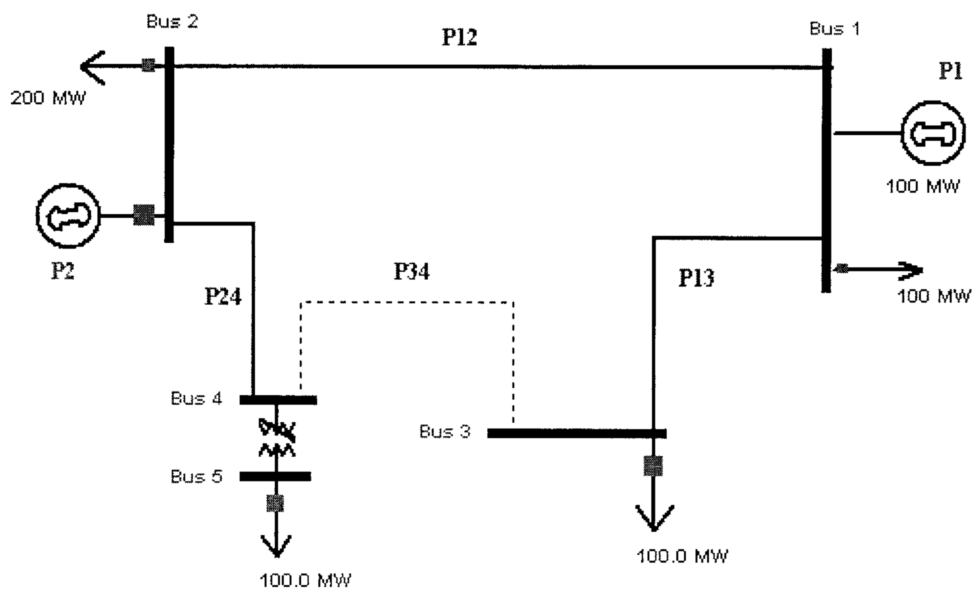

Figure 3: A power system under contingency conditions

2.3 Outage Transfer Distribution Factor (OTDF)

The concepts of GSF and LODF give us an idea of how the impacts from generation dispatch and outage can be estimated without repeatedly obtains new power solutions. However, these two indices do not address the cross-relationship between generator dispatches and outages. This makes the estimation of any scenario involving both contingency and generator dispatch more complicated and becomes a time-consuming process. Example of this scenario is shown in the situation when the contingency of line 34 occurs after generator at bus 2 has increased its output by ΔP_2 MW as shown in figure 4. In this case, incremental output generator 2 will impact power flow not only the line 12 but all lines in the network. Power flow during pre-contingency conditions become P_{12}+($GSF_{2,12}$)(ΔP_2) for line 12 and P_{34}+($GSF_{2,34}$)(ΔP_2) for line 34. Consequently, the estimation of impact from contingency of line 34 using LODF must based on P_{34}+($GSF_{2,34}$)(ΔP_2) instead of P_{34} in order to capture the parallel impact from generation dispatch.

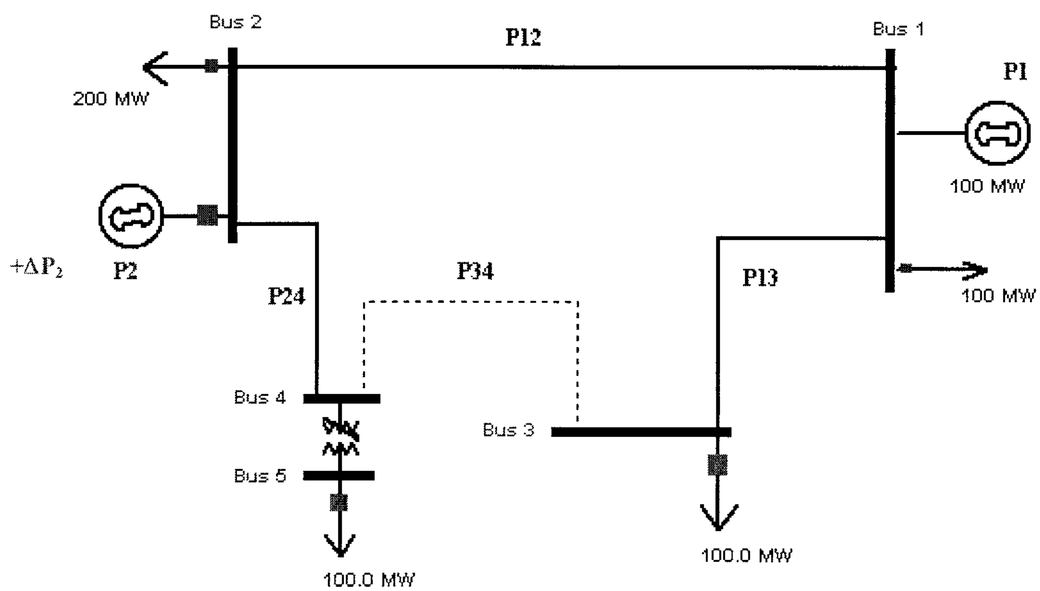

Figure 4: A power system with high generation dispatch under contingency conditions

As seen from this example, the complication of using GSF and LODF has led to the creation of OTDF which represents the combined impact from generation dispatches and outages. Formulation of OTDF was based on GSF and LODF and the impact from the transfer from generator 2 over line 12 under the contingency condition of line 34 can be calculated from equations below.

$$OTDF_{34,12} = \Delta P_2 * [GSF_{2,12} + (LODF_{34,12} * GSF_{2,34})] \quad (3)$$

$$\text{Combined Impact} = (OTDF_{34,12})(\Delta P_2) \quad (4)$$

Where

$OTDF_{34,12}$ = Outage Transfer Distribution Factor on line 12 if line 34 is out-of-service

After the distribution factors become available, it's fairly simple to use these factors to estimate the impact over a facility under various conditions. The basic concept of using the distribution factors is to select the right factor for each scenario. Table 1 shows how different distribution factors should be applied for various scenarios (DFAX is used as a general term to represent to appropriate distribution factor for each scenario).

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Table 1. Selection of distribution factors for different study scenarios

Generators Output[3]	System Conditions	Distribution Factor
Unchanged	Normal	N/A
Changing	Normal	GSF
Unchanged	Contingency	LODF
Changing	Contingency	LODF, OTDF

2.4 Screening Process using Linear Analysis

Section 2.1- 2.3 shows the effectiveness of implementing linear analysis to estimate the impact from any changing parameters as a part of deliverability study. The main benefit of using this method is the significant reduction of computation time for screening process. Generally, millions of scenarios can be screened in the matter of minutes.

California ISO uses the Managing Utilizing System Transmission (MUST) software package for the screening process. The study uses the Generator Sensitivity Analysis (GSA) feature of this software to create all scenarios, calculate DFAX, and identify potential problems. The list below summarizes the MUST user options chosen and some special base case modifications for the deliverability study:

- Ratings of each facility in the base case were scaled to 96% of its base case values. This is necessary to compensate for the overlapping export and import subarea selections used in MUST. This inaccuracy is small because the generation pockets are small compared to the overall ISO system. The 96% derate is expected to overcompensate for the inaccuracy. In addition, the MUST option for reducing line ratings to account for reactive flows was selected. Performing the study with lower ratings is expected to overestimate the known inaccuracies and ensure the reporting of all scenarios with potential deliverability problems.

- Unused existing transmission contracts on Branch Groups were modeled as offline generators available to come on-line, connected to the grid at the control area boundary points. In addition, 1 MW offline generators were modeled on Branch Groups with schedules but fully used existing contracts. This technique allows the program to report branch groups that contributing to deliverability problems. This information will be useful for the future study.

- The study analyzes the system under normal and NERC categories B and C contingencies conditions. It also takes Special Protection Schemes and Remedial Action Scheme into consideration for the accuracy of results.

- In each scenario, only generators with DFAX on the monitored facility greater than 2% were adjusted in the analysis. According to the methodology, the impact from generators with DFAX less or a flow impact (i.e. Pmax*DFAX/facility rating) less than 5% can be considered as minimal and negligible.

- The study searches for potential problems over transmission facilities at the voltage level 60 kV and above.

[3] Assumption of generator's output for the study. Unchanged represents the situation does not involve moving of generator's output. Changing represents the scenarios that vary generator's output that might.

Appendix 3: DETAILED STUDY METHODOLOGY

Applying the above techniques, the screening process selects the scenarios that deliverability problems have been found using the lincar analysis tcchnique. After the screening process is completed, the selected scenarios along with the following information for each case will be provided to the verification process.

- Facilities (transmission lines or transformers) that could encounter deliverability problem.
- Details of the contingency that cause deliverability problem (in case that the problem involves contingency).
- Details of Special Protection Scheme and Remedial Action Scheme (if applicable to the contingency).
- Distribution factors of all units that impact the limiting facilities. This includes the units that exacerbate or relieve deliverability problems.

The figure 5 below shows the overview of screening process.

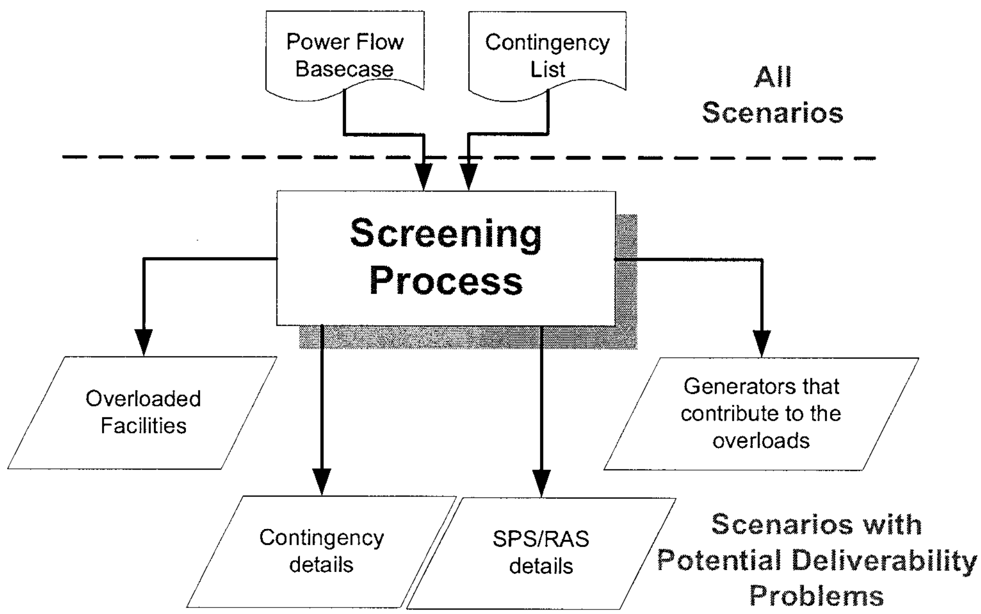

Figure 5 Summary of the Screening Process

3) <u>Verification Process</u>

The verification process is the final step of deliverability study. It was designed to confirm deliverability problems from scenarios that have been found during the screening process. Since the screening technique employs linear analysis technique to speed up the calculation with reduced facility ratings, this process has tendency to overestimate the overloads. For this reason, all the results from the screening process are verified by AC power flow at 100% facility ratings to ensure the deliverability problems are credible. In brief, the main purpose of this process is to ensure the accuracy of study results and to apply the specific ISO Deliverability Methodology to the set of scenarios identified by MUST. Summary of the verification process is shown in figure 6.

Appendix 3: DETAILED STUDY METHODOLOGY

During the course of the study, California ISO has developed an EPCL program MUST.P as the main engine for the verification process. This software automatically reads information from screening process, performs all verification process, and has an ability to perform additional study such as generation capacity reduction. The outputs from this software are given in full text report and/or the database formats that supports easy data manipulation and better future references. Since this EPCL has simulated all the techniques for verification process, this section will be dedicated to explaining the mechanisms behind this program.

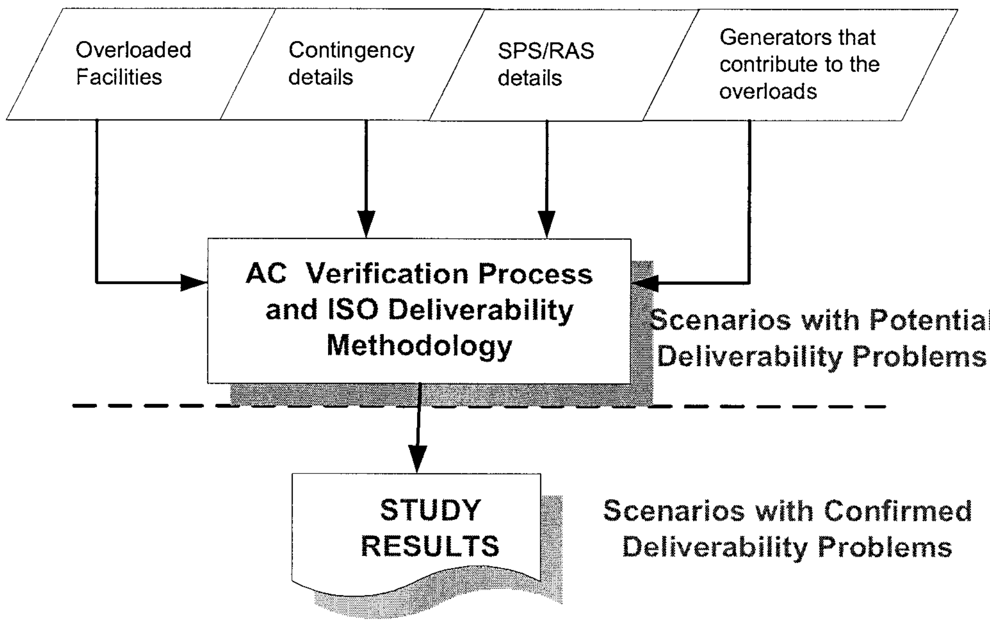

Figure 6. Summary of the verification process

3.1 Simulating Stressed Generation Dispatch Scenarios

The outputs of units with a DFAX or a flow impact ratio greater than 5% are increased starting with units with the largest flow impact on the transmission facility. The flow impact is defined as the DFAX * (Pmax) and the flow impact ratio is the ratio of the flow impact divided by the rating of the facility. No more than twenty[4] units are increased to their maximum output. In addition, no more than 1500 MW of generation is increased. All remaining generation within the Control Area is proportionally displaced, to maintain a load and resource balance. The number of units to be increased within a local area is limited because the likelihood of all of the units within a local area being available at the same time becomes smaller as the number of units in the local area increases. The amount of generation increased also needs to be limited because decreasing the remaining generation can cause problems that are more closely related to a deficiency in local generation rather than a generation deliverability problem.

[4] The cumulative availability of twenty units with a 7.5% forced outage rate would be 21%--the ISO proposes that this is a reasonable cutoff that should be consistently applied in the analysis of large study areas with more than 20 units.

Appendix 3: DETAILED STUDY METHODOLOGY

For study areas where the 20 units with the highest impact on the facility can be increased more than 1500 MW, the impact of the remaining amount of generation to be increased will be considered using a Facility Loading Adder. The Facility Loading Adder is calculated by taking the remaining MW amount available from the 20 units with the highest impact times the DFAX for each unit. An equivalent MW amount of generation with negative DFAXs will also be included in the Facility Loading Adder, up to 20 units. Negative Facility Loading Adders are set to zero. Example of Facility Loading Adder is shown in figure 7.

3.2 Simulating Contingency

After reading all information from screening process, MUST.P simulates contingency by switching the status of transmission facilities or generators. The contingency list (obtained from PTOs) contains NERC category B or C contingencies that involve the outages of single or multiple facilities in the system. However, the program will skip this step if the screening process indicates deliverability problems under normal conditions.

3.3 Simulating SPS and RAS

If a contingency activates an existing or planned Special Protection System or Remedial Action Scheme, this scheme will be simulated during the verification process. The actions taken by these schemes might involve tripping single or multiple transmission facilities, generators or dropping the load.

3.4 Re-dispatching Generators During Contingencies

Generators will be re-dispatched during contingencies if the contingency includes generation or load tripping or if losses change more than a certain amount. This re-dispatch is based on simplified version of the WECC governor power flow methodology to generators in WECC area. This scheme is used to rebalance the power after the outages of generators and/or load caused by contingencies or remedial actions (RAS/SPS). The outaged MW will be distributed to all generators in WECC. The program re-dispatch is based on WECC area response factors observed during a detailed WECC governor powerflow simulation.

```
116 WORST GENERATION CHANGE
117 ------------------------------------
118  NO   BUS     NAME     ID     DF       DF*Pmax/ERate  DF*(Pgmax-Pgold)  Pg(Old)  St(Old)   Pg(New)  St(New)  Pg(chng)
119   1 *10000 GEN A       1   -0.1226     -0.0577        -76.7476          0.00      0        626.00    1        626.00 BG
120   2 *10001 GEN B       1   -0.2185     -0.0268        -35.6155          0.00      0        163.00    1        163.00 BG
121   3 *10002 GEN C       1   -0.1953     -0.0206        -27.3420          0.00      0        140.00    1        140.00 BG
122   4 *10003 GEN D       1   -0.0550     -0.0122        -16.1708          0.00      0        294.00    1        294.00 BG
123   5 *10004 GEN E       1   -0.0508     -0.0121        -14.0716          0.00      0        277.00    1        277.00 BG
124               Total                                  -169.9467          0.00              1500.00             1500.00
125
126 Facility Loading Adder Activated. Remaining units (top 20)
127  NO   BUS      NAME     ID     DF       DF*Pmax/ERate  DF*(Pgmax-Pgold)  Pg(Old)  St(Old)   Pg(New)   St(New)   Pg(chng)
128   5 *10004   GEN E      1   -0.0508     -0.0121         -1.9812         277.00     1        316.00      1         39.00
129   6  90001   GEN F      1   -0.2790     -0.0649        -14.5954         237.69     1        290.00      1         52.31
130   7  90002   GEN G      1   -0.2790     -0.0336         -8.0526         133.14     1        160.00      1         26.86
131   8  90003   GEN H      1   -0.2790     -0.0336         -8.0526         133.14     1        160.00      1         26.86
132   9  90004   GEN I      1   -0.2790     -0.0336         -8.0526         133.14     1        160.00      1         26.86
133  10  90005   GEN J      1   -0.2790     -0.0315         -7.5494         132.94     1        160.00      1         27.06
134  11  90006   GEN K      1   -0.2790     -0.0336         -7.4462         133.31     1        160.00      1         26.69
135  12 *90007   GEN L      1   -0.0808     -0.0035         -4.7864         133.31     0         53.00      0         53.00 BG
136  13 *90008   GEN M      1   -0.1049     -0.0001         -0.1049         133.31     0          1.00      0          1.00 BG
137  14 *90009   GEN N      1   -0.0706     -0.0001         -0.0706         133.31     0          1.00      0          1.00 BG
138  15 *90010   GEN O      1   -0.0530     -0.0000         -0.0530         133.31     0          1.00      0          1.00 BG
139  16 *90011   GEN P      1   -0.0501     -0.0000         -0.0501         133.31     0          1.00      0          1.00 BG
140               Total                                  -60.7151         887.35              1453.00             230.65
141
142 Facility Loading Adder Activated. Equivalent amount of "positive" DFAX units with highest potential impact
143  NO   BUS      NAME     ID     DF       DF*Pmax/ERate  DF*(Pgmax-Pgold)  Pg(Old)  St(Old)   Pg(New)   St(New)   Pg(chng)
144   1  00100   GEN X      2    0.1288      0.0000         25.7454         933.86     1       1115.00      1        201.14
145   2  00101   GEN X      3    0.1066      0.0000          0.5774         885.67     1        993.18      1         87.51
146               Total                                   26.3230        1819.53              2108.18             288.65
147
148   16 Units were scaled to their P Max and assigned zone 986
149   16 Units were added to RTR 0 986
150
151 Redistributes Zone 987 by 1500.00 MW to compensate for transfer
152          New Pgen at Swing bus is  862.05 MW  Basecase has  804.39  MW     Redispatch  -57.66 MW again
153          New Pgen at Swing bus is  799.19 MW  Deviation less than  10 MW... Proceed to the next step
154
155 CASE SOLVED   Largest Mismatch =   0.07 at   14221 WESTWING  230.00    Slack NAVAJO  =  799.19 MW
156
157 Contingency flow  -1393.64 MW   -1.82 MVAR 3521.38 Amps = 105.12% of 1329.00 MVA  E Rating   Swing = 799.19
158 Contingency flow from Facility Loading Adder:    1428.04 MVA = 107.72% of 1329.00 MVA  E Rating  Swing =  799.19 MW
```

Figure 7. Example from Facility Loading Adder

The example seen in figure 7 shows Facility Loading Adder (FLA) is activated when the accumulated output from generators exceeds 1,500 MW (up to the point where generator E is dispatching at 277 MW). The impact from moving 1,500 MW resulting in 105.12% loading on the monitored element as seen in line 157. The estimated impact from FLA is calculated by:

- Adding the impact from the remaining generators in the top 20 (line 140).
  New flow = -1393.64 + (-60.7151) = -1454.35 MVA

- Deducting the impact from the dispatch of units with opposite DFAX (balancing)
  New flow = -1454.35 + 26.3230 = -1428.04 MVA

As seen from line 158, power flow from FLA is estimated at –1428.04 MVA or 107.72% of facility rating.

3.5 Generation Capacity Reduction

Generation Capacity Reduction (GCR) is an optional process used to quantify the MW curtailment from generators. It calculates the amount of undeliverable MW of generators based on their contribution to the problem, to ensure that power flow on the monitored facility will not exceed its applicable ratings. At this point, the ISO has included an interim version of GCR scheme in the verification process as a guideline of how the calculation could be done and to access the magnitude of undeliverable MW in the preliminary study. The final methodology for GCR would be determined based on the input from stakeholder process.

Appendix 3: DETAILED STUDY METHODOLOGY

4) <u>Generation Deliverability Results</u>

This section explains the results that will be given in the report created by MUST.P. For each deliverability problem, MUST.P program produces a detailed report describing the problems as shown in figure 8-9. This report can be divided into 7 parts as follow.

1) Monitored facility and power flow on this facility under normal conditions
2) Contingency with the details.
3) Power flow on the monitored facility after contingency with the base case dispatch. If the contingency involves generator dropping, this will represent power flow after the re-dispatching scheme has been done.
4) Stressed generation dispatch shows up to 20 units with adverse impact on the monitored facility (line 119-123). In some cases, this list may show the units with opposite distribution factors from power flow on the monitored line. In this situation, the study has found a deliverability problem that caused by the stressed dispatch that reverses power flow on the monitored facility. The example in figure 8 also shows the scenario when Facility Loading Adder was activated (line 127-146)
5) Summary of units that pass the screening process and units that were included in the worst dispatch. RTR 986 is assigned to units that significantly impact power flow on the monitored facility based on the screening criteria specified in the straw proposal (5% DAFX).

   Zone 986 represents the units in the top 20 that create worst dispatch. The number of units assigned to zone 986 is always less or equal to units with RTR =.986.
6) Summary of final re-dispatching scheme after moving the generators
7) Reports of final power flow on the monitored facility after all processes have been done.
8) Optional and based on the tentative approach: The reports show generation capacity reduction as shown in figure 9.

When looking at the deliverability report, it is imperative to understand that it simulates the scenarios where contingency has occurred in the system with the generators already producing their output at the stressed dispatch scenario. Result shown in figure 8 is a good example of how generation dispatch can cause reliability problem that cannot be seen simply by applying contingency. The outage itself will not result in reliability problem except exacerbating by the stressed generation dispatch.

```
MONITOR
-------
31000 BUS A  60.00 kV to 31001 BUS B  60.00 kV CCT 1    Zone:399   Area: 30 PG&E     1

Normal flow:     12.20 MW  -7.40 MVar  130.78 Amps = 52.27% of  26.00 MVA  N Rating     Swing =  804.39 MW

CONTINGENCY   10 10)
--------------------
Trip the Line From: 31888 BUS X   115.0 kV 2 To: 31889 BUS Y 115.0 kV  Ckt 1
        New Pgen at Swing bus is  806.06 MW  Deviation less than  10 MW...Proceed to the next step

Contingency flow : 3 21.41 MW  -11.08 MVAR   24.11 MVA = 88.60% of  26.00 MVA  E Rating  Swing = 806.06 MW

WORST GENERATION CHANGE
-----------------------
```

NO	BUS	NAME	ID	DF	DF*Pmx/ERate	DF*(Pgnew-Pgold)	Pg(Old)	St(Old)	Pg(New)	St(New)	Pg(chng)
1	30001	GEN A	1	0.3065	0.6248	2.9304	43.44	1	53.00	1	9.56
2	30002	GEN B	1	0.3065	0.6130	2.8751	42.62	1	52.00	1	9.38
3	30003	GEN C	1	0.2773	0.2666	1.2506	20.49	1	25.00	1	4.51
4	30004	GEN D	1	0.4950	0.4760	1.1252	10.23	1	12.50	1	2.27
5	30004	GEN D	2	0.4950	0.4760	1.1252	10.23	1	12.50	1	2.27
6	30005	GEN E	2	0.2563	4 0.2957	0.8775	11.58	1	15.00	1	3.42
7	30005	GEN E	1	0.2563	0.2957	0.8775	11.58	1	15.00	1	3.42
8	30006	GEN F	1	0.2773	0.1834	0.8604	14.10	1	17.20	1	3.10
9	30007	GEN G	2	0.1643	0.0322	0.1901	3.64	1	4.80	1	1.16
10	30008	GEN H	1	0.1225	0.0038	0.0980	0.00	1	0.80	1	0.80
11	30007	GEN G	1	0.1643	0.0322	0.0493	0.00	1	0.30	1	0.30
		Total				12.2591	167.90		208.10		40.20

```
 11 Units were scaled to their P Max and assigned zone 986
 13 Units were added to RTR 0.986
                Islanded units in Zone 986  5   ....    0
                Units tripped                   ....    0
                Effective Units with 0 Part Factor ....  2

Redistributes Zone 987 by    40.20 MW to compensate for transfer
        New Pgen at Swing bus is  819.79 MW  Basecase has  804.39  MW      Redispatch  -15.41 MW again
      6 New Pgen at Swing bus is  803.47 MW  Deviation less than  10 MW...Proceed to the next step

CASE SOLVED:  Largest Mismatch =   0.06 at  14585 WESTWG 4  100.00    Slack NAVAJO  =  803.47 MW

Contingency flow:    32.75 MW  -15.99 MVAR  335.42 Amps = 134.07% of   26.00 MVA  E Rating   Swing = 803.47  7

Monitored facility is overloaded after the worst dispatch.. Activate Generation Capacity Reduction
```

Figure 8. Example of deliverability main report

```
GENERATION CAPACITY REDUCTION

***** Only merchant units impact the facility. Curtail merchant units only *****

 Curtail   26.91 MW to reduce    8.86 MW flow   New flow:   23.23 MW  252.68 Amps = 101.00% ERate
        Flow is within  1.00% deviation from facility rating..Continue

CURTAILED GENERATION DISPATCH
-----------------------------
```

NO	BUS	NAME	ID	DF	DF*Pmx/ERate	CAPACITY	MX_IMPCT	NRMLZ_IMPCT	IMPCT_REDCTN	CURTL	QLFY_CAP	NOTE	ZONE
1	30001	GEN A	1	0.3065	0.6248	53.00	16.24	0.2504	2.07	6.74	46.26		301
2	30002	GEN B	1	0.3065	0.6130	52.00	15.94	0.2456	2.03	6.61	45.39		301
3	30003	GEN C	1	0.2773	0.2666	25.00	6.93	0.1068	0.80	2.88	22.12		301
4	30004	GEN D	1	0.4950	0.4760 8	12.50	6.19	0.0954	1.27	2.57	9.93		301
5	30004	GEN D	2	0.4950	0.4760	12.50	6.19	0.0954	1.27	2.57	9.93		301
6	30005	GEN E	2	0.2563	0.2957	15.00	3.84	0.0593	0.41	1.59	13.41		301
7	30005	GEN E	1	0.2563	0.2957	15.00	3.84	0.0593	0.41	1.59	13.41		301
8	30006	GEN F	1	0.2773	0.1834	17.20	4.77	0.0735	0.55	1.98	15.22		301
9	30007	GEN G	2	0.1643	0.0322	4.80	0.79	0.0122	0.05	0.33	4.47		303
10	30008	GEN H	1	0.1225	0.0038	0.80	0.10	0.0015	0.00	0.04	0.76		303
11	30007	GEN G	1	0.1643	0.0322	0.30	0.05	0.0008	0.00	0.02	0.28		303
12	30009	GEN I	1	0.1225	0.0000	0.00	0.00	0.0000	0.00	0.00	0.00		303
13	30010	GEN J	1	0.2773	0.0000	0.00	0.00	0.0000	0.00	0.00	0.00		301
		Total				208.10	64.88	1.0000	8.86	26.91			

```
Move 13 Units to Zone 985
```

Figure 9. Example of deliverability report-generation capacity reduction

Appendix 4
PRELIMINARY DELIVERABILITY BASELINE ANALYSIS STUDY REPORT

HUMBOLDT

No	Limiting Facility	PCT Overload	Contingency	Cont No	Type	Curtailment (MW)
1	Humboldt Bay-Humboldt 60 kV line #1	108.91	Humboldt Bay-Humboldt 60 kV line #2 Humboldt Bay-Humboldt 115 kV line #1	38	C	7.51
2	Eureka - Humboldt Bay 60 kV line #1	101.91				2.19
			Total Curtailment			7.51

SIERRA

No	Limiting Facility	PCT Overload	Contingency	Cont No	Type	Curtailment (MW)
1	Bangor - Colgate 60 kV line #1	152.98	Palermo-Colgate 230 kV line #1 Colgate-Rio Oso 230 kV line #1 Colgate PP #1 and #2	409	C	Insufficient
2	Chicago Park - Higgins 115 kV #1	117.79	Rio Oso-Atlantic 230 kV line #1 Rio Oso-Goldhill 230 kV line #1	652	C	89.16
3	Higgins - Bell 115 kV line #1	100.27				1.37
4	Drum - Dutch Flat 115 kV #1	117.13				75.39
5	Drum - Dutch Flat 115 kV #1	101.8	Atlantic-Goldhill 230 kV line #1 Rio Oso-Goldhill 230 kV line #1	657	C	7.91
6	East Nicholas - Rio Oso 115 kV line #1	108.1	Colgate-Rio Oso 230 kV line #1 Table Mt - Rio Oso 230 kV line #1 Colgate PP #1	655	C	109.45
			Total Curtailment			210.06

KERN

No	Limiting Facility	PCT Overload	Contingency	Cont No	Type	Curtailment (MW)
1	Taft 115/70 kV Bank #2	103.21	Midway-Taft 115 kV line #1 and Fellows-Taft 115 kV line #1	1889	C	2.19
			Total Curtailment			2.19

Appendix 4
PRELIMINARY DELIVERABILITY BASELINE ANALYSIS STUDY REPORT

FRESNO

No	Limiting Facility	PCT Overload	Contingency	Cont No	Type	Curtailment (MW)
1	Gregg - Figarden Tap2 230 kV line #1	154.63	Gregg-Herndon 230 kV line #1 and #2	1692	C	716.02
2	Figarden Tap2 - Ashlan 230 kV line #1	143.11				565.11
			Total Curtailment			716.04

LOS PADRES

No	Limiting Facility	PCT Overload	Contingency	Cont No	Type	Curtailment (MW)
1	Morro Bay 230/115 kV Bank #6	154.63	Morro Bay-Mesa 230 kV line #1 and Morro Bay-Diablo 230 kV line #1	2510	C	Insufficient
			Total Curtailment			

DIABLO

No	Limiting Facility	PCT Overload	Contingency	Cont No	Type	Curtailment (MW)
1	Pittsburg-Clayton 115 kV line #1	126.97	Pittsburg-Clayton 115 kV line #3 and #4	944	C	Insufficient
			Total Curtailment			

Western LA Basin

Estimated Gen Reduction to alleviate overloads = 1100 MW

Limiting Facility						Contingency				Type
From Name	To Name	kV	ckt	PCT Overload	Cont. No.	From Name	To Name	kV	ckt	
ALMITOSE	CENTER S	230	1	117	228	ALMITOSE	BARRE	230	1	C
					228	ALMITOSW	LITEHIPE	230	1	
ALMITOSE	BARRE	230	1	103	233	ALMITOSE	CENTER S	230	1	C
					233	ALMITOSW	LITEHIPE	230	1	
HINSON	LITEHIPE	230	1	119	287	LA FRESA	REDONDO	230	1	C
					287	LA FRESA	REDONDO	230	2	
LA FRESA	REDONDO	230	2	124	272	LA FRESA	REDONDO	230	1	C
					272	LITEHIPE	REDONDO	230	1	
LA FRESA	REDONDO	230	1	124	273	LA FRESA	REDONDO	230	2	C
					273	LITEHIPE	REDONDO	230	1	

East of Kramer 115 kV System

Estimated Gen Reduction to alleviate overloads* = 20 MW

Limiting Facility						Contingency				Type
ELDORDO	MTN PASS	115	1	103	31	VICTOR	KRAMER	115	1	C
					31	TAP601	KRAMER	115	1	
					31	VICTOR	TAP601	115	1	
					31	ROADWAY	TAP601	115	1	

* Includes 20 MW reduction required to mitigate overload with all lines in-service.

* A planned RAS may eliminate contingency overload.

Tehachapi

Estimated Gen Reduction to alleviate overloads* = 100 MW

Limiting Facility						Contingency				Type
GOLDTOWN	TAP 74	66	1		506	ANTELOPE	CALCMENT	66	1	B
LANCSTR	GOLDTOWN	66	1							

* Includes 35 MW reduction required to mitigate overload with all lines in-service.

North of Lugo

Estimated Gen Reduction to alleviate overloads = 85 MW

Limiting Facility						Contingency				Type
LUGO	VICTOR	230	2	104	6	LUGO	VICTOR	230	1	B
LUGO	VICTOR	230	1	104	7	LUGO	VICTOR	230	2	B
LUGO	VICTOR	230	1	106	28	LUGO	KRAMER	230	1	C
				106	28	LUGO	KRAMER	230	2	
				106	28	KRAMER	LUZ LSP	230	1	
				106	28	KRAMER	BLM WEST	230	1	

Encina-Escondido 138 kV System

Estimated Gen Reduction to alleviate overloads = 50 MW

Limiting Facility						Contingency				Type
From Name	To Name	kV	ckt	PCT Overload	Cont. No.	From Name	To Name	kV	ckt	
CALAVRTP	CANNON	138	1	103	175	SANLUSRY	SANLUSRY	230	1	C
					175	SANLUSRY	SANLUSRY	230	2	
					175	CRSTNTS	TALEGATP	69	1	
					175	JAP MESA	TALEGATP	69	1	
					175	TALEGA	TALEGATP	69	1	
CALAVRTP	SHADOWR	138	1	106	359	ESCNDIDO	EPP	230	1	C
					359	ENCINATP	ENCINA	230	1	
					359	ENCINATP	SANLUSRY	230	1	
					359	ENCINATP	ESCNDIDO	230	1	
CALAVRTP	CANNON	138	1	108	415	NORTHCTY	PENSQTOS	138	1	C
CALAVRTP	SHADOWR	138	1	104	415	BATIQTOS	BATIQTP	138	1	
					415	BATIQTP	PENSQTOS	138	1	
					415	BATIQTP	ENCINA	138	1	

South Bay/Border 69 kV System

Estimated Gen Reduction to alleviate overloads = 110 MW

CHOLLAS	SPRNGVLY	69	1	101	423	JAMACHA	MIGUEL	69	1	C
					423	JAMACHA	MIGUEL	69	2	
SOUTHBAY	SWEETWTR	69	1	126	347	MONTGMRY	SOUTHBAY	69	1	C
					347	OTAY	SOUTHBAY	69	2	
					347	MONTGYTP	SOUTHBAY	69	1	

CERTIFICATE OF SERVICE

I hereby certify that I have served, by electronic and United States mail, a copy of the foregoing Opening Comments of the California Independent System Operator Corporation on the Resource Adequacy Phase 2 Workshop Report to each party in Docket No. R.04-04-003.

Executed on July 13, 2005, at Folsom, California.

C.N. Wilson

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