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

COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR ON WORKSHOP REPORT ON RESOURCE ADEQUACY ISSUES (Revised)

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Pursuant to the Assigned Commissioner's Ruling and Scoping Memo, issued on June 4, 2004, and the subsequent ruling of Administrative Law Judge ("ALJ") Wetzell extending the comment period, the California Independent System Operator ("CAISO") respectfully submits these comments on the Workshop Report on Resource Adequacy Issues prepared by ALJ Cooke in this proceeding ("Report"). As an initial matter, the CAISO strongly commends ALJ Cooke not only for her substantial and conscientious effort in preparing the Report, but also for her diligent leadership throughout the workshops. ALJ Cooke's contribution was invaluable to the success of the workshop process and the Commission's tangible progress toward implementation of a resource adequacy obligation.

I. Introduction

The Report states that its purpose "is to identify consensus agreements reached by the workshop participants, identify issues where agreement does not exist, and set forth options to resolve those issues whenever possible." (Report at 1.) Consistent with this stated purpose, the CAISO's comments focus on identifying where the Report may not accurately reflect the CAISO's understanding of the outcome of particular workshop discussions and offering further justification for the CAISO's preferred solution to unresolved issues. The CAISO's comments follow the structure set forth in the Report.

The CAISO further agrees with ALJ Cooke that proper resolution of certain issues not addressed in the workshops or Report remains fundamental to effective implementation of a resource adequacy obligation. The Report identifies penalties for noncompliance and rules for transitioning from year-ahead to real-time operations as examples of such important, yet deferred, issues. ALJ Wetzell, in his July 8, 2004, Ruling Requesting Additional Comments on Resource Adequacy ("July 8 Ruling"), seeks to reinforce the record on these topics by requesting, among other things, comments on rules to coordinate the Commission's resource adequacy obligation with CAISO's operational requirements. The CAISO appreciates the Commission's recognition that the CAISO's use of resources procured by utilities must be addressed to accomplish the basic objective of resource adequacy: to ensure reliable system operation. The CAISO further considers effective reporting, compliance, and enforcement mechanisms to constitute inextricable components of rules synchronizing the Commission's resource adequacy requirements and the CAISO's ongoing market redesign efforts and, therefore, encompassed by the July 8 Ruling. As such, the CAISO intends to address such issues in response to the July 8 Ruling and limits these comments to those topics addressed in the Report.

II. Report Section 2 – Timing and Reporting Issues

The Commission must decide whether the resource adequacy showing follows the procurement approval process or incorporates an assessment of the reasonableness of procurement decisions into the resource adequacy showing.

The CAISO concurs with the bulk of workshop participants that year-ahead forward commitment should not include an assessment of procurement reasonableness, but rather that the determination of reasonableness should be known in advance of making the year-ahead showing. In addition to the reasons set forth in the Report, this conclusion follows from two other considerations. First, if, as the CAISO strongly contends, an enforcement or penalty mechanism is necessary to enhance compliance with the year-ahead resource procurement requirement, then the reasonableness assessment cannot be contemporaneous with the compliance showing. Simply put, a load serving entity ("LSE") could not be reasonably penalized for failing to achieve the applicable resource adequacy threshold when presenting a resource for review that the utility believed in good faith to be reasonable and in compliance with its procurement plans. Second, depending on the timing of the showing, the more complicated reasonableness assessment could potentially affect the timing of the Commission's determination such that the IOUs procurement activities could be more vulnerable to the exercise of market power.

The Commission must decide when an LSE must demonstrate that it has met the 90% year-ahead resource adequacy requirement.

The Report identifies three options regarding the timing of the resource adequacy showing.

- 12 months prior to May for the full summer season (May – September), i.e., April 30, 2007 for May through September 2008
- 12 months before each month of the summer season, i.e., April 30, 2007 for May 2008, and May 31, 2007 for June 2008
- December 31 of the calendar year prior to the year of the resource adequacy showing

The CAISO prefers the first option for several reasons. First, as noted in the Report, the 12-month ahead options conform to Commission orders. In D.04-01-050, the Commission "establishe[d] a requirement that utilities forward contract 90% of their summer (May through

September) peaking needs (loads plus planning reserves) a year in advance." The use of the phrase "a year," rather than "the year" in advance, refutes Southern California Edison's ("SCE") assertion that the decision is susceptible to an interpretation that allows for a December 31 showing requirement. Moreover, SCE's reliance on Conclusion of Law #7 in D.04-01-050, which provides that "[t]he utilities shall meet this 15-17% requirement by no later than January 1, 2008," is misplaced. That statement merely acknowledges that the resource adequacy obligation is not restricted to the year-ahead showing, but imposes on utilities a requirement to actually be 100% resource adequate at the time of operational need throughout the calendar year.

Second, of the two 12-month options the single showing for the entire subsequent season is more administratively efficient than rolling monthly reports. This is especially true in light of the July 8 Ruling's request for comments on the proposal to require LSEs to meet 100% of their resource adequacy obligations a month in advance. As will be further addressed in the CAISO's response to the July 8 Ruling, the CAISO has vigorously and repeatedly endorsed the adoption by the Commission of a monthly reliability and reporting obligation. A monthly reporting obligation does not unduly limit the ability of LSEs to use short-term capacity purchases and maintains flexibility for LSEs to procure when market conditions are optimal. In contrast, such an approach precludes utilities from placing reliable cost-effective service to load at risk by over reliance on short-term capacity transactions. The Commission should ultimately adopt a monthly capacity-reporting obligation and, if so, any review procedures to determine compliance with this monthly obligation necessarily will be incremental to the prior yearly showing. Nevertheless, it makes sense to minimize the overlap of these review processes and the first option serves this objective.

Third, the CAISO harbors the concern referenced in the Report that the December 31 date may result in additional risk of LSE noncompliance and increases the risk of market power given the limited time period available to remedy any resulting deficiency. The Report notes that this concern is "minimized" to some extent if approval of procurement is separated from the resource adequacy showing. This is no doubt true if the reasonableness review entails granularity down to the evaluation of individual resources. If, in contrast, the approval involves acceptance of more generalized LSE strategies, the prior approval process is unlikely to fully mitigate or prevent risk of noncompliance.[1] Moreover, this risk may outweigh the benefits of greater information certainty cited by SCE. Again, there can be little dispute that a market participant will have greater confidence in market information as real-time operations draw near. This is equally true for buyers and sellers. As such, whether or not an LSE is able to minimize costs to ratepayers is likely to be more of an overall function of market conditions than the timing of the reporting requirement. In this regard, the CAISO believes an LSE is likely to have greater procurement flexibility in the 12-month ahead time frame than in the six-month or less time frame.[2]

III. Report Section 3 – Phase In

The Commission must decide what phase-in of the 15-17% planning reserve margin is appropriate and whether to modify the 2007 timing of implementation of the year-ahead 90% forward commitment showing.

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[1] The CAISO further notes that the character of any penalties imposed for noncompliance may also serve as a sufficient deterrent to LSE noncompliance. Thus, the CAISO recognizes that the timing of the reporting requirement is interdependent with the ultimate enforcement mechanisms adopted and, to the extent those mechanisms are effective, the timing of the reporting requirement may be relaxed to some degree.

[2] If the Commission adopts a December 31 reporting requirement, by the time the review process is completed to reveal an LSE procurement deficiency, there may be as little as two or three months available for the LSE to obtain replacement capacity.

In D.04-01-050, the Commission adopted a 15-17% planning reserve level to be phased in by no later than January 1, 2008. The July 8 Ruling references Governor Schwarzenegger's opinion that the phase-in date for resource adequacy of 2008 is "too slow" and President Peevey's concurrence that the phase-in "needs to be accelerated to ensure system reliability." Both the Governor and President Peevey are correct and the Commission should adopt the "fast phase-in" option. All LSEs should be required to acquire a reserve margin of no less than 10-12% in 2005 and fully satisfy the planning reserve margin by May 2006. However, as discussed below, it may not be feasible for LSEs to make their initial year-ahead showing by April 2005 for 2006 given the likely schedule for determining all threshold questions concerning resource counting and deliverability. Thus, the CAISO recommends that the first showing be scheduled for April 2006 for the 2007 summer season.

The CAISO has taken a very pragmatic stance on phase-in during this proceeding. Prior to issuance of D.04-01-050, the CAISO supported the Alternate Proposed Decision of President Peevey, which proposed to direct the utilities to meet the reserve requirement no later than the beginning of 2005.[3] In so doing, the CAISO acknowledged that a longer phase-in period rested on the concern that LSEs would be at a competitive disadvantage if required to ramp up too quickly from their current resource position to the full planning reserve margin. The CAISO argued at that time, however, that the threat of the exercise of market power by suppliers was mitigated by the current availability of excess resources. Moreover, the existence of the California Department of Water Resources ("DWR") contracts, which cover approximately 70% of the utilities' net short load requirement, further limits the utilities' exposure to potential market power given current resource conditions.

The CAISO also expressed its concern that by allowing an extended phase-in period, the current resource balance favorable to LSEs might degrade. Indeed, the CAISO has cited its Five Year Assessment (2004-2008) that shows a supply shortage could occur by 2008 under base case conditions.[4] The CAISO further believes that a slow phase-in of the resource adequacy obligation could, in fact, exacerbate any potential supply shortage. A planning reserve procurement requirement of only 8%, for instance, does not provide a strong incentive to preserve the availability of California's older generating plants. The uncertainty and brevity of the need for additional (short-term) reserve procurement could easily result in the retirement/mothball of these older generating plants, which could declare their unavailability with little-to-no notice. Similarly, a smaller, slower procurement phase-in of the planning reserve level does not properly encourage continued interest in new generation projects - already many such projects have been delayed or cancelled.

In general, older generating units operate less often and have higher variable costs. As a result, in the last two years, over 3,000 MW of generating capacity was retired or mothballed due to economic decisions by the generator owners. In addition, the CAISO has formally received notification of an additional 1,000 MW more capacity to be retired by the end of 2004 if these generating owners are not able to obtain a contract for next year. The California Energy Commission ("CEC") equally recognizes the potential for additional resource retirements. The CEC is analyzing the risk associated with potential future retirements through the Aging Power Plant study under Commissioners Geesman and Boyd.

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3 See, e.g., *Comments of the California Independent System Operator Corporation on the Proposed Decision of Judge Walwyn and the Alternate Proposed Decision of Commissioner Peevey Both Mailed on November 18, 2003,* R.01-10-024 (Dec. 8, 2003).

4 See, http://www.caiso.com/docs/09003a6080/28/5b/09003a6080285b79.pdf.

After publication of D.04-01-050, the CAISO reluctantly endorsed a linear phase-in to achieve the full planning reserve margin by 2008.[5] However, the CAISO again supports an accelerated phase-in given the willingness of the Governor and President Peevey to reconsider the phase-in schedule adopted in D.04-01-050. Supply conditions remain favorable to LSE purchasers. The threat of a bidding war resulting from a ramped up phase-in of the planning reserve margin is speculation. In any event, if there is evidence of supplier market power, LSEs should be allowed to request from the Commission a deferral of the phase-in schedule. The CAISO believes that any threat of market power is outweighed by the benefits of the fast phase-in option to promote the financing required to continue keeping the existing aging power plants in service (in-the short-term), and to entice continued and new generation construction. The fast phase-in creates a smoother bridge to replace older inefficient generation with newer less expensive generation, while buying time to implement other resource adequacy measures (such as targeted energy conservation programs).

That said, the CAISO recognizes that it may be overly ambitious to impose all reporting requirements simultaneously with the substantive procurement obligation. Threshold questions concerning counting resources and ascertaining the level at which the LSEs are currently resourced must first occur before any showing can be required at the Commission. Accordingly, given the anticipated schedule in this proceeding, the need for the CAISO to perform the necessary studies to engage in deliverability assessments, and the need for LSEs to procure and obtain a reasonableness review, the CAISO recommends that LSEs be required to demonstrate full compliance with the planning reserve margin beginning in April 2006 for the 2007 summer season.

IV. Report Section 4 - Load Forecasting Issues

The CAISO supports use of a coincident-peak based methodology because such a methodology is consistent with the historical approach to integrated planning and is the best means to assure that resources are procured most efficiently to satisfy system-wide resource requirements. In other words, a coincident-peak based approach is the methodology that establishes load-based resource requirements best able to reflect, and capture the benefits of, diversity on the system. However, the efficiency inherent in procuring resources based on a coincident-peak methodology requires an explicit recognition that resources procured by multiple LSEs will be pooled/shared to meet that system peak load.

In the past, utilities planned their systems in a manner that would ensure that sufficient capacity was available to serve their peak loads. In addition, the utilities allocated the embedded costs of such planning and procurement activities (*e.g.*, the cost of new power plants) to their customers based on each customer's relative contribution to the utility's peak load. The CAISO recommends that the Commission adopt a similar approach with respect to LSE procurement obligations. Under this approach, each LSE would be required to procure capacity in an amount necessary to serve its coincident peak-demand on the system, plus a planning reserve margin (established by the Commission at 15-17%). A coincident-peak based method would help to ensure that individual LSEs will not over-procure based on their respective non-coincident peak load. This approach results in less reserves being procured, yet provides reasonable assurance that adequate resources will be available to meet the system peak. Of course, this is predicated on the assumption that everyone is working together by pooling/sharing their respective resources to satisfy the system's peak load. This will not result, however, in the indiscriminate

[5] *Opening Comments of the California Independent System Operator Corporation on the Resource*

use of an LSE's resources by the CAISO to serve system needs. As previously stated by the CAISO, the CAISO's proposed market design – specifically, its proposed scheduling and unit commitment procedures – will enable LSEs to schedule and offer the use of their resources in a manner consistent with their preferred use (considering costs, environmental and other use restrictions).

The utilities must demonstrate that they have procured sufficient capacity for each hour of the five summer months. Significant diversity exists between the peaks during the months of May through September, so it is reasonable to require a demonstration that capacity is available a certain number of hours to cover the highest peak for each of the five individual summer months. Of course, application of a coincident peak based methodology requires the development of a system peak load forecast. The CAISO believes the CEC is an appropriate independent entity to develop a system peak load forecast that could be utilized to validate the LSE forecasts and to determine the coincidence factor for each LSE.

Finally, with respect to factoring in the impact of energy efficiency and demand-based programs, the CAISO recommends that the impact of energy efficiency investments be reflected in the peak-load forecasts for the system,[6] and interruptible as well as demand-response programs be included as "resources" that count towards satisfying the established procurement targets. CEC provided perspective to the issue of "how" to count these programs where the workshops focused principally on the "where" these programs should be counted, i.e. reduce the load obligation or be fully valued as resources. The CAISO has attached the background paper

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Adequacy Workshops, R.01-10-024 (March 4, 2004).

[6] This is appropriate because energy efficiency programs are intended to reduce the load obligation of the LSE. The CAISO also notes that simply assuming that energy efficiency programs will lead to load reductions in direct proportion to the total amount of expenditures is not realistic nor warranted. The CAISO recommends that energy efficiency programs be "counted" based on their historical effectiveness in actually reducing load and not be "counted" prospectively, based on the level of expenditures.

issued to the workshop participants on May 24th, 2004. This paper raises a number of critical issues with regard to the difficulty of determining the qualifying capacity of emergency and demand-based programs to reduce the load obligation. For example, Mr. Jaske notes "Some emergency programs are tied to end-uses, like air conditioning that have lower expected values in some months than other months, and thus the savings to be expected from the program in an expected value basis to similarly differ." Similarly, Mr. Jaske notes the problems of using interruptible programs not as emergency programs but rather as non-firm load that is not intended to be served during times that resources are unavailable[7]. This was the premise that a number of parties argued during this phase of the workshops. Lastly, the CEC, working in conjunction with the LSEs, should assess and validate the likely impact of energy efficiency programs based on historical experience and empirical data.

4.1 Load Information Each LSE Must Submit

The Commission needs to determine what level of confidentiality the forecast documentation will be afforded.

The CAISO frequently deals with commercially-sensitive information and appreciates the circumstances that require confidentiality. However, the CAISO will need to have unfettered access to data that is necessary to perform deliverability analysis and the determination of coincidence factors for each LSE. Should some level of confidentiality of the forecast documentation be necessary, the CAISO recommends that procedures be implemented to allow access to this documentation while preserving its confidentiality.

4.2.1 Coincidence Analysis

7 "[I]t appears that there is an inconsistency between the concept of 'firm and non-firm' loads embedded within the tariff construct of the interruptible tariffs,…." (*Background Paper: Treatment of Energy Efficiency and Demand Response Programs in Resource Adequacy Requirements,* Mike Jaske (CEC) (May 24, 2004), at p. 7.)

The Commission need not adopt the specific implementation method laid out in Appendix B, but must decide whether coincidence analysis should utilize LSE submitted forecasts or historical loads. In addition, the Commission must decide whether any supplemental analysis needs to be performed for purposes of identifying the forward obligation for resource adequacy purposes.

Application of a coincident peak based methodology requires the development of a system peak load forecast, and the quality of this system forecast is largely based upon the information from multiple LSEs. The CAISO believes the Commission should adopt the proposed approach where LSE resource adequacy obligations are based on the historical "share of the peak day."[8] This approach carries three valuable elements. First, determining obligations based on a historical basis provides greater certainty and avoids subjective judgments by the LSEs. Second, the annual resource adequacy process can be simplified by the CEC performing the coincidence analysis before the LSE load forecasts have been filed. Finally, this approach allows the CEC to make adjustments to the coincidence factor to account for situations where, for example, the LSE forecasts significantly differ from the historical data, or where the LSE forecasts have not been adjusted for transmission losses to generation.

Given the discussion and recommendations made in Appendix B, it is clear the Commission must determine that secondary analysis is necessary to reach an acceptable forward obligation for each LSE. This would simply entail identifying each LSE's contribution to the last year's system peak. Applying the same ratio to the coming year's forecast peak would identify that LSE's capacity obligation. This approach is currently in place in both the NY and PJM ISOs. This methodology will ensure all LSEs have clear responsibility to produce a load forecast for their respective load, and the CEC is tasked with determining the coincidence factor that must be used to calculate the LSEs resource adequacy obligation for the coming period. The

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[8] "Computing Coincidence Directly from Historical Adjusted Loads", pg. 13 Appendix B, Workshop Report

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CAISO further believes this approach will lead to coincidence factors that should be fairly stable over the long-run.

4.2.2 Should Forecasts (and Resource Adequacy Obligations) be Adjusted for Non-Coincidence?

The Commission must decide whether the load forecasts that set the resource adequacy 90% forward commitment obligation should be modified based on coincidence analysis. In addition, *it would be useful for the Commission to identify whether it is willing to have another entity, and if so, which one, perform the coincidence analysis and modification to load forecasts based on the coincidence analysis.*

While it appeared that most parties participating in the workshops recognized the value in meeting a coincident peak, the CAISO suggests there are additional complications by doing so. First, there must be an explicit policy decision that resources will be pooled when provided to the CAISO. Second, each LSE forecast must be adjusted for the coincidence factor that is developed by either the CEC or CAISO. Alternatively, the Commission may determine that a non-coincident requirement is appropriate. This approach would reduce the secondary process steps to get to an LSE specific requirement that is coincident with the CAISO's system-wide peak load. However, during the workshops, most parties argued against this approach because it would potentially result in an over procurement of capacity that was estimated between 1000 and 2000 MWs. Recognizing this consensus, the CAISO continues to support the use of a coincident-peak based methodology because it provides reasonable assurance that resources will be sufficient to meet load and because such a methodology is consistent with the historical approach to integrated planning.

4.3 Assignment of Load Responsibility to LSEs

The Commission must decide which approach to forecasting customer base and assignment of load to LSEs it prefers. In addition, it would be useful for the Commission *to identify whether it is willing to have another entity, and if so, which one, perform this assignment and reconciliation of load.*

The principle question being placed before the Commission is which base load should LSEs assume as they develop their respective load forecast. The CAISO believes the Commission has already indicated its preference for the use of existing load.[9] Further, it is likely to be more accurate and less opportunity to manipulate the results if the load responsibility is clearly based on current customer load vs. the LSE's best estimate of that load. In either case it is assumed the LSEs will increase their forecast for load growth.

It should be noted that either methodology may generate variations from the load forecast where a regime of core/non-core open access exists. This issue principally arises because load will be allowed to move from one LSE to another after the resource adequacy obligation has been established. As a result, the workshop report correctly identifies that some parties are concerned about overprocurement. Yet, it is equally possible that an LSE will under-procure for its needs.

The CAISO agrees that this issue bears on the determination of current customer base but equally affects the determination of load based on "best estimate." Therefore, the CAISO believes it is important for this Commission to consider whether customers of one LSE may take their capacity with them when they move to another LSE. Since there are many potential issues that must be resolved to implement such a policy, the CAISO recommends the Commission make the threshold decision that load forecasts will be based on the current customer load. The issue of whether capacity follows load from one LSE to another should be referred to the Commission's Core/Non-core proceeding.

4.4 <u>Inclusion of Losses in Load Forecasts</u>

The Commission needs to decide whether transmission losses should be reflected in the load forecast by defining an LSE's load at the generation busbar or whether transmission losses should be reflected in the generation counting protocols. If the Commission decides instead that load should be defined at the CAISO interface then it should direct LSEs to adjust their load forecast for UFE and reduce generation qualifying capacity to reflect transmission losses.

The Assigned Commissioner's June 6th Ruling and Scoping Memo required that utilities consider "the peak demand is defined to include all losses from end-user meter to generator busbar" in developing their load forecasts. The CAISO believes this guideline should be extended to all LSEs in their load forecasting methodologies.[10] The CAISO acknowledges that LSEs would have historical CAISO Settlement data at their disposal to develop their monthly forecast; however, Settlements data is based on telemetry from the Point Of Delivery (POD) and does not include transmission losses or UFE. Therefore, adjustment factors would have to be applied to LSEs forecast to convert their peak demand to the generator busbar. This issue was highlighted and addressed as part of the discussion in Appendix B and the CAISOs comments above (section 4.2.1).

Historically, and prior to deregulation, utilities calculated their real-time load based on telemetry of a generator "Unit Net MW" which is typically located on the low side of the generator step-up transformer bank – generator "busbar". The CAISO continued this trend and calculates the control area load based on telemetry from the low side of the generator step-up transformer bank (excluding auxiliary load). Future load forecasts for the five summer months

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9 *Assigned Commissioner's Ruling and Scoping Memo,* R.04-04-003 (June 4, 2004) at p. 5.

10 Alternatively, the Commission could adopt the requirement that LSE's forecast their load at the CAISO interface, or Point of Delivery (POD). Should the Commission elect this approach, there are associated decisions that must also be made to effectively implement the policy but which were not fully developed in the workshops. For example, the definition of qualifying capacity must require that a generator is derated to include the transmission loses it experiences from the busbar to the POD.

should be calculated in a similar manner to ensure consistency with the historical data and thus allow for effective use of the historical data.

The CAISO believes a correlation of actual CAISO historical load data and aggregated settlement data can be developed to correct LSE load forecasts for the expected transmission losses, UFE, and other necessary factors. This correlation factor between the POD and the generator busbar could then be weighted across all LSEs on a pro-rata basis as part of the CEC coincidence analysis.

V. Report Section 5 – Calculation of Quantifying Capacity

5.1 Incorporation of Forced Outage Factor into Qualifying Capacity LSE Owned/Controlled Resources

The Commission must decide whether to adopt the formulas set forth for LSE owned/controlled resources with or without including a forced outage factor.

Whether or not qualifying capacity for specific resources should be reduced to account for unit-specific forced outage rates ultimately may turn on administrative convenience despite the positive incentives created by including a forced outage factor. On the one hand, in order to achieve the primary objective of any resource adequacy requirement – reliably serving load – resources must be procured and measured on their ability to serve peak load. Ideally, each resource's historic performance would be assessed, including the unit's specific forced outage rates. In addition to increasing confidence that the reliability goals of resource adequacy would be realized, inclusion of a forced outage factor has the salutary effect of incenting generation owners to properly maintain their resources to maximize availability. Moreover, a concern exists, contested by the LSEs, that disregard of forced outage rates will encourage LSEs to maximize the capacity procured from older, less reliable, and therefore cheaper (capacity, but not energy) resources to satisfy their resource adequacy obligation. This procurement strategy would conflict with the reliability objectives underlying resource adequacy.

On the other hand, the positive economic and reliability impacts of including a forced outage factor are accompanied by administrative and other burdens. The CAISO has previously noted that assessing and evaluating each resource individually will be time-consuming and involve application of subjective judgments. Given that establishing clear accounting rules constitutes a prerequisite to implementation of the planning reserve margin, the complexity and high probability of disputes engendered by the forced outage factor could create the potential for delaying an accelerated phase-in schedule. (As noted above, the CAISO supports acceleration of the planning reserve margin.) Further, the reliance of the resource adequacy design on bilateral agreements, and the assumption that many of those agreements will be of substantial duration, cast further complexity on application of a forced outage factor, i.e., would the capacity of the secured resource vary over the contractual term?

At this stage in the development of the resource adequacy obligation, the CAISO recommends that the Commission require that LSEs negotiate availability or performance standards in contracts as a necessary element for that capacity to qualify. These types of provisions are common in the industry and may serve as an adequate incentive for the desired supplier conduct. Moreover, the Commission should evaluate unit performance on a periodic basis with a view toward determining the extent of that unit's continued eligibility to provide capacity for resource adequacy purposes.

5.2 Energy Limited Units

The Commission must decide whether this minimum hours requirement agreed upon by the parties for energy limited resources is acceptable.

As noted in the Report, the parties reached consensus on the treatment of energy limited resources. The parties agree that individual units must be available a minimum of 4 hours per day for 3 consecutive days. Further, the Report states that "the number of hours per month a unit must be available to be counted should be based on the 1998-2003 average monthly number of hours that system load exceeded 90% of the monthly system peak, rounded to the nearest ten." (Report at 24.) Consistent with the consensus position, the CAISO agrees with the Report. The reality is that during system peak conditions the marginal unit is likely to be energy-limited and therefore subject to the foregoing threshold requirements. However, the CAISO clarifies that the monthly hourly requirement applies to all resources and the LSEs' resource adequacy obligation more broadly.

In D.04-01-050, the Commission established that LSEs must procure resources to cover 90% of their "summer" peaking needs a year in advance. The Commission defined summer to encompass the entire months of May through September and peaking needs to include loads plus planning reserves. All LSE's must meet their respective resource adequacy duration obligations during this system peak. However, D.04-01-050 failed to establish whether LSEs must demonstrate compliance with the resource adequacy threshold for each hour of the five months, a certain number of hours to cover the highest peak for each month, or a certain number of hours to cover the highest peak for the entire summer period. Rather than require that the LSEs secure capacity for all hours during the summer period, the CAISO recommends that the Commission establish a separate requirement for each summer month's forecasted coincident system peak that covers a minimum quantity of hours based on an estimate of all the hours that peak could occur. It is also to serve this purpose that the CAISO calculated the average number of hours that load exceeded 90% of the monthly peak and as such should be part of an LSE's showing of resource adequacy.

5.3 Qualifying Capacity Formulas for Existing Qualifying Facility Contracts

The Commission must decide which of the options for solar (without gas backup) and wind resources to adopt, and whether to adopt formulas proposed for Existing Qualifying Facility Contracts in light of its decision on forced outages.

The CAISO has consistently emphasized that to achieve the goal of reliable system operation, resource adequacy counting conventions must generally reflect the resources' capability to serve peak load. In this regard, the CAISO stated in its Opening Comments on the Resource Adequacy Workshops, dated March 4, 2004, that "capacity levels from wind generation should not be considered when assessing the adequacy of utility plans to meet summer peak loads." This conclusion follows from the very low historic operating levels of wind generation during summer peak conditions. Accordingly, for both wind and solar without gas backup, the CAISO supports Option 1, which focuses on production during peak hours, but cannot support Option 2, which relies on application of Effective Load Carrying Capability.

The CAISO supports adoption of a formula for existing Qualifying Facility contracts that looks at historical performance. The ability of a Qualifying Facility to contribute to serving peak demand is not restricted to market conditions or equipment performance. Limitations, both physical and economic, may be imposed on the Qualifying Facility based on the interests or needs of its host. Consequently, historical performance provides the most rational basis to evaluate the likely output of Qualifying Facility Contracts.

5.4 DWR Contracts

The Commission must provide its definition of full credit and value of DWR contracts so that LSEs know how they can rely on the DWR contracts in the year-ahead showing.

The CAISO appreciates the need to define rules for counting the DWR contracts and the overall importance of this exercise to system reliability given the large quantity of energy embodied by the contracts. Nevertheless, the CAISO believes resolution of this issue is premature or, at a minimum, should be determined on an interim basis. On June 17, the Federal Energy Regulatory Commission ("FERC") "institute[d] a section 206 proceeding … for the purpose of investigating, in a structured fashion, the feasibility of both upholding these contracts without modification and implementing the CAISO's proposed redesign including the degree to which these types of contracts present market inefficiencies and are not operationally and economically compatible with the CAISO's proposed design; and the options for resolving the issues surrounding sellers' choice contracts." (*Order on Further Development of the California ISO's Market Design and Establishing Hearing Procedures,* 107 FERC ¶ 61,274 (2004).) The CAISO is hopeful that many of the issues related to the DWR contracts, including those that touch upon resource adequacy deliverability, will be resolved by the recent FERC proceeding.

5.5. <u>Contracts</u>

The Report notes that the debate over the qualifying capacity of contracts focused largely on system import contracts and intra-control area system sales. With respect to system imports contracts, substantial agreement was reached regarding the characteristics of an acceptable contract. At the workshops, the CAISO expressed concern that Service Schedule C of the Western Systems Power Pool Agreement ("WSPP Agreement") allows for interruption of a firm capacity/energy sale "where applicable to meet Seller's public utility or statutory obligations to its customers." (See Sec. 3.8 of Service Schedule C.) Upon further research and consideration, the CAISO believes that this provision represents an acceptable and appropriate risk and, therefore, concurs that the protocol table for system import contracts reflects agreed upon elements for qualifying capacity.

5.5.1 Intra-Control Area System Sales

The Commission must decide whether intra-control area system sales constitute qualifying capacity for purposes of the year-ahead resource adequacy showing.

The Report accurately captures the CAISO's concerns regarding acceptance of intra-control area system sales or "Firm LD" contracts as qualifying capacity. Firm LD contracts reflect system sales from unspecified resources that allow a seller to substitute payment of replacement costs for delivery of the purchased energy. Specifically, the CAISO has three concerns.

First, in the absence of any reference to a specific physical resource, performing a deliverability analysis becomes difficult, if not impossible. Deliverability is fundamental to reliably serving load. Deliverability also forms a secondary basis for discounting the capacity value of a resource. Thus, if Firm LD contracts are permitted without limitation, an incentive exists for sellers to sell all of their capacity through Firm LD contracts, defeating the ability to enforce deliverability requirements. Second, as noted in the Report, without the identification of the underlying physical resources, it is impossible to track whether a particular resource is being "oversold." Third, Firm LD contracts are structured to encourage sellers to chase the buyer offering the highest price, rather than physically deliver under the contract. This is especially problematic for California given the divergent market rules, i.e., price caps, between California and the rest of the west. Under conditions of system stress when physical delivery is most critical to meeting reliability needs, a seller may elect to sell power outside the State at uncapped prices and meet its contractual obligation through a financial transaction. Simply put, the fundamental problem identified by the CAISO is that the decision whether to deliver contractually under Firm LD contracts rests on financial considerations resulting from real-time conditions.

With respect to this third point, there was debate over whether the CAISO's contractual interpretation was accurate given that the definition of force majeur under both the WSPP Agreement and the Edison Electric Institute Agreement ("EEI Agreement") exclude economic reasons for failure to deliver. However, the issue is not with the definition of force majeur, but rather that the failure of delivery is not an event of default. Using the EEI Agreement as an example,[11] paragraph 4.2 states, "if Seller fails to schedule and/or deliver all or part of the Product pursuant to a Transaction, and such failure is not excused under the terms of the Product or by Buyer's failure to perform, then Seller shall pay Buyer ... an amount for such deficiency equal to the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price." Payment is the only remedy for failure to deliver. If the seller believes it can sell its power at a profit in excess of the expected difference between the replacement price and the contract price, it can do so without triggering other contractual penalties. A purpose of the uncontrollable force or force majeur definition is to clarify under what conditions of non-delivery payment is excused. The definition of uncontrollable force clearly states that its occurrence precludes suspension or any finding that the non-performing party is in default or liable for damages. Suspension and default are reserved for events of default. Paragraph 5.1(c) specifically exempts failure of delivery: "the failure to perform any material covenant or obligation set forth in this Agreement (except to the extent constituting a separate Event of Default, and except for such Party's obligations to deliver or receive the Product, the exclusive

[11] The WSPP Agreement is similarly structured. The EEI Agreement can be found at http://www.eei.org/industry_issues/legal_and_business_practices/master_contract/contract0004.pdf and the WSPP Agreement at http://www.wspp.org/Web%20Pages/WSPP%20Current%20Documents.htm.

remedy for which is provided in Article Four." As noted above, Article Four only calls for payment of the difference between contract price and replacement price. Thus, the EEI Agreement is largely a financial contract, and its obligation physical in appearance only. Simply put, the contractual obligation is physical only to the extent non-contractual business considerations and market conditions persuade the seller to perform. For the foregoing reasons, the CAISO contested characterizing Firm LD contracts as physical contracts and their unqualified acceptance as constituting qualifying capacity.

That being said, the CAISO recognizes the prevalence of Firm LD contracts as tools in the market and the potential hardship that would result from the blanket prohibition of such contracts from contributing to resource adequacy. The CAISO, therefore, supports the workshop suggestion that the Commission provide for a transition period to allow procurement of contracts that contain a unit specific requirement.

5.6 Estimating Load Reductions from Demand Response Programs

5.6.1 Must Demand Response Programs Meet a Minimum Hours Requirement to Have Value in the Resource Adequacy Showing?

Upon receipt of the CAISO data, the Commission must decide whether demand response resources may be relied upon in an LSE's year-ahead forward commitment showing without meeting the minimum hourly and monthly availability requirements recommended for energy limited generation resources. If the Commission decides that demand response resources must be available for more than two hours to be used in the year-ahead showing, the Commission must decide what minimum hourly and/or monthly availability requirements must be met.

The CAISO supports the proposal that demand response programs must meet the minimum requirement needed during the peak hours. The argument that the load duration curve is needle-like is misplaced.   As shown in Appendix G, a 2-hour product only supports less than 1% of the load, while a 6 hour product only meets 5.25% of the load. The CAISO supports an option that will allow a load serving entity to submit blocks of demand response that meets their peaking needs. This method supports the State's preference order for energy efficiency and demand response prior to new generation and does not put a cap on the total amount of demand response that consumers may be willing to provide. However, it should be noted that the LSEs must provide the CAISO with the dispatch order and the capability to dispatch the designated demand response programs in real time such that the real time dispatch capability supports the stacking order proposed in the procurement plan. In addition, the nature of the products should be considered in the qualification process. For example, a two-hour product that responds to price should only be considered for the top two hours and only if the price during those hours is above the threshold price trigger.

5.6.2 Should Demand Response Programs Be Treated as Demand Reduction or Supply for the Resource Adequacy Showing?

The Commission must decide whether demand response programs (interruptibles, direct load control, and price responsive demand) are treated as a demand reduction or supply resource for purposes of assessing resource adequacy.

The CAISO strongly asserts that demand response and interruptible loads should generally be counted as a resource. Demand response and interruptible loads operationally behave as a resource in that they can have "forced outages" because they may elect to respond and have a threshold price in which they are willing to respond. The CAISO has historically been required to carry operating reserves on the demand response programs per the WECC Minimum Operating Reserve Criteria (MORC).

A product that provides demand response or is designated as an interruptible load must be contributing load to the grid when called on. In many instances, the designated capacity for interruption is not contributing to the grid because the load at that particular instance is not operating. Historically, such products have not provided the designated interruptible capacity when called. In addition, price responsive load behaves as a generator with a threshold price at which it is willing to operate. For example, during Operating Reserve deficiencies the price may not be high enough for a particular demand response product to kick in and the load would remain on the system. In such circumstances, the CAISO would be required to serve that demand responsive load.

The Report notes that "the utilities argue that they do not now, and never have, carried reserves for the load signed up under interruptible programs, precisely because customers on these programs can be interrupted." (Report at 35.) This statement is incorrect. Today the utilities do not explicitly categorize a portion of their load forecast as interruptible. All loads in the control area are treated as firm and reserves are procured in compliance with the WECC MORC. The LSE's interruptible loads are assumed to be a responsibility to the CAISO and the CAISO takes appropriate steps to procure reserves in the market to cover the load. The CAISO would need special provisions to consider demand response as a non-firm load in which reserves would not be procured. Part of those provisions would require the load to meet CAISO EMS visibility requirements, submit hour-ahead schedules for interrupted load, install a settlement meter, submit to uninstructed deviation penalties, and provide the CAISO with direct dispatch capabilities.

5.7 Timing of When to Count Resources Under Construction

The Commission must decide when a project under construction is eligible to be counted for purposes of the year-ahead resource adequacy showing.

As noted in the Report, the issue of when you can count resources under construction is driven by the fact that the resource adequacy showing is made one year ahead and considerable uncertainty exists regarding whether the project will be online as anticipated. The CAISO supports a conservative answer to this issue and, therefore, supports Option 3. Option 3 provides that a resource can be counted only beginning 90-120 days after its scheduled commercial operation date as posted on the CEC's website. The outside range of 120 days should be adopted regardless of the imposition of penalties for an LSE that fails compliance with its resource adequacy obligation. The imposition of penalties is unlikely to provide financial incentives to fully overcome engineering and other construction obstacles and certainly cannot substitute for the reliability benefits of an online generating facility.

VI. Report Section 6 - Deliverability

Deliverability is an essential element of any resource adequacy requirement. Specifically, utilities 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. The Report properly clarifies, "[a]fter the qualifying capacity of a resource is determined, an analysis of whether the load can be delivered to 1) the aggregate of load and 2) the CAISO control area (for imports) must still be conducted. However, it should be noted that resource adequacy cannot be achieved without a clear obligation to procure resources for load pockets. Some parties argue this is not deliverability. The recent Reliability Order makes clear the Commission's thinking about this third issue, "it is also a utility responsibility to procure all the resources necessary to meet its load, not only service area wide but also locally."

Therefore, the CAISO remains committed to the premise that procurement for load pockets is an essential element of any effective resource adequacy requirement. Thus, the CAISO continues to discuss deliverability in three distinct ways. Ultimately, the Commission should require the utilities to demonstrate the "deliverability" of the resources they procure in both their annual resource plans and their long-term resource plans.

The "Straw-Person" Deliverability Proposal, included as Attachment D in the Report, was comprised of three essential deliverability tests.[12] Each of these tests would be required for the overall deliverability methodology to ensure that resources procured by LSEs would be deliverable to load. 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.

The generation and import deliverability tests focus on ensuring that generation and control area imports will not be constrained, during peak load conditions, due to transmission limitations associated with a localized generation pocket. At the same time, the tests ensure that any interactions between control area imports and generation pockets do not result in transmission constraints limiting the deliverability of the generation and imports. An assumption in this analysis is that there is sufficient generation located inside of all load pockets. This assumption is valid because the complete deliverability methodology includes a third test to ensure that there is sufficient generation located inside transmission constrained areas or load pockets that can be dispatched for resource adequacy deliverability purposes. If this third test was omitted, then one of the underlying assumptions in the generation and import deliverability tests would be invalid.

The Report raises the significant issue of "pooling".[13] The CAISO and the parties discussed the efficiency of each LSE procuring resources to serve the aggregate load on a system-wide coincident peak load. However, the underlying policy question remains whether

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[12] During the workshops, the CAISO delineated a tentative timeline for performing the deliverability assessments. The initial assessment is likely to take 6 months to collect data, conduct the studies, review with stakeholders, and issue the generator and intertie capacity values. After this baseline is established the CAISO believes it will be able to complete the annual updates in approximately two months.

the Commission intends that these resources will be utilized by the CAISO to serve the system needs. If this is the case, there may be times in which the resources of one LSE are actually being used to serve the load of another LSE. Of course the reverse may occur at other times during the year. Yet the underlying premise is that there are benefits that accrue to all LSEs by procuring to meet a coincident system peak load and sharing (pooling) these resources rather than procuring to their unique peak loads. This is the fundamental construct of the "power pools" that have historically operated in New York, New England and the Mid-Atlantic States and that was assumed by the presently functioning independent system operators in those regions. Thus, while the sharing may occur from time to time, it is important to recognize the over-arching benefits of reliable electric system operations and efficient procurement can be achieved.

6.1 Baseline Analysis of Deliverability of Resources to CAISO Control Area and Aggregate of Load

The Commission must decide whether the baseline deliverability analysis should contain a preference for existing internal generation and limit import capacity at the historical usage level, for purposes of the year-ahead 90% forward commitment requirements.

It should be noted that this analysis and the underlying assumptions are necessary to establish the deliverability of existing California generators. Thus, the proposed deliverability analysis contains a preference for internal generation because most parties saw that these resources are readily available to serve California load. The issue regarding limiting import capacity also had much discussion that resulted in the final proposal. As discussed during the workshops, the initial CAISO analysis indicates that most existing contracts will be accommodated and still allow a portion of intertie capacity for economy energy purchases. Yet it is clear the level of import capacity utilized for resource adequacy may need to change over

[13] The parties seek the Commission's confirmation that this assumption is accurate

time. Therefore, an enhancement to this methodology could be included when LSEs determine that additional import capacity is needed beyond historical usage. For example, if an LSE's long-term resource plan indicates a level of imports that exceeds historical import capacity, then the LSE could work with the CAISO, Commission, and CEC to investigate the availability of these additional imports. It should be noted that these limits are solely for the purpose of allocating import capacity for resource adequacy planning purposes and do not limit an LSE's ability to utilize the CAISO markets to bring energy into California for load service.

6.2 How Should "Deliverability" be Allocated to Existing Resources if Deliverability to Aggregate of Load is Constrained?

The Commission must decide how to allocate "deliverability" to existing resources if deliverability to the aggregate of load is constrained.

The CAISO believes that FERC has already determined the method to address this issue. In the FERC Interconnection Order 2003, that Commission outlines a policy where generators that wish to meet the Control Area capacity needs are studied differently than those that simply wish to provide energy.[14] Therefore, it follows that those generators that have paid to assure their deliverability or received available transmission, as part of their interconnection to the grid, should have priority in the baseline deliverability study to determine their resource adequacy deliverability.

Any guidance the Commission can provide as to whether, and if so, how, deliverability of resources should be derated due to general system conditions will help provide certainty and investment direction.

During the workshops a number of scenarios were discussed that might affect the initial value determined for deliverability of a resource, such as transmission reconfigurations and load

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[14] "In response to PG&E, the principal difference between the study requirements for Energy Resource Interconnection Service and Network Resource Interconnection Service is that the study for Network Resource Interconnection Service identifies the Network Upgrades that are needed to allow the Generating Facility to

growth/reduction. In any case, the concern raised about this issue could cause significant negative impact to the long-term investment in the California electric infrastructure. What some parties are arguing is a regime where investors would pay to interconnect new generation and achieve a desired level of deliverability. However, because the transmission system changes over time their deliverability might degrade. Yet, if this were the case, the transmission owner would not be obligated to make transmission upgrades or otherwise compensate the generator for the loss in capacity they are able to qualify towards a resource adequacy requirement. It should be noted this potential outcome is not solely a problem for the generator but for any party that has contracted with the affected unit. These parties would now have a contract with a unit that is no longer able to meet a deliverability test at its full capacity because the transmission network was allowed to infringe on its original contracted value. Clearly, there must be commitment in the Commission resource adequacy policy that works in concert with the aforementioned FERC policy to assure investors and LSEs that their investments will have stability.

6.3 Allocation of Total Import Capacity

The Commission must decide which approach to allocating intertie capacity to adopt.

The Commission must decide if intertie capacity allocated to a particular LSE can be traded to another LSE and be able to count for resource adequacy purposes for the second LSE.

The Commission must decide whether to adopt specific duration of the allocation of intertie capacity for resource adequacy purposes, and if so, for how long that duration should last.

The Commission must decide how to allocate import capacity to LSEs for purposes of the year-ahead resource adequacy showing.

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contribute to meeting the ***overall capacity needs of the Control Area*** or planning region whereas the study for Energy Resource Interconnection Service does not." [Commission Conclusion, FERC Order 2003, Section 784]

First, the CAISO believes the preferable methodology is based on a pro-rata allocation to LSEs for their historical usage. This will ensure LSEs that have made long-term commitments and/or are using the interties on a consistent basis will have the confidence that capacity will qualify for resource adequacy. This approach will further coordinate with the CAISO's proposed market redesign in which the CAISO intends to assign congestion revenue rights to LSEs based on their previous year's usage.

The objective for allocating intertie capacity to the respective LSEs is to provide upfront guidance as to how much they may rely on the interties to meet their load serving needs from outside resources prior to making procurement commitments. However, LSEs may be successful in negotiating for capacity that exceeds their initial allocation. Therefore, once the initial allocation is accomplished, it would be efficient to allow LSEs to trade their respective capacity to better align with their procurement activities.

Next, parties debated the duration of intertie allocations. The deliverability proposal contemplates an annual allocation, but remains flexible enough to allow for longer terms. It might be helpful to begin with an annual allocation and consider allowing longer terms at a future time after LSEs and the CAISO get familiar with the resulting initial allocations.

In sum, the allocation of intertie capacity to the various LSEs is a necessary and essential part to the resource adequacy framework. California is a net importer and will likely continue to be for the foreseeable future. The Commission, by providing an initial allocation based on a CAISO analysis, will give the LSEs sufficient guidance to procure outside resources knowing they will be counted in the resource adequacy showing. Further, whether these allocations are annual or for longer terms, the Commission can provide greater certainty by allowing the LSEs to trade their respective allocations in secondary markets

6.4 Is there a Resource Adequacy Requirement in Load Pockets?

The Commission must decide whether deliverability should be assessed on aggregate basis or load pocket basis.

During the workshops a significant amount of time was spent discussing an obligation to procure for load pockets. The Report defines "A load pocket is a particular area of load with insufficient transmission to cover its load requirements, for example, the San Francisco Peninsula." However, this definition does not include a reference to generation that may exist within the load pocket. The resource adequacy principle is that since the transmission is insufficient, the LSE must rely upon a portion of the local generation if it exists. Alternatively, the LSE has the same options available as in the case were there is no local generation. e.g. demand response or construction of transmission and/or generation.

As the Report states, "other parties vigorously oppose this being a requirement for a resource to be utilized in the year-ahead resource adequacy showing." In addition, parties argue that deliverability to load pockets would effectively impose a reserve requirement not only on the system but also on the load pockets. What the parties fail to acknowledge is how they intended to reliably serve their load without sufficient transmission or committed resources to serve their load within specified load pockets. The CAISO is confident that the additional deliverability test will meet the intended directives of the Commission and not increase the overall planning reserve margin beyond the 15-17% level already established.

Some parties argue the load pockets can be addressed as part of the CAISO's annual Grid Planning process. However, this deliverability screen is not currently addressed in the CAISO Grid Planning process, which can only look to transmission solutions to load pocket problems, whereas the resource adequacy process can look to generation and demand solutions as well, i.e., can examine and weigh all resource options – the essence of integrated utility planning. In addition, the CAISO Grid Planning Standards do not adequately address load pockets that depend on the operation of numerous local generators to ensure reliable service to load. For example, after experiencing a transmission and local resource deficiency that resulted in rolling blackouts on June 14, 2000 in the San Francisco Bay Area load pocket, a special San Francisco Greater Bay Area Generation Outage Standard was added to the CAISO Grid Planning Standards. The CAISO proposes that a maximum Loss of Load Probability criterion be established for all load pockets in the CAISO Controlled Grid to ensure that sufficient transmission and local generation is installed for local reliability. This approach is similar to those used by other ISOs and most of the North American Electric Reliability Council regions.[15]

Further the Report indicates a proposal based on import limits to a load pocket. Under this concept, it appears that "Local Procurement %" means the amount of local generation in MW that needs to be procured as a percentage of the "Peak Load MW". The CAISO believes that the formulation for the "Local Procurement %" in the Report is incomplete. As written, it would imply that the "Local Procurement %" would increase as the Import Limit increases. A more appropriate formula might be written as follows:

$$\text{Local Procurement \%} = \frac{\text{Peak Load MW} - \text{Import Limit MW}^{16}}{\text{Peak Load MW}}$$

However, the CAISO believes that even this formulation is insufficient. The simple formulation in the Report or the revised version above could result in load shedding every time a

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15 In the nine regions except the WECC, the NERC regions have adopted a metric or set of metrics that measure resource adequacy. The regions either use a LOLP directly or convert this to a capacity margin or reserve margin.

16 This could be defined as the Capacity Transfer Limit which is described in Attachment 3 to Appendix D.

generator in the local area is unavailable during peak load conditions. Alternatively, the New York ISO determines a Local Procurement % by setting the amount procured locally at a level that ensures the Loss of Load Expectation or Probability in the local area and across the rest of the system is less than one day in 10 years. The PJM methodology is similar. The CAISO believes that this type of formulation is more in line with ensuring that resources are adequately deliverable to load, and it ensures a more consistent level of reliability across the IOU service territories.

The CAISO noted the importance of deliverability to load pockets in its opening comments and repeats them here to emphasis the issue remains unresolved. "Load within transmission-constrained areas is highly dependent on the availability of generation within the constrained area and the transfer capability of the transmission system. Because transmission capability is limited and may be unable to transmit a sufficient amount of resources located outside of the constrained area to load, the reliability of service to this type of load is heavily dependent upon the availability of the local generation for meeting its resource adequacy needs. Local transmission constrained areas should have sufficient transmission so that an adequate amount of generation from resources located outside the local area can be delivered to serve the local load. The probability of load within the local area exceeding the available capacity resources located in the local area and imported into the local area should be equivalent to the probability of control area load exceeding the amount of capacity resources available to the overall control area. Therefore, the CAISO recommends that, as part of assessing the deliverability of an LSE's general portfolio of resources, particular focus be placed on assessing the deliverability of the procured resources to serve load in such locally constrained load pockets."

VII. Report Section 7 – Other Topics Discussed at Workshop

7.1 Multi-Year Forward Contracting Requirement

The Commission must decide whether it wished to entertain this requirement at this time.

The CAISO generally supports adoption of a requirement that LSEs demonstrate long-term procurement 1-3 years in advance. Under the current framework, the IOU's are not required to show forward commitments more than a year in advance. The long-term resource plans to be prepared by the three major IOUs this proceeding will generate 10 year conceptual resource plans. The projects included in those plans are not required to be firm projects. A transmission or generation project is not considered firm until it has received 100% financial commitment from a credit worthy project sponsor. Thus, in order for most types of new resources to be built by the time needed to meet system needs, the resources must obtain financial commitments more than a year in advance. A multi-year commitment approach, therefore, will support timely construction of new infrastructure.

Many new generation projects may require long-lead time (3-10 years) transmission projects to be in service to ensure deliverability under peak load conditions and to avoid uneconomic congestion costs. In the CAISO Grid Planning process, Participating Transmission Owners ("PTOs") are required to demonstrate that they have firm project plans in place so that the projects can be permitted and constructed prior to the date that needed for reliability. This means that the PTOs have a requirement to make firm commitments to transmission projects needed to meet 100% of their transmission needs, 3-10 years in advance.

Given the coordination required between the resource procurement process and the transmission planning process, a similar multi-year, firm commitment requirement should be included in the resource procurement process.

7.3 Capacity Tagging

The Commission must decide whether a resource that has received a capacity tag, as defined above, is acceptable for purposes of the 90% year-ahead forward commitment showing. The parties also believe that the Commission must decide in advance whether use of the resulting market is reasonable.[17]

The concept of capacity tagging is founded in the principle that a standard homogeneous product can be defined for identifying resources that are capable of meeting resource adequacy obligations. The CAISO supports this notion because such a product can be very helpful in many respects. At its most basis level it creates a consistent counting mechanism by which all parties can quantify resources that meet the resource adequacy criteria. This feature necessarily positions capacity tagging as a complementary feature to any resource adequacy framework and supports the notion of a core/non-core open access environment.

Finally, the CAISO believes that capacity tagging provides an efficient manner in which LSE can trade capacity and avoid stranding resources as long as the product incorporates allowances for local capacity that is fairly priced. As the workshop report indicates, "By creating a standardized tradable capacity product and market, resources can be shared more effectively between LSEs because they know that the product will meet the Commission's resource adequacy requirements."

[17] The workshop moderator is not clear whether this recommendation addresses reasonableness in the context of the price that results from the capacity tag market or whether it is reasonable to utilize a capacity tag to meet resource adequacy requirements.

Thus, the Commission should support the development of capacity tags. The threshold issue that requires immediate action is the definition of a capacity tag.[18] Once the product is defined, the CAISO believes these "tags" can immediately begin trading as part of the bilateral contracting process. Over time and with sufficient transaction volume a formal secondary market may develop for auctioning capacity tags.

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[18] The workshop report provides an acceptable definition. "A capacity tag would be for a specified amount of capacity (i.e., 1 MW) from a resource, based upon the definition of qualifying capacity for that type of resource, that also passes the deliverability screen. The parties refer to this part of the minimum requirements as being "certified".

BACKGROUND PAPER: TREATMENT OF ENERGY EFFICIENCY AND DEMAND RESPONSE PROGRAMS IN RESOURCE ADEQUACY REQUIREMENTS

Mike Jaske, CEC
5/24/2004

1. Summary of EE and DR Treatment in Load Forecasting Protocols

As a result of several rounds of discussion, participants in a load forecasting team developed a Load Forecasting Strawperson. This document was issued April 9, 2004, and was discussed in a public workshop on April 14. While the differences noted in the document were discussed at the workshop, only limited resolution of them was reached at the workshop. Treatment of energy efficiency and demand response program impacts was not fully resolved.

a. Previous Agreements and Disagreements

Agreement: Energy efficiency program hourly impacts are to be subtracted from "base" load forecasting if programs are committed.[1]

Disagreement: Demand response program impacts resulting from committed programs and tariffs are to be:

(1) subtracted from load,
OR
(2) included as resources,
OR
(3) subtracted from load if the program or tariff is non-dispatchable and carried as a resource if the program or tariff is dispatchable..

The load forecasting working team's previous discussions have failed to resolve how to count demand response tariff and program impacts.

b. Suggested Resolution of Disagreement on Treatment of Demand Response

At the April 14, 2003 load forecasting protocol workshop, a suggestion was made that demand response programs carried as resources shall receive a credit toward satisfying the forward commitment obligation of equal to their impact times the planning reserve margin value appropriate to that year/month/hour. This would remove the apparent "penalty" LSEs perceived that would result if demand response was carried as a resource. The suggested "credit" did not resolve the issue, of "where to count" demand response programs and tariffs.

[1] Load Forecasting Strawperson, April 9, 2004, p. 7.

2. Proposed Definition of Terms

Implementation of the agreements documented in the Load Forecasting Strawperson would be inhibited unless a variety of terms not fully defined therein were clear and unambiguous. To reduce the chances of future disagreement, the following suggested definitions are proposed.

"*Committed*" means the regulatory authority has authorized funding and at least a preliminary design of programs or programs from which initial set of hourly load impacts can be quantified.

"*Hourly impacts*" means that a methodology exists to translate funding through the following steps: participation rate of customers, nature of end-uses affected by program, influences of program measures on end-uses, either engineering or econometric procedure to estimate hourly load impacts from measure influences on end-uses.

"*Authorized funding*" means the CPUC for an IOU or the governing board for a municipal utility has authorized expenditures of funds for a program or programs intended to create a general level of impact on load through the creation, modification or expansion of energy efficiency and/or demand response capability development programs.

"*Preliminary design*" means that the general idea of how a program or programs has been specified, including the type of customers to be targeted, the measures or end-uses for which behavioral change or structural modifications are intended have been identified, and the mechanisms (subsidies, rate reductions, bill credits, purchase buy downs, special financing, special credit arrangements, etc.) to induce customers to participate and take action have been specified at a level that would allow some prediction of participation levels.

3. Proposed Determination of Hourly Impacts of Programs and Tariffs

Because of the unresolved discussions about "where to count" only very limited discussions have yet taken place on "how to count" the impacts of energy efficiency or demand response programs.

<u>a. Energy Efficiency Program Impacts</u>

Energy efficiency impacts should be quantified using what ever methodology the LSE believes appropriate to determine hourly impacts that are designed to be unbiased, e.g. produces neither high nor low impacts and generally consistent with adopted measurement and evaluation studies and protocols.[2] Since these impacts will not be not directly revealed unless load forecasting reporting requirements at some point require them to be identified, they need not be addressed in any detail now.

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[2] Ibid., p. 7.

Some LSE customers may be affected by energy efficiency programs that are sponsored by an IOU or other third-party entity. For example ESP DA customers could be affected by IOU energy efficiency programs, or future community choice aggregators (CCA) may be affected by IOUs running energy efficiency programs in portions of service areas where generation services for loads are the responsibility of a CCA. In such instances, some LSE preliminary load forecasts may need to be adjusted before final load forecasts are determined.[3]

b. Interruptible/Curtailable Program Impacts

While the workshops have discussed three options for "where to count" demand response programs,[4] the workshops have not addressed "how to count" the impacts of these programs.

Several quantification issues are described below.

1. *Emergency Program Operating Constraints*

D.02-04-060 authorized funding for various IOU-administered emergency curtailment programs for aggregate impacts not to exceed 2500 MW across all three IOUs. The IOU monthly reports required by D.02-04-060 dated April 21, 2004 suggest that approximately 1,500 MW of emergency capability, in total for all three IOUs, are available across the various programs.

The various programs have individual triggering conditions, limitations on monthly and annual hours of curtailment, and in some instances penalties for non-compliance that would be important to gauging the amount of load curtailment subscribed to the programs that might actually take place during real emergency events. Table 1 summarizes key provisions for each of the three major programs encompassing the great majority of interruptible program capability.

There is no discussion in the Load Forecasting Strawperson of the methodology for tying quantification of emergency program operations to resource capability for each of the five summer months May – September. There was limited discussion in the RA Workshop of April 14, 2005 of the issue of subtraction of some emergency program load reductions in load forecasts given the characterization of interruptible tariff loads as distinguishing between "firm" and "non-firm" loads. In contrast, some participants observed that the triggering condition language for the interruptible tariffs, in conjunction with a higher level of resources achieved through a resource adequacy requirement, made the probability of actually using emergency programs much smaller than in the past. Thus, not only was the "where to count" issue not resolved, but there was no discussion of the "how to count" issue let along how this might be quantitatively resolved for the load forecasts for each of the specific months May - September.

[3] Ibid., p. 20.
[4] Ibid., p. 8.

Table 1
Overview of Key Provisions for Major Interruptible Programs

Interruptible Program	Operating Limitations	Triggering Conditions
Interruptible Tariff	A customer will be requested to curtail demand, under the emergency curtailment program, no more than one time per day, 40 hours per month, four times per week, and 30 times per year. The customer will be given at least 30 minutes notice before each curtailment. Curtailments will not exceed six hours for any individual interruption or 100 hours for the entire year. [E20, ¶11.f]	PG&E will make requests for such curtailments from its non-firm service customers upon notification from the California Independent System Operator (ISO) that a system-wide or local operating condition exists which will impair the ability of the ISO to meet the demands of PG&E's other customers. The ISO is expected to issue load curtailment directives to PG&E in those instances where load reductions are necessary in order to maintain system-wide operating reserves above the 5 percent level throughout the next operating hour, or if such load reductions are the sole remaining measure available in order to mitigate transmission overloads in the PG&E area. [E20, ¶11]
BIP	Limit to one four-hour event per day, and no more than three consecutive days; limit to 10 events per month, and 120 hours per calendar year. [D.02-04-060]	A load curtailment event may be triggered when a Stage 2 emergency is called or when transmission system contingencies justify calling a localized block of participants. [D.02-04-060]
D-APS (SCE only)	The number of cycling periods under Subsection a. and b. is limited to 15 occurrences per year during the period from the first Sunday in June to the first Sunday in October, inclusive, of each year, and a cycling period is limited to no more than 6 hours duration per day. Cycling under Subsection b. is limited to situations when SCE declares a Category One, Two, or Three Storm Alert and a condition exists that creates disruptions on SCE's electrical distribution system which, if left unresolved, could damage the electrical system or cause a more widespread interruption in the supply of power. [D-APS, ¶SC5]	A cycling period is one in which the service may be interrupted: a. When the Independent System Operator (ISO) directs SCE to curtail specific amounts of load (up to the full capability of load curtailment programs) sufficient to maintain operating reserves above the five percent level through the next forecast hour; b. When a declaration by SCE of a Category One, Two, or Three Storm Alert exists which may jeopardize the integrity of SCE's distribution facilities; [D-APS, ¶SC 5]

2. *Linkage of Monthly Impacts to Within Season Trends*

On an expected value basis, a June load forecast is lower than an August load forecast. In part this is because the weather is cooler, and in part there are other agricultural and industrial factors that differ across months of the summer season in a systematic way. One is on-farm pumping loads, which can generally be expected to be lower in May than August or September. Some emergency programs are tied to end-uses, like air conditioning that have lower expected values in some months than other months, and thus the savings to be expected from the program in an expected value basis to similarly differ.

There is relatively little public data available to quantify the expected monthly capabilities of these weather sensitive and seasonal variations, because historically the evaluations have been conducted for events when the programs have been operated. Unfortunately, such events are tied to situations where there are emergencies, which are events that are stressing supply-demand balances, which are of two types in these May-June off-season months: (1) transmission contingency emergencies unrelated to system adequacy conditions, or (2) extreme weather conditions that are far outside of the 1:2 weather likely for the month. Neither of these types of events are representative of events that represent average peak weather conditions. For example, if is conceivable that SCE's residential air conditioner cycling program, rated at 300 MW under typical annual system peak emergencies, might only produce 50 or 100 MW of load reduction in June average peak conditions.

<u>c. Price Responsive Demand Program/Tariff Impacts</u>

In addition to the issues noted above for emergency programs, the newly emergent price responsive demand programs have a wide range of operational limitations and qualifications that would affect how to estimate realistic estimates of load capability (whether subtracted from demand or carried as a resource) that have not yet been addressed in workshops.

Direct customer responsive to price signals (such as an RTP tariff now in development, but not yet authorized) would have impacts that were directionally the same as tighter supply-demand balances, e.g. the lower the margin or resources over loads, the greater one might expect market process, and the greater one might expect RTP tariff participant response to these prices.

Table 2 identifies some of the basic characteristics of the major PRD programs and tariffs launched by D.03-06-032 as active programs to ones to be developed.

Table 2
Overview of Key Provisions of Price Responsive Demand Programs

Program/Tariff	Operating Limitations	Triggering Conditions	Status
Critical Peak Pricing Tariff	6 hours per event, and 12 events per TOU season[5]		Authorized, recruiting participants, ready to operate
Demand Bidding Program (Day Ahead Version)	None	IOU forecast of avoided costs exceed \$150/mWh for four consecutive hours between Noon and 8PM on the subsequent day	Authorized, recruiting participants, ready to operate
Demand Bidding Program (Day Of Version)	None	IOU believes an outstanding system issue may affect system reliability	Authorized, recruiting participants, ready to operate
CPA Demand Reserves Partnership	Limited to 24 hours per month and 150 hours per year	DWR discretion to determine when system reliability requires load curtailments	Authorized, recruiting participants, ready to operate; final negotiations underway to shift triggering responsibility from DWR to IOUs and to link this to economic criteria
Real Time Pricing Tariff (Day Ahead Version)	None	None. IOU flows forecasted hourly market prices for the subsequent day to participants by 5PM	In development for 2005 operation; comments on disputed design issues filed with CPUC on April 1, 2004

4. Use of Dispatchible DR Programs as a Resource

<u>a. Illustrative Use of Dispatchible DR programs as Qualifying Reseource</u>

Section 2 of this paper identifies that some participants propose that dispatchible DR programs count as resources to be used to satisfy the forward commitment obligations created by D.04-01-050. Subsequent to the April 14 load forecasting workshop, additional resource adequacy workshops have elicited some agreement about the number of high load hours a resource must be capable of operating for each of the five summer

[5] Each IOU has a unique set of months defining its TOU summer season.

months May - September.[6] In light of the minimum hours per month proposed by the CAISO, how might a dispatchible demand response program be counted?

Table 3 illustrates how a combination of DR programs might be used to satisfy the minimum performance requirements of qualifying capacity to meet the hourly operating requirements proposed by the CAISO.

Table 3
Illlustration of SCE Satisfying Commitment Obligations Using DR

RA Obligation	May	June	July	August	Sept	Total
Aggregate Hours by Month	30	40	40	60	40	210
I6, Non-Firm	30	30	20	10	10	100
BIP	0	10	10	30	20	70
D-APS	NA	0	10	20	10	40
Sum over DR Prog.	30	40	40	60	40	210

Thus, in this illustration, three MW of dispatchible DR capability (one each from I6, BIP, and D-APS) are used to satisfy the minimum obligations for one MW of qualifying capacity. Note that none of the three DR programs is operated in a manner that exceeds its aggregate annual or monthly limits, and some capability is preserved for actual emergencies. There are other combinations of operating patterns that would also satisfy the 210 hour minimum obligation.

b. Regular Use of Emergency Program Capability

It is not clear whether participants in emergency programs might be willing to be curtailed to this high level, even though the individual programs permit this amount. Many customers participate on the expectation that they will not be called upon to the maximum permitted. To the extent they actually are called at this level, then some drop out from programs might be expected when customers are permitted to do so. It might be more realistic to use price responsive demand programs for this purpose, since there is less ambiguity about where such "resources" fall in the continuum between planning reserves and "last resort" emergency load curtailment capability.

Finally, it appears that there is an inconsistency between the concept of "firm and non-firm" loads embedded within the tariff construct of the interruptible tariffs, such as SCE's I6, and their use in just emergency conditions. The IOU notion that non-firm loads should not be planned for, is consistent with either subtracting these loads from load forecasts or carrying them as reserves that would be operated frequently. This notion is not consistent with conventional discussion of these programs and tariffs as providing emergency load curtailments that are only triggered under circumstances where the CAISO control area is violating WECC operating reserves and the system's expected

[6] CAISO, *CAISO Straw Proposal for Determining the Number of Hours During the Summer Months the Resource Adequacy Requirements Apply*, May 13, 2004.

operating reserve margin is declining. If interruptible program participants are shifted to a functional “non-firm” status, then does the CAISO need additional emergency load curtailment capability from some other category of customers that would actually be reserved for use in emergencies? If so, how much capability should this be?

5. Additional Challenges Presented by Commission Decisions

In addition to the complications of deciding where to count, and what to count, there are several issues that the CPUC itself has raised that must be addressed for the energy efficiency and load forecasting decisions made in D.04-01-050, and other related CPUC proceedings. These challenges collectively represent somewhat mixed messages about the importance of obtaining full “credit” for these programs in a resource adequacy context, and then making accurate estimates.

a. Energy Efficiency

D.03-12-062 authorized additional ratepayer funding for energy efficiency programs above and beyond that available through energy efficiency public goods charge (EEPGC) programs, and directed that the details of the programs be addressed in R.01-08-028. D0.4-01-050 is concerned that IOUs submit energy efficiency program designs into R.01-08-028 that produce at least as much impact as those included in the long run plans evaluated in R.01-10-024.

> “We therefore establish the requirement here that utility procurement related energy efficiency program submissions be equal to or greater than those forecasted in their long-term plans for the forecast/program period in question.” [p. 106]

This could be interpreted to mean that these “submissions” means the impacts proposed for the programs in various filings of R.01-10-024 during spring-summer 2003.

Given this, can one also speculate that the amounts of impacts that are to be included within load forecasts prepared for resource adequacy compliance purposes also include these same level of impacts?

b. Demand Response

The CPUC is actively pursuing price responsive demand in R.02-06-001 in cooperation with the CEC and CPA. D.03-06-032 establishes numeric targets for annual PRD aggregate impacts which IOUs are directed to achieve for years 2003 through 2007. Table 4 reproduces the annual targets established for each IOU from this decision. D.03-06-032 requires IOUs to include these impacts in their procurement plans.[7] D.04-01-050 itself explicitly says:

[7] D.03-06-032, OP#1.

> "In conducting the workshops and developing a resource adequacy framework, the Commission reiterates its commitment that full value be given to the preferred resources identified in the Energy Action Plan and to the long run DWR contracts." [p. 47]
>
> "In guiding the workshops, we reiterate our concern that these non-traditional resources be fully and fairly evaluated, …' [p. 48]
>
> "The ability to count these resources, under reasonable and realistic parameters, should therefore be addressed in the workshop." [p. 48]

Unfortunately, reasonable reading of these three passages might detect an inconsistency. Are the PRD goals to be given the value identified in D.03-06-032, or should the programs identified by D.03-06-032 and subsequently authorizing decisions be fairly and realistically evaluated to identify and include their likely impacts? How much differences might exist between these two interpretations?

Table 4.
Demand Response Goals

Year	PG&E	Edison	SDG&E
2003	150 MW	150 MW	30 MW
2004	400 MW	400 MW	80 MW
2005	3% of the annual system peak demand		
2006	4% of the annual system peak demand		
2007	5% of the annual system peak demand		

Source: D.03-06-032, p. 9.

CERTIFICATE OF SERVICE

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

Executed on July 14, 2004, at Folsom, California.

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