RESOURCE ADEQUACY

PHASE 2

WORKSHOP REPORT

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the California Public Utilities Commission

and the California Energy Commission

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Executive Summary

Phase 2 Workshop Report Does Not Provide Policy Preference

This report is not intended to define the policy preferences for either the California Public Utilities Commission ("CPUC" or "Commission") or the California Energy Commission ("CEC"). Staff from each agency worked collaboratively in drafting this report, and worked together in the facilitation of the 19 full-day Phase 2 Workshops that took place between November 2004 and April 2005. This report summarizes the discussions of the various parties on the various policy options for how to establish Resource Adequacy Requirements ("RAR") upon all load-serving entities ("LSEs") within the service territories of California's Investor Owned Utilities ("IOUs"). This report further identifies both areas of consensus and positions to issues for which the Commission must make a policy determination.

Resource Adequacy Requirement Intention for Stability

In D.04-01-050, the CPUC outlined a new policy objective intended to insure reliability and a platform for investment in new infrastructure. This policy would give the California Independent System Operator (CAISO) assurance of adequate generation to meet peak demand and investors assurance of market stability by requiring the three major investor-owned utilities, energy service providers (ESPs), and community choice aggregators (collectively, LSEs) to procure generation resources 15% to 17% above peak demand. Reliability comprises two components, adequacy and security. The purpose of a resource-adequacy requirement is to ensure the system meets its reliability needs for adequacy by providing an avenue for the carrying costs of physical generations to be recovered

The Commission has previously adopted a capacity-based resource adequacy requirement, the primary purpose of which is to provide for a sustainable revenue stream over time that is missing from the capped energy markets so that physical generation remains economically viable to be available when and where required and that new resources come online in a timely fashion. Providing for market stability is critical for promoting infrastructure investment and for assuring that resources required to serve California are available in both the short and long term. A stable market also reduces investment risk and consequently the risk premiums passed through to California's ratepayers under any market design. In addition, the CPUC must assure that long-term planning for resource adequacy supports the CAISO shorter-term operational requirements by assuring, among other things, that resources are deliverable and in the correct local areas.[1]

In April 2005, the CPUC issued a proposed decision intended to clarify the obligation of LSEs. This proposed decision outlined a policy wherein each LSE would be required to purchase sufficient capacity to meet the peak demand for each month, for all hours of that month (this came to be known as the "all hours" approach). Many parties, particularly the LSEs, were concerned with how the "all hours" approach would be implemented, and what implications this approach would have on their operating costs.

The CPUC staff conducted workshops in April 2005 to flesh out the policy options for establishing the level of capacity each LSE would be required to procure. Through these workshops, two basic proposals emerged: a "top-down" approach, based on the methodology of the April "all hours" proposed decision (generally supported by the generators), and a "bottom-up" approach (favored by the LSEs).

California's Energy Agencies Moving Forward Together

The CPUC's development of Resource Adequacy Requirements is moving forward in parallel with proceedings at the FERC and CEC. The CPUC's RAR policy is intended to provide "a framework to ensure resource adequacy by laying a foundation for required infrastructure development and assuring that capacity is available when and where it is needed." (D.04-01-050, p11). At the same time, the CAISO is developing new market rules intended to remedy many of the existing problems associated with lack of adequate forward congestion management tools and infeasible scheduling. A resource adequacy requirement is a fundamental foundational component for the CAISO's forthcoming market design and means to assure

[1] We should be clear at the outset that the Commission has previously articulated, and continues to do so, its policy position that California's reserve requirements will be met through capacity-based RAR imposed on all load serving entities.

resource stability in the transition to the new market. The new CAISO market design is anticipated to be in place in 2007. In support of these efforts, the CEC will leverage its expertise by developing load forecasts.

As California implements these new resource adequacy rules and the CAISO remains in transition to its new market design, there will be adjustment to both elements that will have to be made as practical experience will highlight areas that may require revision. Coordination and collaboration are a fundamental element of assuring that any deficiencies in the RA rules get remedied quickly and effectively to support reliable grid operations and establish the intended market stability.

Coordination and collaboration between the CPUC and CAISO are necessary to assure that deficiencies in the Resource Adequacy rules get remedied quickly and effectively to support reliable grid operations.

Phase 2 Workshop Policy Issues For CPUC Consideration

The report follows the framework established in the Phase 1 workshops. The report is divided into five main chapters:

Chapter 2: Nature of Obligation –This section identifies who has the RAR obligation and what those obligations are.

Chapter 3: Interagency Coordination – the CPUC, CAISO, and CEC will need to work in concert to ensure that forecasted system and locational peaks will be met with reliable generation. How these energy agencies set and enforce RAR is critical to a successful roll-out of RAR and the CAISO's 2007 market re-design.

Chapter 4: Load Forecasting – the CPUC must establish how the LSEs will be measured against forecast peak **demand**. The CAISO and CPUC will rely on the CEC to evaluate forecasts of when and where peak demands will occur.

Chapter 5: Resource Counting – how generation products should qualify under RAR. Policy must establish how to evaluate the relative reliability benefits of various types of resources, including the **ability** of a resource to meet load demands in areas facing constrained transmission ("deliverability").

Chatper 6: Reporting/Review/Sanctions – the policy objectives of RAR must be backed by credible and appropriate means for reporting compliance, review of each LSE's RAR portfolio, and consequences for non-compliance.

Format of the workshop report

Within the five main chapters of the report listed above, this report seeks to address each of the 21 topic areas drawn from D.04-10-035 in ALJ Wetzell's November 19th, 2004 ruling. Table 2 below maps each topic area to the section of the report where that topic number is addressed. At the conclusion of each topic area, the report will highlight whether there was general consensus on the participant's preferred policy solution. *Where staff has determined that the CPUC must act (make a policy call, establish new interagency protocols, or tighten definitions), the report summarizes the issue in italics. Parties may wish to focus on these highlighted topics when preparing written comments.*

Inclusion and Consideration of Participants' "Working Proposals"

In numerous instances throughout the workshop process, parties submitted "Working Proposals" that outlined policy frameworks to address particular topic areas. These Working Proposals are distinct from the initial straw proposals brought to the workshops by any individual party in that the Working Proposals were developed in response to direction from the body of workshop participants. The collaborative nature of these Working Proposals provided an opportunity for some policy suggestions that had general consensus to get fleshed out, and were viewed by staff as particularly productive. For these reasons, Working Proposals apropos to a specific topic section are outlined in the body of the report; the text of the original Working Proposals are included in the Appendices.

Critical Path to Resource Adequacy: A Conceptual Timeline

The timeline for developing forecasts, acquiring resources and developing compliance filings for the CPUC, CEC and CAISO to review presents a critical path to Resource Adequacy. Staff has outlined below the necessary annual framework for resources adequacy implementation. The chart below shows a conceptual timeline of the actions that must be taken by market participants, CPUC, CEC, and CAISO. *In comments to this workshop report, parties are encouraged to comment on the components and timing of the annual framework and provide suggestions for streamlining and creating the maximum level of efficiency*.

Table 1
Draft Timeline - Critical Path to Annual Resource Adequacy

End of January (Year X)	CAISO requests base cases and load forecast for the following year from the Participating Transmission Owners ("PTOs").
February-March	PTOs develop base cases and load forecasts for the following year.
March	PTOs provide complete local area and system base cases and load forecasts for the following year to the CAISO.
April	
May	LSEs submit hourly load forecasts to CEC for review.
	IOUs submit Energy Efficiency ("EE"), Demand Response ("DR") and Distributed Generation ("DG") hourly impacts to the CEC for use in load forecast adjustments.
	CAISO establishes RAR capacity requirements in each local area.
	LSEs begin to procure energy and capacity to meet their RAR.
June	
July	CEC makes adjustments to LSE load forecasts and reports "out-of-scope" problems to CPUC.
August	LSEs submit plans for meeting local capacity portions of RAR to CAISO.
September	LSE submit compliance packages to CPUC, CAISO, and CEC.
October	CAISO determines adequacy of LSE procurement and examines what capacity (if any) the CAISO should purchase as "back stop".
	LSEs submit year-ahead compliance filing for locational RAR and 90% summer month requirement.
November	CAISO submits final "back-stop" contracts to FERC for approval.
December	
January 1 (Year X+1)	CAISO's "back stop" reliability contracts take effect.
	After-the-fact review takes place if adopted

Staff anticipates that the CAISO, CEC, and CPUC will have to make adjustments to the schedule for the first year. Prior to summer 2006, the LSEs and state agencies will be going through the RAR process for the first time, and despite the best efforts of all concerned, it is likely that some unforeseen problems may arise. Some critical steps may take longer than anticipated to accomplish, and other important tasks may not yet be adequately prescribed.

Procedural Background

Introduction of Resource Adequacy Framework – Phase 1

In January 2004, the CPUC established a long-term Resource Adequacy framework (D.04-01-050). This decision adopted a 15% to 17% planning reserve margin ("PRM") and directed that each LSE is responsible for acquiring sufficient reserves to meet its own customer load. To ensure reliability, the CPUC found in D.04-01-050 that 90% of each LSE's requirement (peak load plus 15% PRM) must be met by forward commitments at least one year ahead of each summer month (May through September). D.04-10-050 envisioned a RAR that would be phased-in starting in 2005, with the full PRM in place by 2008.

The January Decision (D.04-10-050) recognized that numerous technical details and policy determinations would be necessary before a RAR could be effective, and ordered workshops for the Spring of 2004 on protocols for counting supply and demand resources, deliverability of resources to load, and load forecasting. Eleven workshops were held between March 16 and May 26, and the workshop report was issued on June 15, 2004 (http://www.cpuc.ca.gov/PUBLISHED/REPORT/37456.htm). Although parties were not able to reach consensus on specific language in the Phase 1 workshops, the workshop report noted that there was general agreement in principal that:

> Parties envision that prior to making [a 90% year-ahead forward commitment] showing, (1) the rules regarding forecasting of load and eligibility of resources to "count" towards meeting that load will have been established, and (2) procurement of actual resources will have occurred and been "approved" in some manner, consistent with the policy guidance provided in an adopted long-term procurement plan. If these two elements are in place, the actual showing that an LSE is resource adequate becomes a fairly mechanical and non-controversial demonstration that the forward commitments add up to 90% of the associated load the LSE is responsible for. (Phase 1 Workshop Report, p. 2)

Procurement Must Consider Deliverability For Local & System Reliability

One month after the CPUC posted the Phase 1 Workshop Report, the CPUC focused on the issues related to local area electricity reliability. In July 2004, the CPUC issued D.04-07-028, which addressed the specific problems associated with the lack of deliverable resources in the SP 15 zone. This decision found that Edison's reliance on large volumes of non-deliverable resources was putting stress on the CAISO's real-time operations and jeopardizing system reliability. In considering local reliability challenges posed by constrained transmission limits, D.04-07-028 stated that:

> [a] utility scheduling practice or procurement plan that focuses solely on least cost energy, without regard to deliverability of the procured energy to load or to local reliability, is not in compliance with our prior decisions, approved short-term procurement plans, and Assembly Bill 57.

Resource Adequacy Targets 2006 – Phase 2

In October 2004, the Commission re-evaluated the phase-in approach established in January, and, citing concerns for short term reliability, pulled in the date for RAR, and set a goal of having all LSEs meet their RAR by June 2006 (D.04-10-035) rather than the previously approved phased in approach for RAR compliance by 2008. This accelerated schedule would require all LSEs to meet their entire 15% PRM before the peak summer months of 2006, and would be in place for the CAISO's new market design.

D.04-10-035 identified additional issues that will be necessary for the LSEs to meet the 2006 requirements for Resource Adequacy. The decision moved the RAR implementation into Phase 2, building upon the issues tackled in the Phase 1 Workshop Report and provided that Phase 2 would address further implementation procedures such as narrowing the definitions for:

- LSE's obligation under RAR,
- Specific roles of the CAISO, CPUC, and CEC in ensuring RAR are met,
- Technical details of load forecasting,
- Establishing parameters how various resource types will count towards the RAR, and

- The requirements for reporting, review of compliance filings, and the penalties for non-compliance.

These issues were the focus of the Phase 2 workshops. Phase 2 workshops were organized by topics from the October 2004 decision. Table 2 below provides a cross-reference to where each of the 21 workshop topics is covered in this report.

Nineteen workshops were held in San Francisco, Rancho Cordova and Folsom, facilitated by staff from the CPUC and CEC. The interests of all market participants were represented at the workshops, with participating members from generators, marketers, utilities, ESPs, and consumer advocacy groups. In addition, the CAISO was active and helpful in providing insight into how the RAR would support grid operations and fold into its efforts at market redesign. Appendix A lists the entities that participated in the workshops.

Table 2

Topic Areas In Phase 2 Workshop Report

Topic Number	Topic Area	Chapter (and Section)
Phase I Follow-Up For Load Forecasting Issues		
1	Methodology to identify number of hours for each month that LSEs must meet RAR	Chapter 4, section B; Chapter 5, section A
2	Coincidence adjustments to each LSEs' hourly load forecast	Chapter 4, section B
3	EE/DR impact allocation adjustment methods	Chapter 4, section C
4	Procedures for qualifying hourly impacts of committed EE/DR programs	Chapter 4, section C
5	Hourly loss methodology incorporating dist./trans. losses and UFE	Chapter 4, section E
6	Procedures for including DG in monthly peak load forecasts	Chapter 4, section D
Phase I Follow-Up For Resource Counting Issues		
7	Contract forms that can supplant or supplement LD provisions; audits	Chapter 2, section A.2
8	Methods for determining qualifying capacity of wind and solar w/o gas backup generators	Chapter 5, section G
9	Method for determining qualifying capacity for energy-limited resources in non-summer months	Chapter 5, section H
10	Methods for estimating Commercial-On-Line date for generators	Chapter 5, section I
11	Completion of functional deliverability screening methodology	Chapter 5, section C
Development Of Additional Features From July 8th Ruling And/Or Comments		
12	Month-ahead forward commitment obligations on a year-round basis	Chapter 1; Chapter 2, section A; Chapter 5, section A
13	Development of standard contract language that will require a gen to bid into CAISO's day-ahead market	Chapter 2, section A
14	Load forecasting and resource counting conventions for the month-ahead compliance requirement	Chapter 4; Chapter 5, Chapter 6, section C
15	Local resource adequacy requirements	Chapter 5, section J
16	Allocating DWR contract qualifying capacity to all LSEs	Chapter 5, section F
Reporting, Reviewing, And Sanctions		
17	Load forecasting filing requirements, including provision for historical load, adjustment for EE/DR	Chapter 6, section A
18	Resource tabulations showing how load forecasts and planning reserves are meeting requirements	Chapter 6, section C
19	Review process to ensure LSEs' load forecast are prepared properly, etc.	Chapter 6, section B
20	Specific filing requirements, review process and data access for month-ahead compliance filing	Chapter 6, section E
21	Penalties and sanctions to enforce load forecasts and reserve requirements	Chapter 6, section G

Recent Developments

On February 28, 2005, President Peevey issued an Assigned Commissioner's Ruling informing parties that Commission staff would be evaluating capacity markets and how development of such a market in California might effectively promote achievement of the Commission's goals for resource adequacy and expressed his intentions that any actions taken in Phase 2 of the Resource Adequacy proceeding should allow for the potential development of a capacity market framework. During the Phase 2 workshops, parties discussed various possible market "end states" including issues related to capacity markets. For instance, discussions in the LD workshops briefly touched on end states which ranged from a capacity market to one where LD contracts would continue to be fully used in their current form to meet RAR, the discussion primarily focused on how to incorporate LD contracts in a transition period leading up to an end-state. Parties were very reluctant to discuss specifics of potential end-states. However, while the discussion focused primarily on how to incorporate LD contracts into a RAR framework, some parties did express concern that moving toward a capacity market could create added costs while not necessarily providing additional benefits.

In contrast, in the workshops on issues such as local procurements and compliance, parties agreed that a capacity market would efficiently and effectively implement the resource adequacy requirement. This was especially true in the local procurement workshops where a capacity market could facilitate the efforts of small buyers to meet the RA obligation, larger sellers to sell capacity, and for market monitoring and mitigation to occur.

Chapter 1. Introduction

This workshop report is the result of a series of workshop meetings held from November 2004 through April 2005, as directed by the California Public Utilities Commission in Decision D.04-10-035, “Interim Opinion Regarding Resource Adequacy” (October decision). The decision set forth a series of specific workshop topics to be resolved in a subsequent decision to facilitate meeting the Commission’s goal of ensuring resource adequacy by June 1, 2006. This workshop report is yet another Commission work product articulating a policy preference established much earlier – one which creates a capacity-based approach to meeting the state’s reliability requirements.

From the time of the energy crisis of 2000-2001, the state of California has focused on building up the state’s infrastructure, from revising permitting requirements, to establishing common goals through the Energy Action Plan, and, currently, to establishing resource adequacy requirements. The legislature and the State’s energy agencies strive to assure that California’s energy infrastructure is adequate and meets the State’s economic and environmental goals both now and in the future. The CPUC stated in January 2004 that all load-serving entities (LSEs), including electric service providers (ESPs), would be required and responsible for meeting resource adequacy requirements. The progress to date has been substantial. New power plant capacity totaling 6,700 MW has entered service in California since the end of 2001. Approximately 4,950 MW are under construction, with much of that total scheduled to enter service this year. Several electric transmission projects have been completed, and others are in progress. Finally, the CPUC has promulgated a series of decisions moving toward a resource adequacy requirement for all LSEs.

Despite efforts toward resource adequacy and meeting the CAISO operational requirements, there is considerable work ahead not only with regards to implementation of the resource adequacy requirements, but also with implementation of the CAISO market redesign and assuring the two work seamlessly. While an additional 8,500 MW of capacity has been permitted by the California Energy Commission, it is not under construction and has either been suspended or cancelled, often due to lack of a long term contract or other means, such as a capacity market, to assure that investments will be recovered over the longer term.

The Commission has moved in a consistent direction toward placing greater procurement responsibility on load-serving entities, investor-owned electric utilities and electric service providers alike. It has approved short-term and long-term procurement plans for the utilities. It has already decided that LSEs should maintain a planning reserve margin (PRM) of 15% - 17%. It has decided that this requirement should be in place by June 1, 2006. LSEs must demonstrate 90% compliance for the five summer months a year in advance, which the Commission has defined to mean by September 30 of the preceding year. For the June 1, 2006 mandate, that means a compliance filing on September 30, 2005, (or 90 days after the issuance of the Phase II decision) showing that 90% of the resources required to meet peak loads for the months of June, July, August, September, and October 2006 are already in place. The Commission has already decided that in addition to the annual year-ahead showing for the summer months, all LSEs must demonstrate full compliance with the 15% - 17% PRM on a month-ahead basis for every month of the year. The Commission has already adopted a series of policies that constitute a general framework for RAR. These include protocols for forecasting the LSE loads, conventions for counting resources, and aggregate and local deliverability requirements.

The Commission established in its October 2004 Resource Adequacy decision a capacity-based resource adequacy obligation: "[T]hese requirements are established for purposes of inducing forward commitments with resources that are appropriate to satisfying a 15% - 17% benchmark for a summer peak capacity metric. Prospective restrictions … are all part of creating a capacity-oriented resource adequacy requirement."[2] The Commission laid out additional steps to ensure that a year-round resource adequacy requirement could be defined and enforced, including outlining a series of topics to be considered in Phase 2 workshops. This workshop report is a direct result of that decision. The October decision further states that "Beyond Phase 2, there are 'second generation' topics that need to be revisited or added to our initial generation of resource adequacy requirements."[3] Those topics include proposals related to capacity trading, multi-year forward commitment, and resource tagging and trading.

The Commission has thus adopted, and now must implement a capacity-based system of resource adequacy requirements. This workshop report addresses issues that pertain to the long-

[2] Decision 04-10-035, "Interim Opinion Regarding Resource Adequacy," section 3.10, page 45.

[3] Ibid. Section 4.2, p. 48.

term foundational elements as well as transitional features that may be required until the end state is established. That is, while this report provides the record to implement transitional features of the resources adequacy construct, it is important for parties to understand the end state toward which the CPUC continues to advance. That end state is a capacity-based resource adequacy system. Consistent with that direction, the Assignment Commissioner in this proceeding issued a ruling earlier this year providing guidance that the outcome of this proceeding is intended to be consistent with the development of capacity markets.

What is Resource Adequacy? And Why a Resource Adequacy Requirement?

Resource adequacy, combined with availability, ensures the security and reliability of the electric system. Additionally, as discussed above, resource adequacy refers to "building the states infrastructure." There must be enough resources to meet customer needs (adequacy), and enough of that capacity must be available when it is required (security). Resource Adequacy Requirements is the tool the Commission is using to accomplish these two related results. First, RAR, as its name implies, ensures adequacy – that is, it ensures that the physical infrastructure will exist. This is the first component included in the engineering concept of reliability. Having an adequate supply of capacity makes security, the second component of reliability, possible. Technically, this is all that is required of a Resource Adequacy Requirement. But by careful design, that requirement can also contribute to converting the possibility of security into actual security. This is not the primary objective of a RAR and it should be remembered that even with the best RAR, security will remain the primary responsibility of the energy and ancillary services markets because these are real-time markets and security is a real-time characteristic. Generally, security of the system is maintained through the commitment of resources to the CAISO's day-ahead, hour-ahead, and real-time systems. Second, resource adequacy should ensure that the system provides adequate infrastructure on an ongoing basis. This second responsibility falls on LSEs and is enforced. In simple terms, the load must be served from the resources that exist, and there must be sufficient resources on the system.

Most of the time the electric system does not require every piece of generating equipment to be in operation or even to be prepared to operate on a moment's notice. That means that some resources will be called upon to operate only rarely or, conceivably, not at all for extended periods of time. However, when conditions require it, such as a dry hydro year or during peak summer conditions, resources in adequate number must be available for operation to meet customer needs. Who will invest in such resources, maintain them in readiness, and wait to operate only rarely? If generators receive payment only for the energy they produce but cannot recover fixed costs incurred whether they operate or not, investments in capacity will not be made. This is especially the case if there is a limit on how much generators would be allowed to charge for the energy they provide even in conditions of extreme scarcity. Yet clearly, California will not have adequate resources and system reliability if existing resources are not adequately compensated. Furthermore, no new resources will come into existence if they cannot be adequately compensated.

Ultimately, the LSEs that serve consumers must pay for the generating resources[4] that provide resource adequacy. Resource adequacy, both current system reliability and adequacy of investment, are necessary components of customer service. Yet resource adequacy is a feature of the entire electric system, not a feature of individual customer service or of individual LSE service. A resource-adequate system, one in which reliable service is secure and in which adequate investment continues to occur can be expected to be more costly than one which is not resource-adequate. Alternatively, the costs of blackouts or the effects of a lack of security can be high as well. Because some generators are unable to recover sufficient costs from a capped energy-based market, they must be compensated through a RAR mechanism. This replacement mechanism must be sufficient to cover capital and maintenance costs on an ongoing basis and a surety of future investment dollars. Each LSE would prefer that some other LSE shouldered a heavier portion of the burden so that its own costs could be lower. Therefore RAR must be administered and enforced for the system as a whole. The Commission has required LSEs to demonstrate that they are resource adequate; the result will be system-wide resource adequacy. RAR is to be based on appropriate contracting methods, commitment of available generating capacity, deliverability of resources to load areas, and adequate investment additions and maintenance of the current supply of generating capacity. All of these elements are necessary for

[4] Within the framework of a CPUC-imposed resource adequacy, LSEs must continue to satisfy the loading order initially established in the Energy Action Plan with respect to Energy Efficiency, Demand Response, and Renewables.

the resource adequacy requirements to work together to achieve a desired level of reliability. One cannot expect to have a highly reliable system and not pay the necessary costs.

This report covers a number of issues upon which the Commission must decide for the implementation of the resource adequacy requirement by June 1, 2006, and, even more pressing, for the demonstration of 90% compliance by September 30, 2005 (or 90 days after the issuance of the Phase II decision). There are issues relating to load forecasting and coincidence adjustment; quantification of energy efficiency and demand response and adjustments for distributed generation; electric system losses; deliverability issues; appropriate contracting methods and limitations; accounting for limited-energy resources and intermittent resources; local resource adequacy requirements; and reporting, review, and sanctions requirements. Most of these issues face little controversy. The Commission must also evaluate and choose between two conceptually different types of systems under which all of these individual policies will be implemented. Those two systems, which have been given the short-hand names "top-down" and "bottom-up," may have very similar features in practice, but different conceptual underpinnings, and they point to different views of what resource adequacy is, how it should be implemented, and what kind of resource adequacy system will be in effect in the long run.

Chapter 2. Nature Of The Obligation

This Chapter examines what the CPUC policy of a "RAR" (RAR) will mean in terms of the obligations it may place on market participants. Of utmost importance are the following:

1. **the obligations RAR will place on LSEs and generators,**
2. **the roles of California's energy entities (the CAISO, CEC, and CPUC),**
3. **how various resources may be used by LSEs to meet the RAR, and**
4. **the use of forecasts in developing the amount of resources the LSEs must procure.**

2.A. Obligation Of Load Serving Entities And Generators

D.04-10-035 established a LSE-based obligation to meet resource adequacy requirements. One of the reasons for this approach is that the Commission does not have relevant jurisdiction over the suppliers that will be contracting with LSEs that must meet the RAR. Such an approach means that the RAR obligation would be entirely on the LSE and the LSEs in turn would place requirements on generators via their capacity contracts with those entities. In an effort to guide the LSEs to that end, the Order highlighted broad aspects of the contractual obligations LSEs were to impose on generators. These obligations included a generator obligation to be scheduled by the LSE, then bid into the forthcoming day-ahead market if not already scheduled, and subject to the CAISO Residual Unit Commitment (RUC) process.[5] The Commission further stated that contracts executed after the Phase 2 decision should include contract provisions that would have an obligation on the generator to respond to CAISO instructions when called upon to serve load in order to be eligible to count as qualified capacity for forward commitment obligations.

The October order also determined that compliance, reporting, and sanctions be established in the phase 2 workshops. The workshop on these issues occurred on January 12,

[5] These references were made in anticipation of the CAISO's market redesign becoming effective in February 2007. In the transition until that time, RAR resources would have to be scheduled day ahead.

2005. While most aspects of reporting, compliance, and sanctions were resolved as discussed further below, the overarching problem that arose was that an LSE-only RA obligation would not only fail to achieve critical RA security objectives, such as performance and compliance, but also unfairly burden load with the entire RA obligation. LSEs argued that generators that want to qualify to be a RA resource should also have obligations under the RAR. LSEs highlighted several key implementation problems stemming from the LSE-only obligation including a lack of visibility in the market to know whether resources it contracted for actually performed. Furthermore, LSEs objected to the notion that load would be subject to sanctions if the supplier failed to perform.

Inherent in the LSE-only approach is the premise that LSEs will enforce generator performance and compliance via their capacity contract. This assumes that the CAISO will somehow know to inform the LSE that their particular contract did not perform.[6] Under that construct, the LSE would then have to pursue damages for contract breach, probably in litigation or a dispute resolution process. Neither load nor suppliers supported the LSE-based approach since the ambiguity regarding the nature of the obligation and the means to demonstrate compliance would likely result in foggy rules that were likely to introduce litigation risk for both sides of the RA contract. All workshop participants recognized that a LSE-only RA obligation was both an unfair burden on load as well as fraught with practical implementation problems.

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

In response to the issues raised in the initial workshop on compliance, CPUC staff and the CAISO developed a working proposal that splits the RA obligation between generators and LSEs. The working proposal was discussed in the workshop on February 16, 2005, and is summarized and discussed in this section. There was consensus among workshop participants that the alternative approach of splitting the obligation between LSE and supplier resolved many

[6] Under the construct where a LSE contracts for physical capacity resource to meet the RAR, compliance is simplier to conduct both in the existing market structure and when market redesign is implemented. However, for contract energy where specific generators are not identified, the current balanced schedule requirement effectively forces the contract to become physical in the day ahead scheduling timeframe. Once the market redesign is implement and the balanced schedule requirement is eliminated it will be very difficult to know whether the supplier performed under the contract.

of the implementation and fairness issues raised earlier, and provided overall more benefits and better incentives than the LSE-only approach.

While the Commission's RAR will apply directly to LSEs, the effect of resource adequacy obligations will apply to generators and LSEs as well. The generators will have to meet minimum criteria to qualify to be a capacity resource to fulfill the RAR; and LSEs must submit filings that demonstrate that they have met the 15%-17% planning reserve requirement.

An LSE's obligation is to show to the CAISO and CPUC in the year and month-ahead timeframe that the required reserve amount was bought. This could be accomplished by the LSE providing a contract reference number.[7] The LSE would report the amount of capacity purchased and the capacity provider information (i.e. no price information) to the CAISO and/or CPUC. Next, LSEs must obligate the seller to abide by the requirements in the CAISO tariff that the generator must meet. Finally, LSEs will be subject to sanctions for non-compliance as specified below.

A generator that wants to qualify to be a RA resource must:

1. be available for testing by the CAISO to determine qualifying capacity,[8]
2. have its qualifying capacity linked to performance (i.e. forced outages impact the next year's or period's qualification),
3. be included on the CAISO's "listing" of qualified capacity so the CAISO can make an accounting against the LSEs' submittals,
4. bid into the CAISO's forthcoming day-ahead market,[9]

[7] Using a template with contract reference number will simplify the showing but will require a third party, or the CAISO, to conduct contract audits as needed.

[8] Nameplate capacity is a poor indicator of the actual capacity a generator is capable of supplying. For this reason, other ISOs test generators, usually seasonally, to analyze the generators' real ability to perform. This information helps LSEs to know what the capacity is worth when signing capacity contracts.

[9] Preliminary Description of Generator Availability Requirement :
Under the present CAISO tariff procedures, the Seller's availability obligation consists of the following if the Contract Quantity is not scheduled or declared inoperable: The Seller must make the Contract Quantity available to the CAISO on a must-offer basis unless granted a waiver via the Must Offer Waiver Denial process day-ahead, in which case the Seller is released of any further obligation; provided, however, that if the capacity consists of a unit or units with under 5 hour start times ("Short-Start Units"), the Seller remains obligated to make the Contract Quantity available to the CAISO on a must-offer basis

5. be subject to pay CAISO sanctions for non-performance, such as Uninstructed Deviation Penalties.

Based on the obligations outlined above, workshop participants made several additional points. First, that the generators' obligation should be outlined in its Participating Generator Agreement (PGA) or some other agreement. LSEs agreed that it is far easier to simply reference the RA resource's standardized obligation under the CAISO's PGA in the RA contract. Most agreed that an agreement separate from the PGA may be preferable since not all generators with PGAs will be RA resources. For consistency, the definition of a RA resource in the CAISO tariff should mirror the CPUC definition.

Some participants made an argument that if an LSE contracts with a RA resource for the "qualified capacity" that the CAISO lists in a particular year, that capacity should "count" for the life of the agreement, even if that capacity is de-rated during that period due to performance. For example, if the CAISO determines that a generator qualifies for 100 MW of capacity in year one and a LSE signs a three year contract for the entire 100 MW, the 100 MW should count for the three year period even if the CAISO determined in year 2 or 3 that based on the performance in year one the generator is only listed for 75 MW. According to these parties, not counting the contract capacity for the term of the contract would undermine objectives of longer-term contracting. In addition, de-rating generation capacity is unlikely to be a significant issue as the generator will have an incentive to maintain the generation and perform if it wants to remain eligible to participate in the market as a capacity resource. The opposite view is that creating a

same-day subject to the start time of the unit. Compensation for operating at minimum load and, if required, for start-up in response to a Must Offer Waiver Denial is cost-based.

Under MRTU, the <u>proposed</u> CAISO procedures, the Seller's availability obligation would be as follows if the Contract Quantity is not scheduled or declared inoperable: The Seller is obligated to submit a "three-part" bid for the Contract Quantity into the day-ahead "Integrated Forward Market" ("IFM") to be committed and scheduled by the CAISO for energy or ancillary services. The unit's energy and ancillary services capacity bids may be submitted at any price subject to market power mitigation procedures. However, the start up and minimum load parts of the three-part bid must be either cost based or fixed for 6 months. If not selected, the Seller's bid would carry over to the day-ahead Residual Unit Commitment (RUC) process. If the Seller's bid is not selected in the day-ahead RUC process the Seller is released of any further obligation with the exception of Short-Start Units. For Short-Start Units, the Seller's bid would then carry over to the same-day RUC process that occurs as part of the Hour Ahead Scheduling Process (HASP) and the bid may be updated by the Seller.

fixed level of qualifying capacity gives the resource a “free ride” irrespective of performance during the entire life of the agreement or performance at critical hours. Not only would this create disincentives for the resource to perform, it diminishes responsibility of the LSE to make a good choice from among available resources

All workshop participants agreed that (1) if performance (e.g. forced outage rates) is accounted for in determining qualified capacity, then the overall reserve margin should be adjusted accordingly, (2) if average forced outage rates go down, as a result of tying the eligibility as a capacity resources to performance, then the overall reserve requirement should be reduced, and (3) if average forced outage rates are high, then a higher reserve requirement is justified.

Workshop participants further agreed that for at least the first year the reserve requirement should remain at 15%-17%, but it may warrant adjustment after gaining experience with measuring performance of RA resources. All workshop participants agreed that linking eligibility to be a capacity resource to the prior year’s performance would not only provide better incentives for generators to maintain and invest in resources, but also benefit consumers who may otherwise be overpaying for unreliable capacity. Conversely, if a resource makes investments to increase capacity, its capacity contribution should be recalculated to incorporate the upgrades. If the reserve requirement is adjusted to reflect more reliable generating units, consumers benefits from the lower reserve requirements.

There was consensus among workshop participants that the alternative approach of creating a direct obligation of the supplier to the CAISO resolved many of the implementation and fairness issues raised earlier, and despite some implementation drawbacks, provided overall more benefits and better incentives than the LSE-only approach.[10]

[10] In determining that the RA obligation should apply to both LSEs and suppliers, the Commission would be recognizing the CAISO’s pivotal role in RAR implementation since the CAISO is in the best position to impose and enforce certain requirements on the suppliers. The CAISO is the only entity that can know whether a generator has performed and met its RA obligation as well as conduct the level of analysis and testing to determine how much capacity a particular generating unit can produce. Including an obligation on generators that want to qualify to meet the LSEs’ RAR should result in the proper incentives to invest in generating units and improve performance and thus potentially reduce the overall reserve requirement. The CAISO indicated at its March 1 technical conference on market design its plan to include such a proposal either in its April conceptual market design proposal to FERC or its November tariff filing.

Advantages of this approach are:

1. The RAR obligation is distributed between LSEs and suppliers
2. Qualifying capacity and the associated eligibility for capacity payments is linked to performance of individual resources
3. It is practical for purposes of reporting and sanctions since the CAISO is the only entity with the ability to know whether a generator has met its obligation and showed up in the market
4. Qualification to be a RA resource should provide an incentive for plant investments/upgrades and a reduction in forced outage rates thus holding the potential to lower the overall reserve requirement and costs.
5. Provides a more effective means of enforcement than an LSE-only obligation
6. Since the generator's qualifying capacity will be listed by the CAISO based on its performance and testing, LSEs will have better information regarding the value of the capacity when making purchases.
7. This approach is more consistent with the pricing and transmission service rules established in FERC's Standardized Interconnection Rules.[11]
8. The approach builds on the experience in the Eastern markets that have administratively established capacity markets.

Disadvantages of this approach include:

1. May require more coordination between the CAISO and the CPUC
2. The specific means to measure performance and the process for determining the qualifying capacity has not yet been defined by the CAISO
3. A testing-based method for determining qualifying capacity for individual generators has not been developed and cannot be implemented in this initial compliance cycle for 2006 RA obligations.

[11] Order 2003 establishing standardized interconnection rules allows independent entities, such as the CAISO, to develop two levels of transmission service- one for energy, which is an 'as available' service. The second is a higher quality transmission service for capacity resources deliverable under peak conditions. If generators want to qualify as a capacity resource, they must fund the necessary network upgrades to assure their resources are deliverable at peak. See 104 FERC 61.103.

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

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

2.A.2. SVMG Standards Contract Language

In response to Commission guidance, Silicon Valley Manufacturer's Group (SVMG) offered a proposal for a standalone resource adequacy capacity product that it believes could be used to meet the Commission's RAR. SVMG's proposal would (1) allow the buyer to count capacity towards RAR, (2) allow the seller to retain ownership and/or control of the capacity, (3) qualify the contract capacity, (4) ensure that capacity is not double-counted, (5) require the seller to make its resource available to the CAISO for all hours of the delivery period in the contract. In the Phase 1 decision, the Commission addressed the development of a capacity-only market. It noted that:

> …standard terms and conditions applicable to new contracts are the core requirements of readily transferable capacity-only contracts. Some parties advocate the creation of mandatory, centralized capacity markets, but this is infeasible in the timeframe for our September 30, 2005 compliance filing. We believe a readily traded capacity contract that parties can voluntarily exchange is a useful first step. Such contracts can address most of the issues parties have raised in terms of the "best estimates" versus "current customer" basis for LSE load forecasts. (D.04-10-035, p. 43).

2.A.2.1. SVMG's Proposal As A Complement To The CPUC Staff / CAISO Obligation Proposal

After extensive discussion in a sub-working group developing the proposed contract language, SVMG presented a Working Proposal on the "Standalone Resource Adequacy Capacity product' for discussion at the February 16, 2005 workshop (see Appendix B). The discussion of the proposal followed the workshop discussion of the CPUC staff/ CAISO proposal to split the RA obligation among generators and LSEs and the consensus among parties that such as approach was preferable. Therefore, the discussion of the SVMG proposal took place in that context. While the CPUC staff/ CAISO proposal establishes a short and long-term obligation for generators and LSEs, the SVMG proposal is only applicable to the period until implementation of the CAISO's market design because it is viewed as a replacement to FERC's Must-Offer. Parties supported the SVMG working proposal and there was agreement among parties that the SVMG proposal is consistent with the CPUC staff /CAISO proposal. The main issues discussed and resolved are detailed below.

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

The SVMG proposal entails that generating units procured under the SVMG capacity-only product and identified as contributing to an LSE's RAR be bid or be scheduled in the day-ahead timeframe. In the time period between when RA is implemented in June 2006 and when the CAISO implements MRTU, the SVMG proposal assumes that the units will be committed by the CAISO in the only day-ahead market available to the CAISO: the ancillary services (AS) market. However, the CAISO has stated that its ancillary services market is an inappropriate mechanism for reserve capacity to be bid and scheduled by the CAISO because using the AS market to dispatch RA resources assumes the units are already on-line (i.e. committed).

Currently, FERC's must offer waiver denial process provides a mechanism for generators to bid and for the CAISO to be able to dispatch non-self-scheduled resources on a day-ahead basis. In order for the CAISO to have a mechanism to commit resource adequacy units that are not scheduled by an LSE, it may be necessary to maintain the must-offer process until the implementation of MRTU beyond June 2006. This is because if the must-offer and the associated waiver process is eliminated upon implementation of resource adequacy, the CAISO will not have any other means to commit RA resources (whether procured under a stand-alone capacity product or otherwise) for the next day until it implements a day-ahead market as part of its MRTU proposal in February 2007. Staff notes that although the must-offer mechanism may be required prior to implementation of MRTU to assure dispatch of RA resources, and that such a mechanism may require cost information from suppliers in order for the CAISO to most efficiently select necessary resources, existing must-offer compensation may duplicate payments under RA contractual arrangements. Appropriate adjustments to must-offer compensation for RA resources should be considered.

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

With regard to energy-limited resources, the SVMG proposal provides for the optimal dispatch and use of these resources to be outlined by the CAISO in the MRTU process. Energy limited resources would only have to be available in the month they are "counted" towards the RAR. The CAISO usage protocols that they develop with the LSE will guide the use/ dispatch of those resources in the month they are counted. Most workshop participants agreed with this approach.

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

2.B. Counting Conventions That Support The Obligation

The Commission has chosen to count physical resources, but of course not all physical resources are alike. While LSEs face an obligation to provide resources to the system, the differences among types of resources means that the qualities they bring to reliability are different. For counting purposes, the obligation LSEs face is to provide resources that can be counted upon to serve loads. Not all types of generating resources are able to provide service when called upon, or provide continuous service over long periods. Resources still under construction, similarly, do not have the same reliability-enhancing abilities as resources already in service. Because the obligation is to provide reliability to the system, it is necessary to develop counting conventions for such resources with care to prevent over-counting of their contribution to the system and, hence, overconfidence in the reliability of the system. Chapter 5 addresses the counting conventions for specific types of resources.

Chapter 3. Interagency Coordination

The CAISO, CEC, and CPUC, in concert with FERC, must work together to meet the policy objectives of Resource Adequacy while minimizing ratepayer costs. Each agency will play a role based upon its expertise and jurisdiction. This Chapter covers the various roles that these agencies must cover.

3.A. Review Of Load Serving Entities' Load Forecasts & Compliance Filings

D.04-10-035 suggests possible roles for the CEC and CAISO in supporting the implementation of the RAR. D.04-10-035 explicitly calls for the CEC to review LSE load forecasts. This role has been further clarified in workshop discussions and issues associated with the mechanics of this cooperative effort are spelled out in some detail in Section 6.A of this workshop report.

The workshop process revealed the necessity of a CAISO role in resource adequacy compliance and enforcement in addition to their critical role in conducting deliverability analysis and developing local procurement requirements. The balance of this section discusses the collaboration of the CEC and CAISO in carrying out these roles.

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

In the Phase I workshop Report, the parties discussed the option of the CEC collaborating in the implementation of RA by reviewing load forecasts. This is an expertise for which the CEC is well known, and the CEC accepted this role as documented in D.04-10-035.

In carrying out this role CEC expects to play a technical role in reviewing preliminary load forecasts for plausibility, in determining coincidence of individual LSE load forecasts with that of the system, in adjusting these preliminary load forecasts for various factors that cannot readily be addressed by all LSEs. Should the CEC finds that LSE forecasts are inadequate, the CEC is expected to pursue resolution of problems at a technical level since it does not have the authority to impose sanctions. Therefore, in the event that the CEC finds the LSE forecast unsatisfactory, it can inform the CPUC so that appropriate sanctions can be imposed.

Workshop participants raised several issues regarding the approach of having the CEC adjust LSE forecasts, which could then lead to potential sanctions for non-compliance. For example, how will the CEC know the difference between legitimate forecast error and deliberate under-forecasting? If LSEs are to be sanctioned based on the accuracy of their individual forecast, the Commission should specify the triggers for sanctions upfront. Since the CEC may adjust LSE forecasts, parties requested a specified process for dispute resolution if the LSE disagrees with the CEC's findings. Furthermore, if LSEs may be sanctioned based on their forecasting error, LSEs requested a formal adoption of the forecasts and the associated RA obligation that stems from it as protection against after-the-fact questions about whether LSEs complied with the RAR and are subject to sanctions.

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

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

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

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

3.A.2. CAISO & CEC Review Of Compliance Filings

A substantial implementation effort is needed for the resource adequacy requirement. The CAISO would likely have a central role in implementing and enforcing the RAR because of its day-to-day operational visibility of market behavior and its ability to monitor the operation and performance of generators.

The annual compliance filings for Year-Ahead obligations require a review that focuses on the qualifying capacity that LSEs identify to meet the load forecast that was reviewed and adjusted by the CEC (See section 6.B. for details). This review seeks to assure that each LSE follows the requirements for counting qualifying capacity of resources, determining that resources have not been double-counted by more than one LSE, and verification that the totality of resources submitted by numerous LSEs are actually deliverable to load. The CAISO must review and analyze the year-ahead data given its role in backstop local reliability procurement. Therefore, both the CEC and CAISO must have access to the year-ahead reporting to conduct the responsibilities outlined in this report.

D.04-10-035 adopts a month-ahead forward commitment obligation that requires LSEs to "fill up" the balance of their commitment obligations from those identified on a year-ahead basis for the five summer months and to present documentation to demonstrate that they have acquired the resources to fully cover their expected loads and reserve requirements for the other seven months. As discussed further in section 5.J., in order for the CAISO to supplemental procurement in local areas, 100% of local procurement requirement should be met a year in advance. In the short time between these month-ahead filings and actual system operations there are limited opportunities to acquire additional resources, if analyses dictate that this is warranted. The CAISO's responsibilities to ensure system reliability become much more pronounced as the planning timeframe shrinks; therefore, it is reasonable to expect that the CAISO should play a substantial role in the review of the LSEs' Month-Ahead filings. Participation in enforcement by the CAISO in the month-ahead timeframe is consistent with the responsibilities it would have in the event there is a monthly capacity market.

Sections 6.D. and 6.E. outline specific reporting and sanction issues that the Commission must decide.

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

D.04-10-035 expressed concern with potential "gaming" of load forecasts, and stated that the CPUC should be watchful for attempts to submit load forecasts lower than actual loads thus reducing the amount and cost of qualifying resources compared to those that ought to have been secured.

The CEC is the natural entity to undertake this sort of analysis, and the CEC and the CAISO should coordinate their technical expertise for the necessary data to be transferred from the CAISO to the CEC in a timely manner. Appropriate confidentiality exchange protocols and secure data storage mechanisms should be employed in this effort.

The CAISO itself may be the most appropriate entity to review the performance of resources nominated by LSEs since it is uniquely aware of the physical attributes of California generators, their use through the Day Ahead scheduling process, and any downstream unit commitment and dispatch instructions that were issued even if not scheduled by the LSE. As discussed in section 6.F., the CAISO should have a pivotal role in compliance and sanctions given its visibility in the markets and more "real-time" ability to react and impose sanctions for those failing to comply with RA obligations.

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

3.B. Coordination Of CAISO Tariff-Based Requirements With CPUC Requirements

The previous subsection discussed how the CEC and CAISO act as partners to the CPUC in certain implementation tasks when RAR are established. This subsection addresses the more substantive issue of the actual coordination of CAISO tariff requirements with those that the CPUC itself can enact so as to have a package of RAR that combines the authority of both entities.

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

The CAISO's proposed process for determining the local procurement requirements would take place in its transmission planning process. Since local requirements are an artifact of transmission constraints and the local reliability criteria, the planning process is a natural place for this analysis to occur. While the CAISO currently does similar analysis in its RMR determination, development of the local requirements would presumably require modification of the process to coincide with the annual RA timeline. It seems that this process, at a minimum, would require a formal description of the process in the CAISO procedures and protocols for participation by stakeholders. The CAISO would also have to outline its process for dealing with disputes that stem from the local requirements determination. This may require changes to the CAISO tariff and/or procedures.

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

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

Currently, the CAISO relies on RMR contracts to satisfy local reliability requirements. While they were originally envisioned as a means to support the transmission system in critical locations in California, they have come to be used to a much larger extent than anticipated. The CPUC has determined in various Commission decisions that the use of RMR contracts should, instead, be replaced with resource adequacy requirements. As outlined in Section 5.J., there exists implementation hurdles for local procurement requirements as we transition to a fully established capacity market. In addition, given the timing of the current RMR (LARS) designation process and implementation of RA in June 2006, RMR contracts will continue through 2006. At its May 17, 2005, LARS meeting, the CAISO raised the issue about how to transition out of today's RMR designation process to an LSE-based local procurement as the CAISO serves a "backstop" role in the local area procurement. The CAISO continues to develop the backstop capacity contract and has included such a contract conceptually into its May MRTU filing to the FERC. Nevertheless, the process of developing that contract continues and will require coordination and cooperation in the coming month. As discussed in Section 5.J.4.2., it is critical that the allocation of costs associated with the CAISO's backstop role be consistent with cost causation principles in order to provide the correct incentives for LSEs to assure that the CAISO remains a true backstop.

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

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

D.04-10-035 makes clear that resources must ultimately be available to the CAISO when they are needed. Phase 2 workshops have principally discussed this issue in the context of the contractual language obligations that at least would be placed upon generating resources, if not all resources, to obligate them to follow CAISO requirements. Less discussion has been held on the specifics of how the CAISO would actually call upon such resources, the extent of these obligations, hierarchies of triggering conditions applicable to various categories of resources, etc. This issue highlights the importance of CPUC/CAISO coordination in developing tariff language and operating procedures that would replace the existing "must offer" requirements. As a consequence of FERC authority over the CAISO tariff, all of the CPUC, CAISO and FERC must cooperate in the development of a complete RA package. While this should not be news to anyone tracking developments at FERC concerning RA and CAISO market design, it is restated here to remind parties that a substantial implementation step remains incomplete and must go forward with cooperation of the CPUC and CAISO to ensure integration of LSE actions and market developments.

While FERC has stated that the existing must-offer obligation sunsets upon implementation of the CPUC RAR, FERC has not been explicit about when it will deem the CPUC RAR "fully implemented." Suppliers in particular objected to the continuation of the

FERC must-offer obligation for non-RA resources if there is a gap between when the CPUC implements resource adequacy and the FERC terminates the existing must-offer.[12] The suppliers assert that the continuation of the FERC must-offer undermines the incentive to contract for capacity since that capacity is available for free under the FERC's mandate. While the workshop moderator pointed out that CPUC has no authority with regard to the FERC must-offer requirement, most workshop participants agreed that a declaration by the Commission that RA is "fully implemented" would be helpful in providing clarity in relation to FERC. The SVMG standard contract language, discussed below, only addresses RA contracts in the interim until the CAISO's new market, known as MRTU, is implemented in February 2007. Section IV of the SVMG proposed language addresses how the existing FERC must-offer is supplanted by the CPUC RAR.

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

The Commission needs to be clear that resource adequacy requirements will replace FERC-imposed must-offer obligations.

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

To the extent the CAISO is to become the keeper of a centralized capacity listing process for those resources authorized to be used as qualifying capacity in these resource adequacy requirements, then the CAISO will have to devote resources to this activity. The joint CPUC staff / CAISO proposal also suggest that testing eventually be a part of this resource-specific qualifying capacity determination. Testing protocols and schedules will have to be developed. The CAISO will have to modify its tariff to undertake these tasks and FERC must approve such

[12] If the FERC terminates the existing must-offer in February 2007 when the CAISO's market re-design is scheduled to be implemented, there will be an 8 month gap between the CPUC June 2006 RA implementation and the introduction of the CAISO's new market.

changes. The CAISO must also allocate appropriate resources to implement these activities in a capable and timely manner.

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

3.C. CPUC And CAISO Coordination With FERC

The implementation of the RAR, in concert with the CAISO's introduction of revised market design rules will require both agencies to work closely with the FERC. Most critically, the California market will rely upon FERC adopting a local market power mitigation that supports the CPUC's locational procurement requirements.

The CPUC and CAISO will need to coordinate to ensure that the intent of the CPUC policy decisions is appropriately reflected in the tariffs the CAISO files with FERC.

Chapter 4. Load Forecasting

To maintain adequacy of supply in the future, the grid operator and LSEs must have good information about anticipated demand. The use of load forecasts is therefore an important part of any RAR Framework.

This Chapter examines the load forecasts the LSEs will use to plan for and meet their Year-Ahead RAR. The Phase 2 workshops had detailed and technical discussions to clarify issues about the forecasts LSEs will prepare, and how local reliability and deliverability concerns would be incorporated into forecasts.

4.A. Load Serving Entity-Specific Load Forecasting

D.04-10-035 established an approach to resource adequacy that depends upon individual LSEs developing their own load forecasts, acquiring the resources needed to satisfy these forecasts through two stages of requirements to secure forward commitments to qualifying capacity resources, and a compliance filing review process. Broad direction in the preparation and submission of load forecasts for review was settled in Phase 1. Phase 2 included several specific implementation issues unresolved in the Phase 1 decision. These follow-up topics included:

1. Focus for LSE load forecasting efforts
2. Coincidence adjustments to individual LSE loads
3. Attribution of energy efficiency ("EE"), DR and distributed generation ("DG") impacts to individual LSEs
4. Preparation of hourly impacts of EE, DR and DG necessary for hourly load forecasts.
5. Development of a total losses methodology to comport with the planning convention that peak loads include such losses.

Further, load forecasts were to be developed in two stages. A preliminary load forecast was to be prepared and submitted with documentation by each LSE to the CEC in the spring of each year. The CEC is to review these for plausibility and consistency, in the aggregate, with load forecasts prepared by itself and/or the CAISO. They are also to be adjusted by the CEC for programmatic impacts (such as energy efficiency and demand response) and coincidence. After the CEC analysis is complete, the CEC will provide the LSE with its adjusted load forecast to serve as the basis for the qualifying capacity obligation and the compliance filing due each September 30 for the subsequent year. Finally, the workshops raised issues about whether the year-Ahead load forecasts could, or should, be updated with Month-Ahead compliance filings. This final issue is discussed in Chapter 7 of this report.

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

D.04-10-035 partially established requirements for the load forecast that is the foundation for the quantitative requirements for qualifying capacity. Some issues were settled, such as whether the load forecast should be based on current customers or a "best efforts" basis to forecast future customers and their load. D.04-10-035 endorsed the "best estimate" approach.[13] The focus is on an accurate load forecast.

The adjustment process cannot be implemented except using hourly load forecasts and hourly program impacts. Irrespective of the final resolution of the issues of the resource obligation to be available to the CAISO and the precise definition of the LSE's loads to which a planning reserve margin is added and resources are shown to cover with qualifying capacity, hourly load forecasts from each LSE are required.

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

[13] Despite this firm direction, Constellation/New Energy introduced a "load migration" proposal that would "freeze" customers for which the LSE was responsible irrespective of which LSE actually served their energy requirements in the various months of the forthcoming year. CLECA, CMTA, and APS Energy Services formally opposed the Constellation proposal in written comments. The topic was discussed in the February 16, 2005 workshop. The topic will not be pursued in this workshop report.

4.B. Coincidence Adjustment Methodology

D.04-10-035, Section 3.4.1 is clear that LSE obligations rest upon coincident peaks rather than the unadjusted peaks of each LSE.[14] Two approaches were discussed at the original scoping workshop on November 30, 2004. First, those associated with using historic coincident factors and, second, those associated with determining coincident peaks directly from the hourly load forecasts submitted by the LSEs.

Coincidence methods that use historic factors have advantages and disadvantages. Advantages include the ability of each LSE to perform the adjustment themselves rather than having this adjustment take place as part of the CEC's review of preliminary LSE load forecasts. The disadvantage is the lower degree of accuracy compared to other methods that determine control area peaks directly from a summation of adjusted final LSE-specific hourly load forecasts.

Coincidence adjustments based on direct computations of total load by summation of the final load forecasts of each LSE clearly are more accurate. They can take into account the impacts of the programmatic adjustments that the CEC will make for EE, DR, and DG impacts. They can take into account the natural evolution of load shapes as each LSE's customer base changes, or as the shapes of loads of individual customers change. However, it should be noted that the disadvantage of this approach is the mirror image of the previous one. Clearly greater degrees of change from LSE-specific preliminary load forecasts to final CEC authorized final load forecasts diminishes the ability of an LSE to "guesstimate" what its obligation will be, thus reducing the willingness of the LSE to undertake commitments of resources using preliminary load forecasts. Commitments to resources may be shifted later in time. A forecast-based coincidence adjustment must also either wait until all LSE load forecasts have been submitted or have contingencies to determine coincidence on the basis of "default" mechanisms that can be implemented if one or more LSEs fails to submit acceptable information.

Staff notes that because DR and DG operated as peak shaving technologies are explicitly designed to affect peak loads more than off-peak loads, aggregate and individual LSE load

[14] At least one of the "top-down" descriptions received on May 10, 2005 proposes to use the LSE's own non-coincident peak for each month.

shapes will change as a direct result of actions to achieve these policy goals. RAR implementation mechanisms ought to be sensitive to the beneficial impacts of these policy initiatives since D.04-10-035 established a policy that DR program impacts should count toward compliance. To the extent that such impacts are more crudely counted in establishing the obligation then these resources are less cost-effective than they might otherwise be. Further, avoiding cost-shifting is most fully achieved with methods that directly develop peak loads from summation of final LSE load forecasts.

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

- *Methods using historic data, perhaps from one or more years, that can be implemented by LSEs as part of the preparation of preliminary load forecasts,*
- *Methods using LSE-specific preliminary hourly load forecasts that are implemented by the CEC as part of its review of preliminary load forecasts.*

4.C. Quantification And Allocation Of Energy Efficiency & Demand Response And Adjustments For Distributed Generation

Energy efficiency, demand response and distributed generation programs have been funded mainly as IOU programs, but also to a limited extent as energy agency-sponsored programs. They have received considerable attention as part of the preferred resource "loading order" established through the Energy Action Plan process and confirmed in D.04-01-050 and D.04-12-048. D.04-10-035 outlined how these resources will affect load forecasts. The most important consideration for the purposes of this workshop process is the distinction between treatment of dispatchable and non-dispatchable types.

D.04-10-035 explicitly calls for different treatment of dispatchable programs and tariffs versus non-dispatchable tariffs and programs. Dispatchable demand side options will be considered as resources and counted as qualifying capacity. These resources are addressed in more detail in Section 5.B. of this report. Non-dispatchable DR and EE programs will be accounted for in the load forecasts.

Workshop participants discussed several issues concerning the effect of demand side resources on load forecasts remain unresolved. These include: (1) how to determine how to adjust each LSE's load forecast for the non-dispatchable tariffs and programs, and (2) development of the hourly impacts of such programs.

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

At the November 30 scoping workshop, SCE and PG&E presented alternative approaches for the allocation of energy efficiency and demand response impacts to LSEs. Generally speaking, PG&E proposed to allocate on the basis of funding, while SCE proposed to allocate in a pro-rata fashion according to LSE share of aggregate load.

A follow-up team developed a workplan to pursue competing approaches put forward by PG&E and SCE. The follow-up team released a written paper on January 14, 2005, analyzing the approaches of both companies. This report was discussed at the January 18 workshop and parties were comfortable with the broad direction of the proposal. The paper is attached to this report as a Working Proposal (Appendix C).

While the paper generally makes sense in light of the necessary quantification of EE and DR impacts, staff believes that there are some elements that should not be accepted or that require further thinking. These are:

- The report fails to address the issue that most DR programs that exist today and that will be quantified for summer 2006 are dispatchable, and thus are not debits from load but classified as resources. The illustrative computations of DR impacts on load adjustments are not of the appropriate scale and give a mistaken picture of the size of adjustments that will likely be made to load forecasts.
- While the body of the report does not dwell on this issue, the report (p. 1) does ask a rhetorical question about the desirability of focusing the impact assessment for EE programs on capacity. This approach wrongly interprets D.04-10-035. EE impacts are to be debited from load forecasts. There are strong hourly differential impacts of EE programs that should be assessed and taken into account in modifying not only the level, but the shape of LSE load forecasts.[15]

[15] For example, residential air conditioner efficiency programs mostly affect summer on-peak and not even summer off-peak loads, refrigerator efficiency programs reduce load in all hours of the year, and residential lighting programs almost entirely affect off-peak loads in all parts of the year.

- The report (p. 3 and pp. 7-8) is too conclusory that incremental EE impacts are what should be used to modify preliminary LSE load forecasts. Discussion of these issues at the January 13 and February 9 workshops raised the issue that the extent to which adjustments based on incremental versus total impacts depends upon the methodology used to prepare the preliminary load forecast. Some methods strongly tied to recent historic data might well have captured some EE program impacts and thus only incremental impacts should be removed through an external adjustment. Other methods may be so disconnected from tracking programmatic impacts on recent consumption data that total impacts of programs should be removed from preliminary load forecasts.

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

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

A focus on hourly loads is necessary to implement the interpretations of the obligation for LSE load shape, which in turn emphasizes the need to prepare programmatic impacts on an hourly basis. As noted earlier, this is especially important for DR and DG impacts that are designed to focus on peak hour loads as opposed to off-peak loads.

At the scoping workshop on November 30, 2004, PG&E and SCE proposed alternative ways to develop hourly load impacts. Both proposals represent somewhat crude approximations to the true hourly load impacts since existing measurement and evaluation (M&E) efforts have not been designed to prepare such impacts. The final Topic 3-4 Working Proposal correctly notes the need for improved M&E efforts (p. 6). Modification of existing M&E efforts for various program categories is a key linkage to resource adequacy needs that should be pursued in terms of the research design changes and funding required to accomplish these new studies in a timely manner.

PG&E proposed to develop hourly impacts by associating programs with end-use loads and using existing load shape research to create hourly shapes for impacts. SCE proposed to develop a number of standardized “day types” and to then expand from these day type impacts into hourly impacts for all days. It appears that the PG&E and SCE approaches emphasize the relative strengths of historic load research that the two companies have pursued.

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

The report also describes the problems associated with estimating rollout of programs as an indicator to the monthly impacts of programs (p. 8). This is now a more severe problem since it has been agreed that the preliminary load forecast filings each spring will address load forecasts for all twelve months of the year (June through December of 2006 in spring 2005 filings to the CEC).

The Commission should direct IOUs to make monthly estimates of EE, DR, and DG for all twelve months of the year despite any uncertainties of responsibility about program administration.

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

Discussion of these topics at the January 13th and 18th workshops surfaced the previously unrealized need for the three IOUs to prepare and document the hourly impacts of EE, DR and DG programs and to provide these impacts to the CEC for use in the adjustment of LSE load forecasts. These impact evaluation responsibilities must be completed and documented for handoff to the CEC each spring. In effect, IOUs have two parallel analytic activities underway: (1) one in common with other LSEs to prepare their own preliminary load forecast, and (2) a second one preparing monthly and hourly impacts for EE, DR and DG affecting all loads within their service area. To the extent that the CPUC assigns programmatic M&E activities for EE, DR or DG to entities other than IOUs, then these entities must also provide comparable impact products to the CEC on the schedule needed for review and adjustment of LSE load forecasts each spring. These informational needs that support resource adequacy requirements should be taken into account when selecting independent evaluators for EE, DR, and DG programs.

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

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

Of the three preferred resource types (EE, DR, and DG), DG is the least emphasized and in the current judgment of the parties at the November 30 workshop, its impacts are the least important. Unlike the thousands of megawatts of aggregate impacts from EE and DR programs, DG programs appear to have no more than a few hundred megawatts. The minimal scale of expected DG penetration by summer 2006 suggested lesser attention to the issue at this time, but this may change if DG receives greater funding and greater overall attention from policymakers.[16]

It was essentially agreed that each IOU would prepare DG penetration and stereotypical electrical production patterns that would allow development of hourly impacts. These will be provided to the CEC for use in adjusting preliminary LSE load forecasts on a pro-rata basis like that of EE and DR. This places DG impact evaluation on par methodologically with EE and DR impact evaluation as described in Section 4.C. of this report.

If DG programs, or DG in response to rate design changes, appear to become a more important factor affecting loads, then more sophisticated methods identifying impacts and attributing them to the specific customers of individual LSEs may become important.

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

[16] This judgment of the workshop participants does not encompass the “Million Solar Roofs” proposal now being prepared as redirection of existing renewables funding or a through new legislation with additional funding.

4.E. Total Losses Methodology

The planning paradigm that was the basis for the 15%-17% PRM adopted in D.04-01-050 defines peak demand to include customer loads, all losses, and other unaccounted for energy (UFE). In contrast, these same planning conventions exclude losses when reporting delivered energy. Delivered energy (also know as sales to ultimate consumers) is most commonly reported as energy transferred to customer premises as measured at the customer meter interface to the distribution system. In the planning paradigm for the year-ahead load forecasts, losses and unaccounted energy are excluded when reporting energy, but included when computing peak demand and contributions of hourly loads of end-users to the system load.

The settlement procedures adopted when the CAISO was created devised a method that assigns the distribution portion of losses to loads, but measures generation net of losses to the CAISO system boundary for each power plant individually using the generation meter multiplier (GMM) concept. As a consequence, the CAISO's operating and settlement practices do not have a existing means of identifying transmission losses on a long-term forward basis. At the November 30 scoping workshop, the CAISO and SCE agreed to attempt to pursue this topic.

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

UFE is the discrepancy commonly found between the sum of all customer meter measurements and energy injected into the system, after adjustments for transmission and distribution losses. Sources of UFE include customer meter measurement error (slow rotation on electro-mechanical meters), theft (bypasses of meters or meter counter-rotation between meter reading cycles), errors in estimates of distribution system losses, and other minor problems. Generally UFE is a positive value, meaning that it is one of the factors that one must explicitly add to customer meter load estimates, along with physical losses, to build up to total system energy use.

At the January 18, 2005, Load Forecasting workshop, the CAISO reported some preliminary information to the workshop facilitator about scale of losses and UFE. The CAISO data is reported in Table 3 below.

As a result of the relative constancy of the loss data reported by the CAISO, parties agreed that a simplified method would be recommended. The existing hourly distribution loss formulas would be used with an upward adjustment common in all hours of 3 percentage points. In effect, transmission and unaccounted for losses would be a constant percentage increase in each hour even though distribution losses vary on an hourly basis.

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

4.E.2. Distribution Loss Factors

The appropriate specialists in IOU distribution losses did not participate in the January 18th workshop; and except for the abbreviated discussion on distribution loss factors at the November 30th workshop none other was addressed by any other party.

In the absence of further information, advisory staff reviewed the IOU websites to identify useful information concerning this topic. The three following IOU websites provide some additional information about distribution loss factor formulas; however, in the judgment of staff they reveal unsettling news.

http://mads.pge.com/dlf/dlf_rsif.doc

http://www.sce.com/NR/rdonlyres/7059BCA2-0720-4BB0-ADC7-85E1D80F4021/0/ESPHandbookChapter17v3dot6.pdf

http://www.sdge.com/business/esp/electric/startup/EECC-TBS.pdf#page=2

Staff believes that the DLF website's supporting DA load scheduling and settlement are not compatible with developing long-term forecasts. These implementations of a DLF methodology are used for Day-Ahead schedules and settlements, not for planning. Thus the premise of the workshop discussion that existing DLF methodologies could be supplemented by transmission and distribution loss factors seems erroneous. This means that a workable proposal for total losses applicable to customer end-use loads has still not been developed.

IOUs should address the following questions in their comments on this workshop report:

- *Do DLF forecasting methodologies exist that could be available for use on a long-term forecast basis, e.g. in spring 2005 for hourly load forecasts through December 31, 2006?*
- *If these are not available, how could the existing DLF methodology be modified to allow its use on a long-term forecast basis?*
- *Given that DLFs are prepared separately for two or three voltage levels, for the purposes of year-ahead and month-ahead aggregate load forecasting, is it reasonable to assign various customer classes to specific of these voltage levels, e.g. industrial customer class loads use high level DLF formulas?*
- *Is it correct that DLFs exclude UFE? If not, can those IOU DLF methodologies, which include UFE, have that element removed easily?*

To the extent further development of DLFs is necessary, how can this be completed and reviewed in a manner appropriate to the needs of preparing long-term hourly load forecasts for 2006 in the summer of 2005?

Table 3
Transmission Losses and UFE

Total ISO Transmission and UFE Losses as a percent of Load reported by LSE (not including UFE or Transmission losses)

month	1	2	3	4	5	6	7	8	9	10	11	12	Annual
2002	4.27%	4.16%	3.90%	4.12%	3.70%	3.53%	2.95%	2.30%	3.10%	3.09%	2.70%	2.38%	3.36%
2003	2.91%	4.12%	2.93%	3.92%	2.67%	3.35%	2.88%	1.96%	1.70%	2.54%	2.81%	2.73%	2.80%
2004	2.77%	2.95%	3.28%	3.80%	3.33%	2.81%							3.16%
Average	3.32%	3.75%	3.37%	3.95%	3.23%	3.23%	2.92%	2.13%	2.40%	2.81%	2.75%	2.55%	3.11%

Total ISO Transmission Losses as a percent of Load reported by LSE (not including UFE or Transmission losses)

month	1	2	3	4	5	6	7	8	9	10	11	12	Annual
2002	2.54%	2.58%	2.43%	2.43%	2.54%	2.59%	2.38%	2.42%	2.42%	2.44%	2.60%	2.42%	2.48%
2003	2.60%	2.47%	2.46%	2.47%	2.65%	2.90%	2.60%	2.63%	2.72%	2.56%	2.77%	2.93%	2.65%
2004	2.84%	2.75%	2.66%	2.46%	2.60%	2.75%							2.68%
Average	2.66%	2.60%	2.52%	2.45%	2.60%	2.74%	2.49%	2.53%	2.57%	2.50%	2.69%	2.67%	2.60%

Total ISO UFE as a percent of Load reported by LSE (not including UFE or Transmission losses)

month	1	2	3	4	5	6	7	8	9	10	11	12	Annual
2002	1.73%	1.59%	1.47%	1.69%	1.16%	0.94%	0.57%	-0.12%	0.68%	0.65%	0.10%	-0.04%	0.86%
2003	0.31%	1.66%	0.47%	1.45%	0.02%	0.46%	0.28%	-0.67%	-1.02%	-0.02%	0.04%	-0.20%	0.22%
2004	-0.07%	0.20%	0.61%	1.34%	0.65%	0.06%							0.47%
Average	0.66%	1.15%	0.85%	1.49%	0.61%	0.49%	0.43%	-0.40%	-0.17%	0.31%	0.07%	-0.12%	0.52%

Corrected: 3/9/2005

Chapter 5. Resource Counting & Deliverability

Load is served by a variety of generation technologies, and LSEs have a variety of means to purchase the energy they need. In addition, mechanisms designed to reduce demand at peak times can contribute to adequacy of supply. The Resource Adequacy framework focuses particular attention upon the nature and location of generation resources and programs to reduce demand that will be used to meet maintain stability. The CAISO requires assurances that critical generating assets will be available to produce power and deliver it to the load that needs to be served.

This Chapter first evaluates two proposals for evaluating the overall nature of RAR commitment. It then comprehensively reviews how the generating technologies available to serve California, and the financial mechanisms for procuring power for end-use customers, could be used in meeting an LSE's resource adequacy requirement.

5.A. Monthly Peak Or Load Shape Paradigm

The CPUC held three days of workshops devoted to the question of the overall nature of the RAR commitment, a topic that was initially thought to be fully understood by staff and by all parties, but which, when examined more closely, resulted in serious disagreements among the parties. In March 2005, the CPUC issued a draft decision intended to clarify the obligation of the LSEs under RAR to extend to all hours. The reference to "all hours" was understood by some to nullify a previous understanding about counting resources for an entire month despite their clear lack of ability to serve during every hour of the month and about the lack of a need for every resource to be available and dedicated to service in every hour. Publication of the draft decision exposed and clarified the nature of the controversy. Ultimately, the draft was withdrawn before the scheduled vote, and the Assigned Commissioner ordered further workshops to explore and clarify the controversy and present appropriate alternatives for review.

The workshop meetings and the documents presented during those meetings identified the specific issues underlying the controversy and resulted in the development and clarification of two views of how RAR can be accomplished.

5.A.1. The Monthly Peak Method – "Top-Down"

The "Top-Down" method (TD) is based on calculating the peak demands for each month and counting the resources available to meet those needs. That is, the reserve requirement is based on the peak day load. The LSE would have to carry reserves for its peak load for the month plus 15% for the entire month. Peak demand is measured in terms of megawatts (MW), and resources are counted in terms of productive capacity, also denominated in MW. Each month's requirements can be envisioned as a comparison of two columns, one a measure of peak demand plus a planning reserve margin of 15%, and the other represented by a stack of resources. As long as the column of measured resources is taller than the column of demand, the RAR is satisfied for the entire month.

Implicit within that simple construct is a more complex set of relationships. For customers are not served only during the peak hour of each month, they consume energy in differing quantities every hour. Similarly, generators do not serve only by being present at the peak hour; they generate power according to their dispatch schedules throughout the month. While all generators are dedicated to system support whenever they are available, it is understood that not all resources are available in all hours. This property suggests the moniker, "top-down," for this method relies on a count of the resources available to serve the peak load of a month and implicitly recognizes that many of those resources are not available in all hours of the month. The resource stack, therefore, looks like a declining staircase, with the most limited resources stacked on top of other resources that are available to serve in any hour of the month. Scheduling and dispatch are not part of the TD RAR design.

5.A.1.1. Specifics of the "Top-Down" Proposal

The proponents of the TD proposal[17] provided several documents instead of a single one. Therefore, this presentation of the specifics of the TD proposal is an amalgamation of all of the submissions. *Parties are invited to comment on shortcomings of this write-up.*

[17] IEP, Mirant, Constellation

The TD proposal is intended to be a transitional mechanism that advances California toward a more durable resource adequacy framework. It begins the process of migrating from a market structure where capacity is procured through an energy framework (where capacity is bundled with energy) to an end state where capacity can be procured independently through a centralized capacity-based system. The proposal is based on LSE contribution to system peak covered by capacity resources and a local resource adequacy requirement allocated to LSEs based on their contribution to load in each load pocket. The precise determination of LSE load that is the basis for the resource obligation needs to be resolved.

The resource adequacy requirement should, it is argued, be met by a single product: available capacity. The October decision already set out rules for counting available capacity resources. The workshops have further developed methods for counting resources, as discussed in other parts of this report. Once qualified capacity for resources is determined, exceptions not currently fully covered can be evaluated.

Comments by IEP suggest an initial listing of exceptions:

- Energy-limited resources internal to the CAISO control area based on availability during the four to eight super-peak hours. This could be determined based on historical availability and capacity provided during those hours. The CAISO would not be able to call upon such resources beyond the hourly limits established except during emergencies.
- Environmentally limited fossil resources. Exceptions based on resource specific characteristics and historical period performance (adjusted if necessary for new regulatory constraints). Once again, there would be limits on the CAISO's ability to call on such resources.
- Pumped Storage Hydro resources. Evaluation would be resource specific and based on historical period performance, with specified maximum hours of commitment.
- Non-Pumped Storage Hydro resources. Evaluation would be resource specific.
- Qualifying Facilities. Resource specific evaluation.
- Intermittent Resources. Resource specific evaluation.

Comments by Mirant note that during the transition, the process must recognize that LSEs have entered into other forms of commitments. Therefore the following special exceptions are proposed for the transition period:

- Limited Availability Contracts with specific resources or portfolios of resources and standard delivery attributes (e.g., 6x16 firm energy contracts). Capacity from such units could not be resold by the owner. They would be compliant with RAR if scheduled according to the contract terms.
- Limited Availability Call contracts with specific resources or portfolios of resources and non-standard dispatch attributes (e.g., 6x16 options with 2-day-ahead call). Again, capacity from such units could not be resold by the owner. And the LSE must establish acceptable dispatch assessment with the CAISO and schedule accordingly
- Firm Liquidated Damages Contracts for delivery within California (e.g., CAISO Firm). These contracts are not tied to physical resources but require the seller to deliver a specified amount of energy to a particular point under the terms of the contract. (Liquidated Damages contracts are discussed separately in Section 5.D. of this workshop report.) The proposal suggests the Commission (a) Require LSEs to provide a schedule of LD-committed contract capacity by month based on existing contract expiration as part of their RAR demonstration; (b) Review this information with the CAISO and/or CEC to identify the potential magnitude of double-counting and surplus resources available to reliably serve this open position; and (c) Establish position limits if needed and a transition period to phase out reliance on grandfathered LD contracts based on review.

Mirant advocates development of a maximum cumulative contribution of specified resource categories with physical and contractual availability limitations. This would alleviate over reliance on resources that could not be counted on to serve a large portion of a month outside of the peak period.

The year-ahead showing would be a comparison of an LSE’s coincidence adjusted contribution to system peak, including a 15% PRM, to that LSE’s stack of resources meeting the requirements to be considered RAR resources for each of the five summer months. The LSE would demonstrate that the resources contracted year-ahead fulfill at least 90% of the requirement. The monthly requirement for the summer months would be for the LSE to demonstrate that it had closed the gap and met 100% of its resource requirements, including the PRM. For the non-summer months, the LSE would demonstrate that it has resources capable of meeting its contribution to system peak, including a 15% PRM. IEP adds that there would be no need in the LSE compliance showing to acquire additional resources to "make up" for those resources that are not available at all hours due to allowable constraints.

For a resource to be qualified to count for meeting the RAR, it must be required to offer to the CAISO, just as it does today, unless it is already scheduled. Resources that are not counted for RAR would not have such an obligation.

5.A.2. The Load Duration Method – "Bottom-Up"

The "Bottom-Up" method (BU) is based on calculating each LSE's load duration curve to determine hourly needs, not just for the peak hour, but for all hours during the month. Then a 15% PRM is added to the entire function, hour by hour. Each hourly total is measured in terms of MW. The BU method is similar to the TD method, with the addition of a time element representing the hours in a month. In other words, the TD approach set the obligation based on the peak load plus reserves for the month where as the BU approach requires a calculation of the load plus reserves for every hour of the month. Resources are counted in terms of their productive capacity, MW, and also in terms of the number of hours they are expected to serve, with the result that the resource stack can be seen as energy, megawatt-hours (MWh). Each month's requirement can be seen as a comparison of two lines – the downward sloping load duration curve including PRM, and the hourly resource stack, which resembles a declining staircase, with the resources that will serve the fewest hours stacked on top, and the resources that will serve for more hours underneath. As long as the line representing the resource stack is greater than the line representing the load duration curve plus PRM in every hour of the month, the RAR is satisfied for that month.

5.A.2.1. Specifics of the Joint Parties "Bottom-Up" Proposal

The Joint Parties[18] prepared the BU proposal as a transition mechanism that is to be in place only until such time as the State adopts a more durable resource adequacy framework. It addresses the "all hours" requirement first raised in the Assigned Commissioner Ruling of February 8, 2005. The JPs do not believe that it is necessary to maintain resources necessary to serve the monthly peak load at all hours during a month. Nevertheless, the JPs support a 115% planning reserve margin for each hour.

The BU proposal begins with development of a Resource Duration Curve for each LSE based on monthly peak-load forecasts including a coincident peak adjustment, as discussed in workshops. LSEs will use historical load shapes to create a monthly load duration curve. Except for the adjustment to the peak, there is no adjustment to the remainder of the energy in the monthly load duration curve. Then a PRM of 15% is added to each hour, resulting in a Resource Duration Curve.

Each LSE will be responsible to demonstrate that it has resources sufficient to cover its Resource Duration Curve, i.e., that in each hour its resources are planned to be at least 15% above its expected load. In its year-ahead showing, each LSE would demonstrate that it has met 90% of the resource needs of its Resource Duration Curves for the five summer months. For the month-ahead showing for a summer month, each LSE must demonstrate that it has met the remaining 10% of its resource needs for all the hours for that month. For the month-ahead showing for a non-summer month, it must demonstrate that it has resources sufficient to cover its entire Resource Duration Curve for that month.

JPs propose that Resource Eligibility Factors (REFs) be used to compare LSE's resource portfolio to the resource duration curve. REF is proposed as a measure of the percent of time resources can be counted against an LSE's RAR. In nearly all cases, the REF of any given resource can be determined on the basis of resource characteristics, contract terms, or historical performance. In effect, RDFs would become another counting rule not unlike the counting rules

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[18] The Joint Parties are Southern California Edison, Pacific Gas & Electric, CLECA, CMTA, AReM, ORA and TURN.

adopted by the Commission in the October decision and those developed in the Phase 2 workshops.

Non-energy-limited resources would have a 100% REF, that is, would count towards an LSE's monthly RAR 100% of the time, if the resource does not have a planned outage (summer months) or does not have a planned outage that cannot be rescheduled by the CAISO (non-summer months). Resources such as nuclear, coal, gas (not emissions limited), 7x24 contracts, QFs, run-of-river hydro, and some imports, could be considered likely to meet the 100% REF criteria.

JPs propose that some energy-limited resources could meet the 100% REF requirement under some conditions if they could meet the planned-outage rules described in the previous paragraph and the resource has a monthly capacity factor of at least 15% (i.e., it has sufficient energy to run at full load for at least four hours every day of the month), it can operate at full load on any given hour of the month, and it is able to provide ancillary services during all hours when it is not otherwise generating energy (i.e., non-spin, with or without the contingency flag set). To the extent that some energy-limited resources have annual energy limitations, the LSE will be responsible for determining which months and hours such resources will be counted. Resources that typically meet these conditions are those with period energy limitations (e.g., monthly) due to either fuel limitations, such as storage hydro or a cap on emissions.

Other energy-limited resources would not qualify for 100% REF. Those resources have use limitations (e.g., 10 starts per month, or specified hours of delivery) or run limitations (e.g., cannot operate more than 100 hours per summer period) and/or may be fuel or emissions limited such that they cannot provide ancillary service. Such resources would have an REF equal to the monthly capacity factor of the resource as determined by the most appropriate of three methods: (1) Historical performance (appropriate for non-ancillary-service storage hydro, pumped storage hydro, demand response programs), (2) Contract terms (appropriate for 6x16 contracts, capacity exchange agreements), or (3) Regulatory constraints (such as emissions limitations).

The Resource Duration Curve and the Resource Eligibility Factors combine to create a showing that covers all hours of the month:

- Qualifying resources are "stacked" in a Resource Table against the peak-load requirement (as discussed in Phase II workshops). The Resource Table is sorted from highest to lowest REF (i.e., 100% REF resources are first in stack).

- The resource duration is determined for each point in the Resource Table (as measured off the RDC). If necessary, large resources can be represented in smaller MW blocks to avoid miss-counting the appropriate resource duration.
- The all-hours RAR is a resource requirement, not an energy requirement. However, the showing should also demonstrate overall energy sufficiency by comparing the total energy producing capability or all resources (measured at their maximum potential capacity factors) to the LSE's total monthly energy forecast.
- Depending on the characteristics of an LSE's resource portfolio, showings can contain a single RDC and Resource Table for all hours of the month, or can be represented as separate on-peak and off-peak RDC and Resource Tables.

5.A.3. Staff Discussion Of Differences Between The Two Methods

Over three days of workshops the features and advantages and disadvantages of both BU and TD proposals were examined and debated. In addition, participants prepared responses to a series of specific questions about the relative virtues of the two paradigms. The following are discussion items posed by Staff, which draws upon the responses, but does not intend to repeat all of the information presented by parties. Each question is listed, followed by a general answer reflecting the responses of participants.

5.A.3.1. What Are The Differences in Total Costs To Specific LSEs And To All Californians?

Advocates of the TD approach maintain that since a capacity-based construct is not currently in place to attract investment and maintain existing units, and because the CAISO has a free call on units through the FERC's must-offer obligation, costs may rise under either TD or BU compared to what they are currently.[19] That is, the real costs of capacity are not currently

[19] As noted in the Commission July 2004 reliability order, LSEs can schedule infeasible and undeliverable energy contracts in the CAISO and the CAISO must incur congestion, must-offer, and redispatch costs to serve load. The CAISO-related costs of serving load are not reflected in the LSE procurement costs, which may disguise the true costs of relying on non-physical energy contracts.

reflected or recovered in existing energy-only capped markets.[20] Since the current construct may not ensure adequate fixed cost recovery of new or existing units, whichever means is used to compensate suppliers for their costs will be an increase over the compensation available today. It is appropriate that costs be appropriately allocated to LSEs, who will bear them on behalf of their customers following a cost causation principle. For steam units, there may be no cost difference between providing capacity services all hours of the month versus providing a lesser duration service because capacity is greater than demand in off-peak hours, and the market value of off-peak capacity may be low or zero. In addition, it is uneconomic for some units to ramp up and down each day and it therefore makes sense to be available all hours. An important point is that if the capacity-based obligation is intended to provide for the carrying costs of units required to meet peak demand, those carrying costs, or fixed costs, must be recovered whether the unit is available all the time or a few hours per year. If there is a substantial difference on the TD and BU approach, it is because there is a differential in the provision of fixed costs being paid to suppliers providing capacity.

The CAISO states that the workshops were helpful in reducing arguments about the cost differences between BU and TD. Still, according to the CAISO, there are two cost issues that should be addressed:

1. Costs associated with additional procurement solely to satisfy the RAR. The CAISO indicates that the cost is not entirely clear for either approach, and cannot say for sure which approach would be more costly.
2. Unit price, or MW price, of an eligible capacity product. The CAISO believes that the value of capacity in off-peak times is minimal. This leads to a conclusion that there is little opportunity cost from a seller's prospective of moving to a 24x7 obligation because the seller is unlikely to recover significant capacity value in the off-peak periods. Therefore any cost benefit in favor of the BU approach is unlikely to be meaningful. The CAISO believes that forward commitments for off-peak sales can be of tremendous value for both the LSE and the supplier to compensate for

[20] This overstates the case since existing bilateral capacity and energy contracts contribute to fixed cost recovery.

unrecovered capacity value. Further, the CAISO believes that the MRTU design can accommodate LSEs' forward off-peak arrangements.

JPs argue that if the ability of LSEs or of existing California generating resources to engage in exchanges or off-system sales is undermined through the imposition of a must-offer requirement that extends to all hours, then the imposition of the TD mechanism will result in a substantial revenue loss and possibly a substantial increase in costs to meet needs that otherwise would have been met through exchanges. For instance, they assert that it is not likely that non-firm transactions developed after the close of the DA market would be satisfactory to the Northwest entities to whom they trade off-peak sales. So this problem needs to be worked out. If it is worked out, there should not be much substantial difference between BU and TD in overall costs. JPs state that the BU proposal allows costs to Californians to be minimized through maximum resource utilization.

At the workshop meeting of April 29, there was much discussion of the differences in costs between the two methods. For the most part, the costs appear to be the same. One area of potential difference is that the TD method may not be consistent with exchange agreements outside the CAISO control area, that is, inter-control-area transfers of power that are scheduled ahead by contract. California entities have substantial exchanges with entities in the Northwest. If such transactions cannot be accommodated in a way that is substantially firm and satisfactory to trading partners in the Northwest under the TD method, then such exchanges would either become less firm much more expensive, or they might not be able to happen at all, resulting in much higher costs for Californians (and for residents of the Northwest as well). If the off-system sales commitment issue is not a problem for TD implementation, there should be no substantial difference in total costs between TD and BU, it was agreed in discussion.

5.A.3.2. What Are The Differences In Ease Of Implementation?

Advocates for TD argue that TD requires only minimal additional efforts beyond what has been completed to date in RAR workshops and CPUC decisions. The TD approach has been implemented in other markets; experience and expertise are available. It is a proven method. Costs of eventual implementation of a formal capacity market based on existing designs will be lower if the TD approach is adopted because of the consistency in approaches. Advocates for TD also argue that implementation of BU would be difficult because it has never been tried before. It is a new idea that will require substantial “need to reinvent the wheel.” Furthermore, since the TD approach sets the RA obligation based on a single calculation of the months’ peak, as opposed to forecasts for load for every hours of the month, the implementation would be easier and the opportunity for miscalculation diminished.

The CAISO argues that the BU approach has the edge, though slightly, for the determination of which resources are available, and when they are available, will be a mere matter of reporting, rather than requiring any workout of arrangements and schedules.

JPs argue that the BU approach is similar to the procurement that LSEs do now, and using it would allow implementation on the current time track. Since the TD method is not yet fully developed, it is unclear how implementation would be accomplished on current schedule. If a separate capacity product must be developed now in order to implement TD, it may be rushed and may not be easily implemented.

Staff notes that it is not a matter before the Commission at this time to establish a capacity market or a capacity product. Discussion of capacity trading and tagging, as well as multi-year commitment to capacity resources, was put off to the next generation of RAR issues.

5.A.3.3. What Are The Differences In The CAISO’s Operational Needs?

Advocates of TD argue that TD meets CAISO needs since the availability requirement is similar to the current Must Offer Obligation (MOO). The CAISO will continue to be able to meet operational needs as it does now relying on RAR resources. The TD approach will encourage a uniform offering obligation while accommodating energy-limited resources to insure CAISO system stability. Advocates of TD argue that the BU approach may not meet CAISO needs and may be more difficult for the CAISO.

The CAISO states that the TD method is more consistent with its operations, with resources offered for all hours they are physically capable of running consistent with environmental or other regulatory limitations. Under the BU approach, resources are limited not only by their physical capabilities, but also by contract, creating a possible impact on the CAISO’s ability to optimize resources. However, the TD approach may also be subject to this inefficiency if existing contractual arrangements are deemed eligible to satisfy the RA obligation during a transition period.

The JPs argue that the BU method, by working from the load duration curve, ensures an adequate supply of resources in all hours to meet load plus reserves. It ensures an appropriate resource mix, and it reveals planned outages in all hours, not just at peak. By contrast, JPs argue it is unclear how RA is impacted by use limitations in off-peak hours.

The CAISO also argues that the BU approach may limit the CAISO's ability to respond effectively to energy deficiencies, for such deficiencies can occur in any hour, and the BU method does not require resources to be available outside of their contracts.

Discussion at the workshops included this topic, and it was generally agreed, though not universally agreed, that the CAISO could operate under either BU or TD with some accommodation for limited-use resources. There are already such accommodations in existence at this time. CAISO comments indicate a preference for the TD mechanism because it results in unit commitment in all hours when capacity is available, which is comparable to today's must-offer requirement.

5.A.3.4. What Are The Differences In Measuring Compliance?

Advocates of TD argue that compliance is much simpler under a TD framework, with two simple compliance features. LSEs must first demonstrate that they have secured the required resources, and the CAISO verifies that resources comply with the availability obligations and coordinated maintenance requirements in accordance with terms and conditions approved by the Commission. Advocates of TD argue that BU will be difficult to verify compliance with a complex system that involves analyzing load shapes and comparing to resource availability. Mirant states that transparency is a key element in measuring compliance, and the TD method is simpler and clearer in it measurement. It is difficult to measure how a requirement is being met without being able to clearly see how all of the resources in the market fit together. This is why capacity markets in general rely on a single capacity product. The top-down approach, with a single, clearly-defined capacity requirement facilitates transparency.

JPs state that under BU, compliance is measured inherently in the process of implementing RA throughout each period. TD compliance would be measured by peak-load resources against the peak hour, and demonstration of exceptions may be unclear and difficult to monitor.

The CAISO states that any compliance feature cannot, and should not, place the CAISO in the position of having to interpret bilateral contracts or accommodate myriad operating and contractual limitations.

Discussion at workshops turned on the degree to which the BU method is more difficult to measure compliance. The JPs tended to minimize the degree to which taking account of load shape would be costly to compliance, and noted that compliance would, to some degree, be known hour by hour, for the BU program requires resources sufficient to meet load in each hour. Advocates of TD argued that compliance measurement would be more difficult in a BU method and that compliance in the TD filings would be simple to evaluate.

5.A.3.5. What Are The Differences In Consistency With Existing CPUC Procurement Policies?

The extreme complexities of the procurement process for IOUs makes it difficult to state definitely how either approach does or does not match existing policies. For example, from the perspective of encouraging investment in new resources, advocates of TD argue that regulatory stability is the foundation for investment, and that the Commission has indicated that it is interested in a capacity-based system in the future. The TD mechanism is a step in that direction. However, the time horizon of RA for only one year forward may not really provide much investment impetus. On the other hand, JPs state that the BU method reflects traditional resource planning and procurement as performed in the West now. IOUs know that they should be selecting a portfolio of resources that satisfy total needs. BU prohibits excessive reliance on use-limited resources.

Another feature of the Commission's existing procurement policy is to encourage the IOUs to acquire resources using the "loading order" initiated through the Energy Action Plan process, and now embodied in D.04-12-068. Renewable and demand response resources are strongly encouraged and numeric goals have been established, either by legislation or by Commission policy. On the other hand, intermittent resources (like wind) and demand response pose a different problem for meeting resource adequacy. However, through proper resource planning techniques, these resources can find proper use within resource adequacy requirements and still meet the CPUC's loading order requirements.

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

Advocates of TD argue that the TD approach ensures that appropriate forward capacity demand signals are registered in the marketplace as soon as possible, resulting in price signals that will establish the true value of capacity in California. It will align procurement responsibility with CPUC oversight and transparency by insuring that resources that are needed to meet locational and system conditions are met through long-term bilateral contracts. Adoption of TD will move LSEs towards adopting capacity products and away from mixed products where the capacity value is implicit within the energy value, but is not recognized or known. This is helpful in moving towards a capacity-based product in the future.

JPs note that both the TD and the BU methods are expected to be transitional mechanisms to bridge from the present to a future end-state design.

The CAISO supports the creation of some form of capacity market, the details of which remain the subject for future evaluation. The TD approach provides an advantage as a transitional mechanism. It is also more amenable to integration of a single standard capacity product. By contrast, the BU approach is inherently hostile to a uniform product because it follows an LSE's load duration curve to create differentiated capacity products.

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

5.B. Dispatch Authority For Demand Response Programs

D.04-10-035 clearly determined that demand response program impacts were to be included within resource adequacy. The order found that dispatchable programs would be classified as resources eligible to count toward RAR. Non-dispatchable tariff and/or program impacts are to be included within load forecasts.[21]

The January 13, 2005 workshop raised the issue of how the actual triggering mechanisms for dispatchable DR programs will be revised to allow them to be used within a resource adequacy context. Currently, some DR programs are only used under declared CAISO emergencies. That these resources are only to be used in declared emergencies may be inconsistent with the CPUC counting of some DR resources for RA so that they can be used to *avoid* emergencies and load interruptions. Another issue is that certain DR resources do not currently have to bid or be scheduled in the day-ahead timeframe as they are only required to be available under emergency provisions. Lack of availability day-ahead is inconsistent with the concept of must-offer requirements that are supposedly applicable to all RA resources. Workshop participants agreed that we will not know until implementation whether certain DR programs meet the CAISO operational requirements. If the DR programs do not support CAISO operational requirements, then some of the provisions, particularly with regard to day-ahead bidding, may need to be changed. The CAISO agreed to inform the CPUC if changes are required.

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

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

Subject to the limits established in D.04-10-035, dispatchable DR programs may be used by LSEs to satisfy forward commitment obligations. LSEs decide when they want to include DR program capabilities along with various other resources to satisfy their forward commitment

[21] Section 4.C. of this workshop report addresses various issues for those non-dispatchable demand response programs to be included as adjustments to preliminary LSE load forecasts.

obligations. For sake of illustration, SCE's Domestic Automatic Powershift Program (an air conditioner cycling program) will be used as an example. The issues raised are generic to most, if not all, dispatchable DR programs.

For example, SCE may choose to use its existing Air Conditioning (A/C) cycling capability of approximately 300 MW to show that it satisfies forward commitment obligations in August 2006.[22] To the extent SCE is authorized to expand this program to achieve more than 300 MW, SCE can count on more than 300 MW when it supplies appropriate documentation for the increase in program capability.

The issue is the number of instances in which SCE is allowed to count this program as part of the demonstration that it has sufficient forward commitments to satisfy its obligations. In the case of this program, SCE is limited to 15 calls per season. With 15 call opportunities, SCE could reasonably be expected to cover a string of high load days during an entire month. Given temperature fluctuations and the usual pattern of high temperature events, one might assume that SCE's 15-call constraint can cover both August and September. However, if spread out over the four summer months when the program is operable, that might mean four days for July, August and September with three days left over for June.

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

- *Is a call capability limited to at most 4 days per summer month enough to say that this resource can be counted as qualifying capacity for each of the four months?*
- *If four days per month is too few, then what is the minimum number of days that allows this DR program to be considered sufficiently flexible to serve as a reserve?*
- *Should DR programs with triggering conditions requiring CAISO emergency conditions be excluded as ineligible to be considered resource adequate, e.g. are there some dispatchible DR programs that should not be counted upon as a resource for resource adequacy, but held in reserve for true emergencies?If so, what level of capacity should be held back?*

[22] SCE would not be able to count this program in May 2007 and subsequent May's because the program is only authorized to operate during the June through September period of each year.

- *What mechanism should be used to decide which programs should be retained for true emergencies and which ones should be modified for more regular use in a resource adequacy framework?*
- *For those programs for which it is acceptable to convert to use in resource adequacy, should the triggering conditions of these programs be modified to allow DR to be scheduled through the CAISO on a Day Ahead basis?*
- *Should DR programs be exempted from the Day Ahead scheduling requirement, but be made available to the CAISO in some other way if system conditions warrant their use?*

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

D.04-10-035, Section 3.8, requires that resources nominated for resource adequacy be made available to the CAISO to maintain grid reliability. As background, the CPUC and the CAISO are developing a resource adequacy-based replacement for the "must offer" requirements that have existed since the FERC order of June 2001. As noted in the previous subsection, if a resource is not scheduled, and has submitted a bid, and if the bid is not accepted, then the resource's obligation is to bid into the CAISO residual unit commitment (RUC) process.[23] Parties have addressed the need for special treatment of energy-limited resources, usually meaning generating facilities like pondage hydro.

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

Clearly there are some parallels to the unit commitment process between slow start generators and some DR programs. If slow start generators are not committed many hours in advance of dispatch, then they will not be ready for dispatch. Similarly, a critical peak pricing

[23] The residual unit commitment (RUC) process is used for those slow start generators that cannot be dispatched on short notice, and must be committed to with a longer lead time than normal dispatch instructions allow simply to enable them to be ready for use. A demand response program with a Day-Ahead notification requirement, like Critical Peak Pricing (CPP) tariff, has some parallels. Like the generator called upon to start up through RUC there are consequences even if the demand response resource is not actually needed and the option is not exercised. In the case of CPP, a call of a CPP event that is later canceled will "use up" one of the limited number of "calls" to which the IOU is entitled for the summer season.

tariff is designed to send a "day ahead" notice to participating customers notifying them of the especially high prices that are being triggered for the next day. Failure to send this signal means that the tariff cannot be invoked.

On the other hand, slow-start generators obtain some payments from the CAISO for their startup costs whether they are ever dispatched or not. This is intended to repay them for actual variable costs incurred by startup activities. Of greater significance are the rules about dispatch of DR programs and tariffs. Unlike the requirements for generators of the CAISO tariff as ratified through FERC orders, there are a variety of CPUC-authorized program triggering conditions that must be satisfied in order for a program to be called. As explained above, the SCE air conditioning (A/C) cycling program can only be called for three specific conditions.

The Commission needs to resolve the following questions:

- *What are the system conditions under which the CAISO is allowed to exercise its "system support rights" for DR nominated as resource adequacy resources by LSEs? Alternatively, are there supply/demand conditions for the IOU service areas that are the appropriate basis for triggering demand response programs designed for that service area alone?*
- *Are these conditions the same as those for more flexible generation or energy limited generation?*
- *If they are not the same, are they more restrictive, essentially creating some sort of queue for resources in which DR resources come last?*
- *If there is some sort of queuing, is there a hierarchy among the various dispatchable DR programs?*

5.B.3. Implementation Of Demand Response Program Changes

Assuming that the questions asked above can be resolved on a broad policy basis, what means exists in R.04-04-003 itself, or to provide direction for activities in some other docket, to revise the tariff language now controlling the triggering conditions for all of the individual IOU DR programs for each of the three IOUs? Clearly, LSEs will need to know that these programs can be counted as resources in time to include them in their compliance filings now scheduled for September 30, 2005 (or 90 days after the issuance of the Phase II decision)?

The Commission needs to resolve the following:

- *To what extent must parties to R.02-06-001 and the participants in existing demand response programs be apprised of possible changes in individual program/tariff triggering conditions and allowed to comment?*
- *Assuming parties provide sufficient input on the policy questions raised in the previous subsections through comments on this workshop report, is an Assigned Commissioner Ruling (ACR) preceding the final Phase 2 resource adequacy decision an acceptable means to encourage the IOUs to propose advice letters implementing a solution to these demand response issues?*

5.C. Deliverability

Commission decision D.04-10-035 adopted the CAISO's baseline analysis to determine deliverability of resources that want to qualify as a capacity resource to meet the LSE's RAR.[24] Pursuant to the order, the CAISO is undertaking the deliverability analysis as part of phase 2 and redistributed the proposed baseline analysis, its data requirements, and a schedule for the analysis on November 14, 2004 (see Appendix D for CAISO study methodology and schedule).

The main issue to be resolved in the Phase 2 workshops is the allocation of import capacity to LSEs for purposes of using imports to meet the RAR. On December 3, 2004, the CAISO provided parties with an initial proposal to assess import deliverability. This document was the starting point for discussion at the December 7, 2004 workshop on import deliverability. Parties raised questions and provided suggestions to improve the initial proposal. Many of these issues were aired and resolved in the February 2, 2005 workshop.

The workshops were concluded before the CAISO published its preliminary deliverability baseline analysis report on May 3, 2005 and conducted its stakeholder meeting on

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[24] This initial analysis is for purposes of a starting point in determining which resources can count towards an LSE's RAR. Resources that are deemed deliverability will remain deliverable so that going forward, deliverability review will only be conducted on new interconnecting resources. In the longer-term the purpose of the deliverability analysis is not only for purposes of determining whether an LSE is meeting its RAR with deliverable resources, but also for transmission cost allocation purposes in new interconnections. FERC's Order 2003 provides for generators that want to serve as a capacity resource to pay for the necessary network upgrades to ensure their resource is deliverable under peak conditions. See 104 FERC 61,103

May 9, 2005. While the workshops focused on issues surrounding allocation of import capacity for RAR counting, there was little discussion about deliverability issues stemming from generation pockets, which exist due to limited transfer capability out of an area with a concentration of generation. The preliminary baseline analysis found that historical imports were deliverable.[25] However, the study found that approximately 2300 MW of generation within generation pockets to be undeliverable, but which can be mitigated with transmission upgrades.

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

In determining the import capability to be allocated among LSEs, the CAISO proposes to take a 4-day "snapshot", based on historic import schedules, using the highest import levels in 2003 and 2004.[26] The sample hours were selected by choosing hours with highest total import levels when peak load was at least 90% of the annual system peak load.[27] Parties raised questions regarding how often the CAISO would update the import figures and whether the import levels would be adjusted to reflect abnormal operating circumstances that could have occurred in the hours selected for analysis. The CAISO responded that the assessment would be annual and timed to coincide with annual transmission grid planning. This approach will provide predictability to the process and also serve to complement goals of longer-term contracting since historical assessments will incorporate historic contract obligations. The historic data would be adjusted to reflect unusual operating circumstances as well as to reflect newly created incremental capability from transmission upgrades. The CAISO proposed the following with regard to adjusting the baseline analysis:

[25] The deliverability test is only applicable to physical resources in the LSE portfolios. That is, a deliverability analysis cannot be conducted on contracts that do not specify where the contract is being sourced. The inability of non-resource specific contracts, such as some CERS contracts and liquidated damages contracts, to meet deliverability requirements is one of the primary arguments for disallowing or phasing out such contracts for purposes of counting towards the RAR.

[26] D.04-10-035 determined that historical import capability should be the basis for the analysis. See D.04-10-035, section 3.6.1 and the June 15, 2004 Workshop Report on Resource Adequacy, page 39.

[27] Scheduled Firm Transmission Rights, scheduled Existing transmission contracts and scheduled spot market usage were summed to determine the scheduled net interchange for each branch group. Unused existing transmission contracts would also be modeled as if they were used and considered in the baseline assessment.

- Initial import level data on each branch group should be representative of scheduled flows during summer peak conditions. A party could propose an adjustment to the CAISO's analysis of import levels prior to finalizing the baseline study by providing a detailed alternative analysis (e.g. using OASIS data) that focuses on a particular branch group. The CAISO would consider modifications based on the alternative analysis.
- The incremental increase in transmission capability of a branch group that is created by a planned transmission project- as demonstrated by a WECC- approved incremental increase in the path rating, subject to simultaneous flow limitations- should be added to the historical schedule data.

In the workshop parties requested the CAISO to detail the specific process for proposing a reevaluation of the import level determination. *We ask the CAISO to outline the specific process in its comments to this report.*

Once it was recognized that the Commission in the October order adopted a historical usage approach towards determining the import capability, no party took issue with the CAISO's proposed approach for conducting the import capability analysis or its process for updating the determination annually in the transmission grid planning process.

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

Once the CAISO determines the level of imports that can count toward the RAR, the question arises as to how to allocate the ability to import among the LSEs. There are three proposed alternative approaches.

1. PG&E and SDG&E support an allocation of inter-tie capacity in proportion to an LSE's contribution to the CAISO's transmission access charge (TAC). The TAC represents the transmission revenue requirements paid by each LSE. Parties favoring this approach support bilateral trading of unused inter-tie capacity among LSEs.[28]

[28] The selling or trading of import allocation rights does not infer rights to the transmission system. Rather, it means that an LSE has a particular allocation of the import capacity that it can count towards

2. Edison supports an allocation based on the TAC as well, but wants existing resource commitments to be grandfathered. Bilateral trading or selling of an LSE's capacity share would not be required.
3. FPL and SCE submitted an alternative proposal that each LSE's allocation of import capability be determined by its share of CAISO system peak load (e.g. if a LSE has 40% of the load at system peak, it would receive 40% of the allocation). The LSE would assign their total intended RAR use to specific import paths and provide that information to the CAISO. The CAISO would then determine if the LSE's shares are feasible. If the CAISO determines that the allocation on a particular path is not feasible to meet a local requirement, then it allocates first based on 'evergreen' priority, and then based on the load share percentage. An LSE can trade and sell its load share provision on a path in advance of the determination for feasibility, but reselling or re-trading would not be allowed.

There was not consensus among parties regarding the basis for allocating import capability for counting RAR. Options 1 and 2 were discussed at length in the workshops. Option 3 emerged later and did not receive workshop discussion. Therefore, while the issues surrounding of the first two options are discussed below, *parties are encouraged to include a discussion of the option 3 in their report comments.*

5.C.2.1. Allocation Of Import Capability Based On The Share Of Contribution To Transmission Access Charge

Most parties support an approach of allocating an LSE's share of import capacity based on TAC. FPL opposes allocating the capability on each inter-tie based on TAC contribution. Rather, it recommends that the aggregate "allocatable import MW" level be allocated based on

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the RAR. Trading and selling would enable an LSE using fewer imports to the meet the RAR to sell their share to a LSE that may not have a sufficient import allocation to count all the capacity it would like towards the RAR. Trading of rights may be desirable in instances where a particular LSE does not require its allocation on all the control area branch groups, but requires a larger share on a particular inter-tie. For example, a LSE with load in the North may want to trade its allocation on the Southern inter-ties in exchange for allocations on the Northern inter-ties.

TAC percentages and that the LSE could apply their shares on whichever inter-tie makes commercial sense. In the instance where a particular inter-tie is oversubscribed the share of the inter-tie would be allocated based on TAC contributions. ESPs pay the TAC and would be allocated import capability accordingly.

For ESPs, the TAC is incorporated within a generic transmission charge. Therefore, ESPs propose to submit the transmission payments to the CAISO for determination of the ESP's share of the import allocation based on the payments. ESPs suggested that the allocation be based on load served as opposed to contribution to TAC since the TAC charge for ESPs is subsumed within a broader transmission charge. Parties agreed that kilowatt hours of energy is a better known figure, but that figure is different than the capacity calculation, which may introduce inconsistencies since capacity as opposed to energy as the basis for the CAISO import capability determination. It seems that the alternative FPL/SCE approach of allocation based on share of peak loads may resolve some of the difficulties in the TAC allocation approach as they pertain to ESPs.

5.C.2.2. Evergreen Priority For Existing Commitments

The disagreement centers upon whether existing resource commitments will be grandfathered in such a way as to would allow LSEs that are more highly dependent on imports to meet the RAR with a larger share of import capability than the TAC percentage would afford. Edison argues that existing external resource commitments should receive an "evergreen" provision for purposes of counting toward the RAR, especially since these commitments were made prior to the establishment of RAR.

PG&E and SDG&E oppose this provision arguing that the evergreen proposal lacks specificity regarding the implications of this approach (e.g. MWs, duration of existing commitments, inter-tie points) and how it would effect the allocations of LSEs that have few or no existing commitments for external resources. Opponents of the evergreen provision maintain that this approach would result in one LSE receiving a disproportionate share of countable qualifying capacity, potentially at the expense of LSEs that rely on resources within the control area that require less use of the transmission infrastructure. SDG&E believes it is inequitable to give preference for existing commitments when the costs of the transmission grid are socialized through the TAC rates.[29] PG&E concedes that appropriate consideration may need to be given for commitments made prior to the development of the RAR, but that those provisions should not be granted without full knowledge about what those commitments are and the potential implications. Indeed, if the existing commitments are less than or equal to the anticipated TAC allocation then the problem is moot. Edison in the workshop agreed to list its existing commitments and how they measure up with its anticipated import allocation so that parties can understand the magnitude of the issue. *The Commission will be able to make a more informed determination on this issue if Edison provides that information in its workshop report comments.*

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

If an evergreen provision is granted for existing resource commitments, treatment of DWR contracts and how to account for the deliverable portion of the contracts will have to be addressed. Edison proposes that DWR contracts be considered firm resource commitments eligible for evergreen treatment. Edison maintains that counting deliverable DWR contracts as firm will ensure that ratepayers will not have to pay for capacity to replace portions of the DWR contracts, which cannot be counted due to insufficient import capability. For contracts with sellers' choice provisions, meaning that the seller can choose to deliver at the inter-tie or within the control area, SCE proposes that the contract's historical delivery be used to assess the path on which the contract will most likely be delivered.

PG&E points out that only deliverable resources can count towards RA and that an allocation of import capability should not be adjusted for these existing resources. *In the comments on the workshop report, parties should address how the deliverable portion of the contracts can or will be determined.*

[29] The TAC rates socialize high voltage transmission charges in a manner that all loads pay the same rate regardless of the level of grid use. SDG&E maintains that it is unfair that LSEs that use the transmission infrastructure less by relying on resources closer to load centers have to first pay the socialized rate and then provide the entities relying on external resources requiring more transmission use preferential treatment.

5.C.2.4. A Secondary Market For Import Allocations

In the event that existing capacity commitments do not receive priority in the allocation, a LSE that relies on those resources to meet its RAR may need to acquire shares of import capability from another LSE. That is, if there is no evergreen provision, there will need to be a means to buy, sell, and trade shares. It remains unclear how exactly these transactions would occur. Those supporting a secondary market for countable imports suggested in the workshop that a bulletin board approach similar to the way inter-state pipeline capacity is transacted could be an option. Several parties highlighted that creating a secondary market for countable imports is unnecessarily complex, potentially inefficient, and may have unintended consequences concerning market power and lack of transparency. There were also questions concerning oversight of such a market. Concerned about the price another LSE could charge for an import allocation, Edison suggested that if a secondary market for import shares is developed, the price in the market should be capped.

5.C.2.5. “Use It Or Lose It” Provisions

Powerex supports a “use it or lose it” provision for the import allocation. If the Commission rejects an evergreen priority for existing resources, SCE also supports such as provision, although not necessarily the specific Powerex proposal. PG&E opposes a “use it or lose it” provision as unnecessary since it would contradict good business practices to have an allocation and not either use, trade, or sell it.

Powerex supports an approach whereby the “use it or lose it” would apply to any unused allocations after the LSE completes its month ahead reporting. Fifty percent of the post month-ahead unused allocation is open for use by other LSEs for the following RA year on a first-come first-served basis. The other LSEs can make use of this allocation for only one year and only if they have already used up their own initial allocation. After the one year that the unused allocation is used by the other LSE, it reverts to the original LSE. Any amount of the unused allocation that is not used by other LSEs would revert to the original LSE for use in the following RA year, 50% of the post month-ahead unused allocation is retained by the LSE for the following RA year.

The purpose of the "use it or lose it" provision is to maximize the ability of LSEs to depend on imports to meet the RAR by assuring that any unused import allocations are made available to LSEs that may be hindered from using imports to satisfy the RAR due to lack of import allocations. Such a provision implies a need for a secondary market for unused import shares. *Parties in their workshop comments should address whether the FPL/SCE alternative proposal for allocating based on share of peak load may resolve the needs for 'use it or lose it' provisions and the need for a secondary market for import shares.*

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

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

The CAISO's preliminary deliverability results found approximately 2300 MW to be undeliverable to the aggregate of load in the control area. The 933 MW of undeliverable capacity is located in PG&E, 1270 in Edison, and 160 in SDG&E's service territory. All but 10 MW of the undeliverable capacity in PG&E can be resolved by transmission upgrades already identified by PG&E. 1100 MW of the undeliverable capacity in the Edison's service territory are a result of recent transmission line de-rates. The transmission upgrades that could mitigate the criteria violation that make the capacity undeliverable have not yet been identified in Edison's transmission expansion plan. Overall, relatively minor transmission remedies or operating solutions would resolve the deliverability limitations found in the study. Given the preliminary deliverability findings the following options exist:

- Count all the generation as deliverable assuming that the transmission upgrades will be completed by the PTOs. This option requires a commitment by PTOs to complete the transmission upgrades within a reasonable amount of time.

- Disallow undeliverable capacity for counting toward the RAR until the transmission upgrades are completed. This option will require allocating the de-rates among the generators within the load pocket. A pro rate allocation of the de-rates to suppliers within a generation pocket seems the most equitable and simplistic approach.

In its stakeholder meeting on the study results the CAISO recommended that the existing units and imports be considered deliverable so long as the PTOs agree to complete the transmission upgrades by a date certain. Given that the reliability criteria violations that resulted in the undeliverable resources are low level reliability violations and require relatively lower costs fixes, the CAISO thinks the resources should be counted for RA purposes. *Parties should comment on the options above in their comments to this report.*

5.C.4. Preference For Internal Versus External Generating Resources

Parties highlighted that there may be instances, although very limited, where a generating facility internal to the CAISO control area located near an inter-tie, may degrade the import capability at the inter-tie. In that circumstance, a preference for internal versus external resources, for purposes of counting toward the RAR, needs to be made. The CAISO's preliminary baseline analysis results showed that this circumstance is not currently an issue. However, since stakeholders took the time to address this issue in workshops, the Commission should determine preference for internal versus imported resources so that LSEs will have the information regarding what counts toward for the RAR if the circumstance arises in the future.

Parties agreed that the advantages of showing preference for internal generating resources for purposes of counting towards resource adequacy include:

1. being physically located within the control area,
2. providing greater control and reliability, and
3. spot market imports are only available when adjacent control areas have a surplus.

The disadvantage of leaning toward internal generation is that California remains import dependent while undermining access to valuable imports.

There was consensus among parties that in the limited circumstance where import capability at an inter-tie would be de-rated due to the operation of a nearby generating facility, the inter-tie and internal generating facility should split the difference for purposes of qualifying capacity. In the future, if the CAISO's baseline analysis reveals that this is more than a limited circumstance or that splitting the de-rate between internal resources and inter-ties is problematic, the Commission can revisit the determination based on experience.

5.D. Liquidated Damages Contracts & Contract Language

Liquidated Damage (LD) Contracts are bilateral contracts that provide energy, capacity, or ancillary service products without reference to a specific unit or resource backing the obligation. Instead, such contracts provide services through a portfolio of generating units. The LD contracts' enforcement mechanism is through liquidated damage provisions as a remedy for breach of contract. In the energy industry, LD contracts provide that sellers shall keep the buyer whole for costs it incurs to remedy the seller's failure to deliver products or services as specified for in the contract. While LD contracts are considered firm by many parties because they employ liquidated damages provisions and can only be terminated for economic reasons, the inability to identify the resource providing physical capacity raises serious concerns for the Commission's ability to maintain the integrity of its RAR through counting conventions and deliverability requirements. Further, while liquidated damages can monetarily compensate the buyer, the buyer (and this Commission) nonetheless runs the risk of not having a resource available when it needs to count on it because a seller can use other economic considerations, such as comparing opportunity costs vis-à-vis the spot market and/or other regional markets to decide whether or not to comply. As an enforcement mechanism, liquidated damages provisions only ensure that the buyer is made whole – it does not provide the CPUC or CAISO the proper assurance that there will be "steel in the ground" to be available to maintain reliability. It is unclear whether the monetary damages that might be provided to the buyer actually compensate the electricity consumers for whom the buyer is simply operating as an agent.

The Commission acknowledged this concern in the Phase 1 decision on RAR but left it open to this phase to explore "proposals for contract language or other contract methods that can substitute for LD contracts, and we will explore whether audit methods can be developed that would allow us to place greater confidence in relying upon liquidated damage contracts." Further as D.04-0-035 notes, parties in Phase 1 could not reach consensus on how to treat existing contracts and how to transition their use under future RAR. On the one hand, some parties proposed continuation of their use at full value. On the other hand, others proposed counting existing LD contracts at full value but imposing a cap on their total use to limit their exposure on the system. In the middle were parties that proposed phasing out their use over time while allowing market participants to continue to use them.

In Phase 2 workshops, parties refined their proposals and identified other issues requiring resolution. Specifically, parties questioned:

1. What to do with existing LD contracts and how LSEs transition the use of LD contracts both in the short-term and in the long-term;
2. Whether the RAR supplant the CAISO's must-offer requirements. Parties need to know the nature and scope of their obligation to buyers or to the CAISO; and
3. What contract language could replace existing language to ensure compliance with CPUC Resource Adequacy Requirement.

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

There was consensus by all parties that existing LD contracts will not meet local area RAR. Parties recognized the inherent deliverability constraints associated with a portfolio mix of resources and that the lack of dispatchability would not meet the CAISO's operational requirements. While some parties continue to advocate for the use of LD contracts as an economic and reliable way to meet energy and capacity needs, those same parties acknowledged that because of the portfolio nature of the LD contracts, they would pose problems should the Commission impose specific local RAR. In Section 5.J. of this workshop report, we address local requirements.

AReM, Constellation, TURN, PG&E, ORA and Calpine each offered proposals on how to transition existing and newly signed LD contracts. Each proposal addressed to some extent:

- The required time period after the Phase 2 decision is issued which LSEs can continue to enter into LD contracts and have them count for RAR – essentially, a "grace period"
- The sunset of and limitations on the countability of LD (existing and newly signed, if any) for RAR,
- The term limits of the contracts signed after the Phase 2 decision but before LD contracts are no longer permitted to count for resource adequacy,

- The portfolio limits for which LD contracts may count for resource adequacy, and
- The need, and conditions, for waiver requests.

Additionally, at the February 16, 2005, workshop parties discussed whether there is a need for an audit mechanism to ensure supply sufficiency.

There was no general agreement on the length of time after the Phase 2 decision was issued that LSEs can continue to enter into LD contracts that would count for RAR. Calpine's position was that only LD contracts signed on or before October 28, 2004, (the effective date of the Phase 1 decision) should count for resource adequacy. PG&E proposed that current-form LD contracts signed after the effective date of the Phase 2 decision should not count for RAR. AReM, TURN and ORA proposed a "grace period" ranging between 90 and 180 days after the Phase 2 decision is issued which would permit a transition in the market to establish capacity products and allow LSEs to continue with business as usual. TURN further proposed that any firm LD contract signed within the grace period (in this case 90 days after the date of the Phase 2 Commission decision) would only be grand-fathered for 1 year to avoid a rush on newly signed LD contracts.

Some parties are concerned that there currently is no market for capacity products. Imposing a requirement for capacity could be costly for an LSE which relies heavily on LD contracts to meet its energy needs. Parties representing ESPs noted that they enter into contracts for energy services with their end use costumers. Any added costs such as those that might result from a capacity requirement, would be difficult to pass on to existing customers until the expiration of the contract. The Commission needs to balance the need to enforce RAR with the possibility that for some LSEs, a transition time will be required to phase out their heavy reliance on LD contracts.

It should be noted that while the Commission will adopt counting conventions to ensure RAR compliance, LD contracts will need to fit within those conventions only to the extent a LSE wishes those contracts to count for resource adequacy. LD contracts will continue to fill a needed function by providing energy.

Parties who advocated for the continued use of current-form LD contracts to count towards RAR noted that their use could be coupled with the CAISO system-wide "top-down"[30] resource balance accounting to ensure that California meet its resource requirements. In response, some parties expressed concern that a "top-down" approach would not provide the necessary detail to protect the integrity of the RAR. For example, current-form LD contracts that do not provide unit-specific information would be meaningless to the CAISO in matching with their system-wide resource balance. Ultimately, the CAISO needs unit-specific information. Some parties advocated that if the Commission were to permit current-form LD contracts' use to meet RAR, then it should also adopt an audit mechanism to ensure supply sufficiency. PG&E offered that a state agency, or the CAISO, tabulate resources plus a reasonable level of imports (as well as consider a reasonable level of exports) and compare that amount to forecast load. To the extent such reconciliation showed reserve levels below 15% in the market, the amount of LDs would be pro-rata reduced.

Parties generally agreed that existing LD contracts should have a sunset period, after which they would no longer count towards RAR. Most parties advocated that because there is no urgent need for physical capacity until the 2008/2009 timeframe, existing LD contracts should continue to count for capacity only until 2008. PG&E proposed that in addition to having a sunset date, existing LD contracts should be phased out to minimize the system's reliance on their use by 25% per year based on the portfolio amounts. For example, PG&E proposed a specific percentage of firm LD contracts that could qualify towards resource adequacy obligations from 25% of total portfolio for deliveries in 2006 to 0% for deliveries in 2009. PG&E further notes that its proposal is not connected to the date each contract is signed to eliminate any incentive for parties to rush to sign large quantities of additional LD contracts with potentially long durations with the expectation that all LD contracts will be grandfathered. Parties representing ESPs noted that such a requirement would unduly burden them as they hold more energy needs through LD contracts than do IOUs. Furthermore, ESPs are unable to pass

[30] The reference to "top-down" in this section is not the same as the context identified in Section 5.A. "Top-down" in this section refers to a system-wide accounting of resources where the CAISO matches the system-wide peak demand with LSE RAR resources. In the context of LD contracts, the discussion centered on whether a global accounting would provide enough information to ensure that resources were not double-counted or that they were properly accounted for.

through incremental costs to end use customers without renegotiating existing contracts between the ESP and their customer. Imposing a capacity requirement on top of existing contract terms will make it difficult for ESPs to recoup added costs until after the contract terms. The Commission will need to carefully balance the need to enforce counting conventions to meet its RAR with the practical challenges facing ESPs' existing contracts with end use customers.

Finally, noting that in D.04-12-035 the Commission had stated that it "will not 'pay any price' or require [LSEs] to sign contracts that meet these requirements at any cost," AReM proposed that a waiver is need to protect both LSEs and end use customers against: (a) an unclear or perverse decision that the market is unable to deal with; (b) the market not developing in time; or (c) cases in which a generator or generators have market power (particularly an issue if LSEs are required to meet a local RAR). TURN offered as part of its compromise proposal that "the Commission must allow LSEs a waiver from these forward procurement requirements if market power rears its ugly head….but [that] any waiver must apply equally to all LSEs and not be applied in a discriminatory fashion." Constellation requested that if the Commission were to adopt any form of waiver protection, the Commission would need to very clearly identify the conditions under which a waiver would apply. The Commission should not leave it to an LSE to identify through a waiver request the situation that gave rise to such request. Rather, a list of clearly articulated conditions should be part of any waiver discussion in the Phase 2 decision.

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

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

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

5.E. Imports

The subject of how imports will be counted towards meeting LSEs resource adequacy requirement received limited discussion in both the Deliverability and Liquidated Damage Contract workshops. On February 24, 2005 Powerex circulated a straw proposal for the treatment of imports (see Appendix E). *Since the issues raised by Powerex were not fully discussed in workshops, parties are encouraged to discuss the proposal in the comments to this report.* Powerex highlights several issues that must be addressed in the phase 2 decision. These include:

1. Powerex believes that the Phase 1 decision determined that imports should count fully toward the RAR limited only by inter-tie transfer capability. Powerex cites the phase 1 workshop report, which determined that imports would count provided the contract: 1) is an Import Energy Product with operating reserves; 2) Cannot be curtailed for economic reasons; and 3a) Is delivered on transmission that cannot be curtailed in operating hours for economic reasons or bumped by higher priority transmission OR; 3b) Specifies firm delivery point (not seller's choice).
2. Powerex suggests that import contracts would not be limited to energy and that imports currently and would continue to sell capacity products, such as capacity call options. However, these call options may or may not specify a resource or set of resources. Powerex maintains that imports should not have to specify resources to be counted toward the RAR.
3. Powerex proposes that imports not be subject the to the must-offer requirements that are required of internal CAISO resources. Powerex maintains that the must-offer requirement for RA capacity resources denies it of the opportunity to re-market power if the LSE chooses not to exercise its option thus resulting in increased option costs.
4. Powerex maintains that a tagging requirement for imports is inappropriate as it would require identification of a specific resource, which is poorly suited to large hydroelectric systems and system resources.
5. Powerex believes that imports deliverable to an internal hub should be counted toward the RAR,

6. Powerex does not believe that imports must have Firm Transmission rights (FTRs) or Congestion revenue rights (CRRs) to count toward the RAR. Powerex suggests that the imports should count based on the availability transmission capacity over the inter-tie under normal operating conditions.

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

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

This topic was addressed in the June 15, 2004 Phase 1 Workshop Report but was not resolved in the Phase 1 Decision (D.04-10-035). Section 7.2 of the Phase 1 Report ("Allocation of DWR Contracts to All LSEs") concluded that:

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

The ALJ designated this topic for consideration in Phase 2. (November 19, 2004 Ruling, Attachment A, Topic No. 16 -- "Allocating DWR Contract Qualifying Capacity to ESPs".) AReM and TURN distributed straw proposals which were discussed at the February 8, 2005 workshop.

5.F.1. Should Any Allocation Be Made To Non-Utility Load Serving Entities?

Parties seem to agree, if only implicitly, that the resolution of this issue turns largely on whether non-utility LSEs (or their customers) currently pay for a portion of DWR contract costs and URG costs through mechanisms such as the Direct Access (DA) Cost Responsibility Surcharge (CRS) and the CTC. They are otherwise divided on this question.

Proponents of allocating a portion of the capacity value of these assets to non-utility LSEs maintain that most DA customers (i.e., those who are not "continuous" DA customers who are exempt from the DA CRS) pay a share of the costs of the DWR capacity through the CRS, and that all DA customers pay for URG capacity through the CTC. Proponents argue as a matter of equity that since ESP customers pay for a share of this capacity, ESPs should be able to use a proportionate share of that capacity in complying with RAR.

Opponents of allocating any portion of DWR capacity to Energy Service Providers (ESPs) maintain that DA customers only pay a portion of the above-market component of DWR and QF contracts. In contrast, the opponents argue that bundled service customers pay the full amount of the market value of such resources and, due to the 2.7 cent cap on the DA CRS, they currently pay a greater than proportionate share of the above market component of such costs. Moreover, due to the deferred recovery of the balance of above-market costs from DA customers, it is impossible to determine how much, if any, of the above-market DWR costs will ultimately be paid by DA customers.

5.F.2. Allocation Method

Three primary proposals focusing primarily on allocating resources to ESPs (not CCAs) were offered:

1. **Allocation of DWR Contracts:** DWR contract capacity would be assigned to the LSEs on a pro-rata basis based on their forecast contributions to non-bond related DWR Revenue Requirement. For LSEs serving non-continuous DA customers, this would be the DWR Power Charge portion of the DA CRS. The DWR capacity allocated to the ESPs (via DA customers) is to help meet the month-ahead planning reserve requirement; the resources to serve the energy needs of their DA customers will be procured elsewhere. This credit for a slice of DWR capacity is not controlled by the ESP and cannot be dispatched by the ESP. It is used only to provide (a portion of) the ESPs' contribution to the additional capacity needed to meet the system-wide RA requirement.
2. **Allocation of URG:** URG capacity will be assigned to the LSEs serving the retail customers pro-rata based on their forecast contributions to the costs of the resources. The URG capacity allocated to the ESPs (via DA customers) is for meeting the month-ahead planning reserve requirement; the ESP will procure the power to serve their DA customers elsewhere. The energy associated with this slice of IOU system

capacity is not controlled by the ESP. It cannot be dispatched by the ESP. It is used only to provide (a portion of) the ESPs' contribution to the additional capacity needed to meet the system-wide RA requirement.

3. **Allocation of DWR and QF Contracts:** Allocate an equivalent portion of *both the power itself and the cost of that power* to DA customers. Under this approach, if a given IOU service territory had 15% DA load, then 15% of that utility's DWR power would be "deemed delivered" to those DA customers, and those customers would pay DWR the full cost of that power, just as bundled customers would take delivery and pay for the remaining 85%. To eliminate the problem of allocating dispatchable resources, this proposal could be limited to only non-dispatchable DWR and QF resources. This should fit well with DA customers' typical load shapes, which tend to be more "baseloaded" than aggregate bundled customer load.)

5.F.3. Allocation Issues For CPUC Decision

At issue is whether non-utility LSEs should be allowed to use an allocated portion of the capacity value of the DWR contracts and URG (including QF contracts) in their RAR filings. This question might be decided differently for DWR contracts and for URG.

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

5.G. Wind And Solar Resources Without Dispatchable Backup

In the initial Workshop Report on Resource Adequacy Issues, two options were identified for identifying the qualifying capacity of wind-powered and solar generation without dispatchable thermal back-up generation: Option 1 would count historical production during peak hours; option 2 would adjust net dependable capacity by the rate of Effective Load-Carrying Capacity (ELCC).[31]

The Commission reviewed the alternatives discussed in the initial workshop report and chose "the historic performance approach, but require[d] that it be determined in such a way as to reveal monthly differences in performance. Further, we require that historic performance be computed over the QF Standard Offer 1 (SO 1) on-peak period only. Finally, we are open to segregation of performance by different wind resource area, but require any party proposing this to provide persuasive data supporting this approach. Since we do not wish this detail to distract us from implementing the first generation of these requirements, we will review any proposals for different treatment of wind resources as part of the second generation of these requirements."[32] Workshop participants discussed this issue at a session on December 6, 2004 in Folsom, with some follow-up discussion in San Francisco at a session on January 19, 2005.

Despite the Commission's stated choice of the historical performance method over the Effective Load-Carrying Capacity (ELCC) model by the Commission, there was still some advocacy for the ELCC method being more objective than relying on historical information. However, given the Commission's preference for evaluation based on historical performance, the specific issues facing the workshop participants were:

- How much history should be used for the analysis?
- What hours should be used for evaluation of the peak period?
- To what degree should different types of generators be measured separately?
- One issue not discussed by participants, but worthy of consideration, is what process should be used for updating renewable-specific capacity assessments.

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

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[31] June 15, 2004 Phase 1 Workshop Report, p. 26

[32] D04-10-035, Section 3.5.3, pages 24-25.

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

Workshop participants noted that there is not a large body of historical evidence regarding the performance of solar and wind generation. The history is very much unlike that of hydroelectric generation, where rainfall and generation statistics are available over many years. The commercial solar and wind industries are much newer. In addition, performance of solar and wind generation has been increasing over time. Capacity factors in recent years have been greater than in the more distant past as new generating units have been installed and older units retired. The historical information that is most relevant to estimating next year's generating performance is, for this reason, the most recent results; relying on old information taken from too long a historical time period can result in understatement of estimated future capacity factors. So for the sole purpose of keeping up with the latest progress, the most recent history would be the best.

Unfortunately, each year is filled with special events, storms or the lack of, wind or the lack of, with atypical generating results likely to affect each individual month of observation. A month is a very short period for analysis, even shorter when only the on-peak hours are included in the estimate. Therefore, for the purpose of avoiding idiosyncratic estimates for a particular month of the next year, a long history would be best because an average of many examples of that month would smooth out the variability among individual months.

Participants in the workshop reached a near consensus that the best compromise would be a three-year rolling average performance history. For example, for June 2006, the generation results for June 2003, 2004, and 2005, should be averaged.[33] Workshop participants considered this a short enough timeframe not to be too downward biased because of technology changes, yet long enough to smooth out the variable results of any one particular year. A rolling average has the additional benefit of updating the sample by one-third each year, keeping it as fresh as possible. This method is not entirely satisfactory to CALWEA, which would prefer to use ELCC.

[33] If 2005 data is not available, the most recent available data from the previous three years could be used.

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

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

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

The peak demand hours of the day vary across the months. It would be possible to develop specific profiles for each summer month and each non-summer month. However, reasonableness and ease of administration argue in favor of a simpler method. Workshop participants discussed two options for the summer months: (1) the SO1 contract summer peak hours, noon to 6:00 p.m.; and (2) the CAISO-calculated peak hours of 3:00 p.m. to 7:00 p.m. It was generally agreed among the participants that since there are good records readily available regarding the SO1 hours, reliance on data SO1 hours would be the preferable choice.

The question becomes more complex once the non-summer months are included. The SO1 contracts have a different nomenclature for the non-summer months that does not include a set of peak hours. Instead there are mid-peak or partial-peak hours. The CAISO peak hours are once again different from the SO1 contract mid-peak hours. The CAISO peak generally falls in the range of 5:00 p.m. to 8:00 p.m. in the non-summer hours. Again, and for the same reasons, it was generally agreed among the participants that the SO1 hours would be the better choice for monitoring performance, for the contracts are already set up that way.

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

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

Every new batch of solar and wind generators is more efficient than the last. It would be ideal to develop expected capacity factors for each new model separately. That would be impractical, for new equipment does not have a historical base of operations in place. (It should be noted that advocates for an ELCC-based qualifying capacity consider this fact to be a defect of the historical-based system.) Participants in the workshop discussed the idea of breakouts by technology and/or by vintage, as well as by area where the generators are deployed. This discussion did not result in complete consensus, only partial consensus. It was generally agreed that historical generation should be calculated from California's several wind regions separately. Within each region, the simplest method of calculation would be to use the capacity factor for all wind units as a whole. It would be more complex to subdivide into more categories, such as technology types or vintages. The additional benefit to overall resource adequacy of further subdivision would be small. But the effect for individual contractors could be substantial. A contractor with the latest and most efficient equipment would be favored by having output from that type of equipment, or the newest vintage of equipment, measured separately from the overall stock of generators, some of which are much less efficient. The same total would result from either method, but the distribution of qualifying capacity could be substantially affected by the decision.

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

The Commission must decide whether it will be adequate to measure the historical generation overall for all of the units in a wind region, or whether a more fine measurement that breaks out technology types or vintages would be better.

5.H. Energy-Limited Resources

Participants in the initial resource adequacy workshops achieved consensus on a two-part rule for qualifying capacity of energy-limited resources. As stated in the June 2004 Phase 1 Workshop Report on Resource Adequacy Issues:

> Parties agreed that individual units must be available 4 hours per day for 3 consecutive days to be counted. In addition, an energy limited resource must be available a certain number of hours per month to be counted for that month. Parties agreed 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.[34]

The CAISO performed the calculation for the number of hours in each summer month that load was greater than 90% of the monthly peak, resulting in a range of 30 hours (for May) to 60 hours (for August). Participants also agreed that individual resources could be counted for some months even if not for all, and that individual resources that meet the hours/days requirement can add together to meet the monthly hours obligation.[35]

The Commission agreed with the conclusions of the workshop participants on the applicability of the two tests.[36] But the Commission noted that the rule on hours where load was greater than 90% of the monthly peak was developed in the context of an evaluation of the summer months only. Therefore, the Commission decided, "the application of this rule should be limited to the summer months. The development of an appropriate rule for energy-limited resources for non-summer months should be discussed in Phase 2.[37]

Workshop participants discussed this issue at a session on December 6, 2004 in Folsom, with some follow-up discussion in San Francisco at a session on January 19, 2005.

Generally, it was agreed that for the summer months, the Commission's two-part test is adequate and appropriate. Both the three-day-by-four-hour rule and the hours-above-90%-of-peak rule are appropriate for the kinds of load shapes seen in the summer months. In effect, that rule means that energy-limited resources must be stacked to be able to meet a minimum of 60 hours of operation during August, with smaller numbers in the surrounding summer months.

But there was considerable discussion and less agreement regarding the situation for the non-summer months. Load shapes are less peaked in the non-summer months, with the result that the number of hours with loads in excess of 90% of the peak could be much higher, as much as 270, or even 300, hours in some months. The utilities argued that it would not be appropriate

[34] June 15, 2004 Phase 1 Workshop Report, p. 24

[35] June 15, 2004 Phase 1 Workshop Report, p. 25

[36] D.04-10-035, Section 3.5.5, p. 26.

[37] D.04-10-035, Section 3.5.5, p. 26.

to nominate energy-limited resources as planning capacity for such long periods during the non-peak months. If the qualifying capacity of energy-limited resources has to meet such long expected run times, the capacity will be severely degraded. Moreover, operation in the non-summer months for long periods would not be the best use of such resources. The utilities, particularly Edison and PG&E, argued that the Commission's second rule, that the aggregate of energy-limited resources must be able to operate for the number of hours during which load is above 90% of the expected peak, should be dropped for the non-summer months. Otherwise, the result will be to cause the utilities to contract for large amounts of capacity that will not be called upon, at great expense to customers who would not benefit. The utilities proposed instead that LSEs be required to nominate capacity that can meet the load shape over the non-summer months and not apply the 90% rule.

Much of the concern about the number of hours that energy limited resources can be counted upon results from an assumption that reserves can be procured in a pattern that matches the expected daily load shape. Therefore, for example, a portfolio of energy limited resources calculated to be capable of serving for 60 hours in August may be counted to cover the peak hours for that month, thereby satisfying the August reserve requirement for the entire month.

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

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

Last year's initial Workshop Report on Resource Adequacy Issues stated that, "The issue of when you can count resources under construction is driven by the fact that the resource adequacy showing is made the year-ahead and there is considerable uncertainty as to whether projected online dates of projects are realistic."[38] The Commission determined that, "the databases maintained by the CEC and CAISO are the appropriate foundation for determining

[38] Page 36.

[Commercial On-Line Dates]. We direct that parties flesh out these proposals in Phase 2. We wish to establish whether the CEC and CAISO are willing to make modifications to track projects more closely and to allow these updated data to be accessed publicly for use by LSEs in their compliance filings."[39]

Workshop participants discussed this issue at a session on December 6, 2004 in Folsom, with some follow-up discussion in San Francisco at a session on January 19, 2005.

There are databases of expected on-line dates for new generating units already publicly available from the CAISO and the CEC. The Commission determined that those databases should be the foundation for determining CODs.

The primary elements of importance, or criteria for an appropriate COD policy that were discussed in the workshop were:

- Can there be a specific procedure and specific criteria for a Commercial On-Line Date, noting that this is different from ratemaking? The CPUC already has in place ratemaking criteria for rate-base treatment. This is not the same issue.
- It should be clear about what is to be measured: the operating date from the point of view of reliability of the system, the date of accountability for the LSE.
- There should be one list only for this purpose, and the list should extend out multiple years. While there are multiple lists in place now for licensing and other purposes, there should be only one list for this purpose.
- There should be regular updates and standard publication dates, such as monthly. Regular publication allows resource providers, LSEs, and policy makers to expect information to become available at certain times, and avoids surprise. Episodic or irregular publication dates are not appropriate for the purpose of establishing eligibility to count resources for RAR.
- There should be a standard process of verification that is clear, consistent, and contains a dispute resolution process. This is an official process with official results that resource providers, LSEs, and policy makers can count on.
- The publication of the list should be an official action that follows an official process; it should not be ad hoc or without accountability.

[39] D04-10-035, Section 3.5.7, pages 28-29.

- While the list should be public, the submissions from LSEs should be confidential, for there are commercial aspects to the information that is filed.

Workshop participants discussed a proposal at the December 6 workshop session for the CAISO and CEC to cooperate in developing a reporting method that would meet all of the above criteria. Their work resulted in a working proposal document distributed to the working group on December 23, 2004.[40] The CAISO-CEC working proposal is attached to this workshop report as Appendix F.

The essence of the proposal is that the CAISO and the CEC would jointly create and post monthly, on a public website, a new report, created specifically for the use of LSEs for resource adequacy, that lists the expected date of commercial operation as reported by the developer of each resource under construction or with an expected date of commercial operation of one year or less, that has a nameplate capacity rating of one MW or greater. For the annual year-ahead showing of resource adequacy, an LSE would be able to include, for any given month, a resource that is still under construction provided that the latest revised date of commercial operation posted on the public web site is no later than the first calendar day of the applicable month, and the operational status is expected to be achieved no less than 60 days prior to that date. A resource that meets those criteria would be considered to have achieved qualified status for the year-ahead showing. For example, a resource that the developer reports is expected to achieve commercial operation no later than July 1, 2008 could be used by an LSE in its September 2007 report to demonstrate compliance in its year-ahead showing for the month of July 2008. For a month-ahead showing of resource adequacy, qualification of a resource is dependent upon the unit having achieved operational status 60 days prior to the month in which it would be counted for resource adequacy purposes. For example, if a month-ahead showing for the month of August 2011 required a month-ahead filing by June 30, 2011, that filing could only include a resource that had achieved operational status no later than June 1, 2011.

[40] Proposal #2 developed in cooperation between the CAISO and the CEC, “Counting Resources under Construction and Estimating Dates of Commercial Operation.”

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

5.J. Local Resource Adequacy Requirement

D.04-10-035 determined that local requirements must be a component of the overarching resource adequacy framework to assure that LSEs can serve their customers and the CAISO can maintain grid reliability. The development of local RAR was earmarked for phase 2 workshops. The CAISO developed working proposal for establishing local capacity requirements as a starting point for discussions at the December 8, 2004 workshop. Parties asked a number of clarifying questions and raised substantive issues with the initial proposal. In response to the feedback from the first workshop, the CAISO revised the initial local capacity proposal for discussion at the January 25-26, 2005 workshops (see Appendix G).

The revised proposal resolved many of the more problematic issues surrounding the initial working proposal and is the basis for the issues outlined below (see attached CAISO revised local capacity proposal dated January 25, 2005). There was largely consensus among parties with respect to how the CAISO will go about establishing a local capacity requirement. However, given that issues such as cost allocation and pricing for CAISO supplemental procurement, and local market power mitigation are FERC jurisdictional, the locational capacity procurement framework is somewhat incomplete. Overall, all parties agreed that implementation of a capacity market construct would address many of the more difficult implementation and coordination issues that embody the local RAR.

5.J.1. Definition Of A Local Reliability Area

The defined local areas are a factor of physical constraints on the transmission system and the set of generating units within the local area. The defined local area will be established in the transmission planning process and developed using the PTOs load forecasts. Put simplistically, the local area will be a factor of the transmission transfer capability into a particular area and the PTOs' forecasts of load within that area. If the transfer capability is less than the load, given the reliability criteria discussed further below, the LSEs would have to procure enough capacity within the local area to satisfy the requirement. The CAISO proposes to identify local areas in a stakeholder process. The defined local areas are intended to remain relatively stable over time and would be updated when transmission upgrades increase the transfer capability into the local areas thus reducing the local capacity requirement.

No party provided criticism of the CAISO's approach to defining the local areas. However, the issue of how generator effectiveness within the local area contributes to the local area definition was discussed at length. There are essentially two approaches that the CAISO could take in defining the local area.

In the first approach, the CAISO could define the local area more precisely resulting in each local generating unit being equally effective in resolving the transmission constraint. This approach would result in a smaller pool of units within the defined local area that could satisfy the requirement and thus increases market power concerns. This approach may also undermine the ability of smaller LSE to meet the local requirement.

In the second approach, the CAISO could define the local area more broadly thus resulting in a larger pool of units within the defined area that could satisfy the local requirement. A larger set of local resources, however, reduces procurement precision as not all the units are equally effective in resolving local constraints. Defining the local area in a way that increases the pool of resources that can meet the local requirement increases the likelihood that smaller LSEs can meet the requirement and reduces, but does not eliminate, market power concerns. Given that local procurement will be less precise under this approach, it assumes a larger role for the CAISO in supplemental procurement than the first option.

There was consensus among workshop participants that defining the local areas more broadly was the preferred approach. The trade-offs inherent in this approach toward defining the local areas are that it increases the ability of LSEs to meet the requirement and reduces market power. However, it increases the role for the CAISO in supplemental procurement since defining the local area more broadly reduces procurement precision.

5.J.1.1. Timing Of CAISO Supplemental Procurement

Workshop participants agreed that 100% of local capacity requirements must be met on a year-ahead timeframe for all 12 months of the year. This is a necessary because the CAISO will not know until after the LSEs report how they plan to meet the local capacity requirement whether supplemental procurement is required. After the LSEs report, the CAISO will require sufficient time to undertake an analysis to determine if supplemental procurement is required and, if so, engage in a process to secure the resources it needs to maintain local reliability. The CAISO cannot reasonably be expected to engage in supplement procurement if it does not know until the month-ahead report whether it has the resources in requires.

Having all local capacity procurement occur on a year-ahead basis for all 12 months introduces a set of implementation and timing considerations that were not anticipated when the Commission established the 90% forward commitment requirement for the 5 summers months to be reported in September. Given that the year ahead reporting requirement is not a rolling 12 month obligation, the September showing will have to demonstrate that each LSE has procured 100% of the local requirement for each month of the next calendar year.

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

Parties should also comment on whether changing to a rolling 12-month obligation might prove more efficient.

It should be noted that while the current RMR contract is the likely interim method to secure the supplemental resources, we do not anticipate that the CAISO will conduct what is today's RMR process. Rather, in the event the CAISO requires additional resources, it will engage in a bilateral negotiation. However, there will be a necessary transition out of the existing RMR contracts given that the RA requirements are not effective until June 2006 and the existing RMRs are a year in duration. So that the LSEs will know their local requirement prior to the 2005 reporting requirement, the CAISO proposes to use the existing RMR areas to establish the requirement for the first year.

For future years, the CAISO proposed two timing and process options for developing the LSE local capacity requirement and conducting the CAISO's supplemental procurement (see

Tables 4 and 5). These options do not address the transition between today's RMR process and the forthcoming local capacity requirement framework. In both options the LSEs will have their local capacity requirement in May of each year. The predominant difference in the two options is the timing and process for CAISO supplemental procurement. Option 2 is driven by the September 30 LSE reporting requirement and thus results in a 3-month delay in the CAISO supplemental procurement process (April 1 as opposed to January 1 in Option 1). It seems that the CAISO's supplemental reliability contracts could undermine the ability of the LSE to secure the unit in the following September forward commitment process. A possible solution to minimize this effect would be for the CAISO to only sign shorter-term reliability contracts (e.g. 3-6 months). Option 1 has the advantage of completing CAISO supplemental procurement in January and thus working more in concert with LSE procurement. That is, it may allow the CAISO's role in procurement to be truly supplemental. Option 2 however, has the downside of having the CAISO fully in the market at the same time LSEs are procuring to meet forward commitment obligations.

Table 4

CAISO Option 1

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

Table 5

CAISO Option 2

End of January	ISO requests base cases and load forecast for the following year from the TOs and LSEs.
February-March	TOs develop Base Cases and Load forecast for the following year.
End of March	TOs provide complete local area and system base cases and load forecast for the following year to the ISO. [TOs already submit this information along with proposed transmission projects as part of their participation in the ISO's transmission planning process.]
April-May	ISO performs RAR Technical studies to determine the local areas and the capacity requirements (in MWs) within those local areas.
May	ISO issues Draft RAR technical study which identifies the capacity requirements in each local area.
May	ISO conducts Stakeholder Meeting(s) to discuss these RA locational Requirements.
End of May	ISO issues Final RAR technical study with locational requirements.
June-July	LSEs review options for meeting locational requirements and make procurement.
August	ISO issues RFP for back-up reliability contracts.
September 30	LSEs' year-ahead showing for locational capacity requirements.
October	ISO analyzes how LSE contracts for meeting locational requirements would meet reliability needs inside each load pocket.
October	Deadline for responses to ISO's RFP for back-up reliability contracts.
November	ISO issues draft recommendation for back-up reliability contracts.
November	ISO management issues final recommendation for back-up reliability contracts.
December	ISO Board acts on management's recommendations.
January	ISO modifies or signs back-up reliability contracts and prepares FERC filing.
February 1	ISO files with FERC on rates and back-up reliability contracts, as required for 60-day notice.
April 1	Back-up reliability contracts take effect for a one-year period.

The CPUC and CAISO must create a schedule that provides adequate time for market participants to meet their RAR, while balancing the need for LSE compliance filings to be submitted to the relevant state agencies with sufficient time for review. The CPUC should establish a timeline for meeting the RAR.

5.J.1.2. Local Capacity Requirements & Transmission Planning

Several workshop participants, ESPs in particular, wanted assurance that transmission upgrades will be considered as a means for resolving local area constraints for the purposes of reducing the local area capacity requirement. Market participants acknowledged that the PTOs that propose transmission upgrades are not the same entities that are paying the local procurement costs associated with meeting reliability. Therefore, it is critical that LSEs participate in the CAISO transmission planning process and propose alternatives to enable a proper trade-off analysis to occur.

The local requirement will be established annually in the transmission planning process. New transmission projects that could impact local constraints, and thus the local capacity requirement, will be proposed and addressed in that process providing LSEs an updated local requirement for the next year. After considerable dialogue about whether an annual update to revise the local obligation may undermine goals of longer-term contracting, it was acknowledged that major transmission additional that could impact local constraints require 3-5 years of planning and online dates often change dramatically. Since the transmission planning process is an open forum where anyone can participate, LSEs will have knowledge of upcoming transmission enhancement and can incorporate that knowledge when evaluating the duration of contracts for local resources.

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

The CAISO proposes to base the local area reliability criteria on a 1 day in 10 years load forecast. Defining the local area reliability criteria based on 1-in-10 year loads is a practical solution as a starting point. Parties did not oppose this approach. Several participants asked the reason for differences in the reliability criteria for system, zonal, and local requirements. The CAISO responded that a 1-in-10 year load criteria in local areas is necessarily more conservative than the 1-in-5 year for zonal or the 1-in-2 year for system because there is less resource diversity in local areas and thus a reduced ability to respond to contingencies.

The 1-in-2 year system reliability criteria is consistent with planning practices. The 1-in-10 year reliability criteria supports operational requirements. Most parties agreed that the CAISO must plan to meet local operational requirements recognizing that the underlying reason the Commission is establishing local capacity requirements is because the existing RMR process, which is based on a 1-in-2 year planning process, fails to meet operational requirements. ESPs suggested that local requirements be met through a 1-in-2 year planning criteria thus reducing the local capacity obligation. However, ESPs were not able to explain how additional resources necessary to meet operational requirements in local areas would be acquired if the 1-in-2 year planning criteria were continued.

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

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

A working group of IOUs, ESPs and the CAISO developed an initial preferred approach for establishing each LSE's share of the local megawatt requirement that must be procured within each local area. The preferred approach, referred to as the 'bottom-up' approach, would require the CAISO to first determine the list of buses and banks within each load pocket. The IOUs would then determine the geographical and electrical boundaries of the pocket. The IOUs would then use some metric, such as Zip codes, to provide the information to the ESPs to calculate their respective share of the historic bus bar loads in the local area. The IOUs would also investigate whether their settlement and billing systems could provide data to calculate the IOU and ESP allocation of peak load within the pocket. The participants noted that the task of calculating LSE's load share with local areas would be easier for ESPs than IOUs since they have fewer customers and use billing systems that are more directly targeted to individual customers.

Parties agreed that this was a complicated, though not impossible, task that could be completed within the timelines established for the CAISO deliverability analysis. In future years, the CAISO will use the transmission planning process to establish allocation of LSE responsibilities within load pockets. Approximations may be appropriate until load pockets are more stable. With the emergence of an annual allocation of local capacity to LSEs, there is no reason that LSE-specific attribution of customers to substations, busses or distribution circuits cannot be routinely implemented. Such updates to the allocation may possibly be conducted as part of the load forecast review process.

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

5.J.4. Challenges For Local Capacity Requirements

Most workshop participants agree that local procurement should be addressed through resource adequacy and that the existing RMR contacts fail to assure local area operational requirements. In addition, no party disputed that transmission is necessarily a component in reducing the number of local constraints and thus the associated local capacity costs. Furthermore, that the CAISO's reliance on must-offer resources to meet local and broader operational requirements is unsustainable and does not provide for a stable means to assure sufficient resources in the long-term, was not disputed. Nevertheless, there are challenges in establishing local capacity requirements.

5.J.4.1. Local Market Power

Market power is inherent in the problem that a given amount of generation within a constrained area is necessary to maintain reliability and serve load. Today the local requirements are met through RMR and must-offer resources, neither of which provides a sustainable platform for investment and assuring that resources remain available. Furthermore, neither of the current means for the CAISO to procure local resources seems to be providing the PTOs with the correct incentive to reduce the number of constrained areas.

While the CPUC is establishing the local capacity requirements, FERC has jurisdiction over market power mitigation. The jurisdictional divide on this issue creates uncertainly and potential risks for LSEs. It should be noted, however, that it is easier for FERC to monitor and mitigate centralized markets than the bilateral transactions currently under development this proceeding. Nevertheless, adequate local market power mitigation by FERC and strong penalties for non-compliance should influence bilateral transactions. So long as there is not a centralized capacity market that can be monitored and mitigated, long-term contracting and transmission alternatives may be the best means of managing market power.

5.J.4.2. CAISO Role In Backstop Procurement

The CPUC does not have jurisdiction over the price or cost allocation of CAISO procurement activities. While the CAISO backstop role is necessary in the near term, the CPUC is setting forth a structure without a definitive rule by FERC regarding price and cost allocation. Furthermore, cost allocation disparities in CAISO procurement and CPUC resources adequacy procurement would likely continue to perpetuate disincentives to enter into contracts. It is critical that CPUC and FERC's allocation of procurement costs are aligned in accordance with cost causation principals that provide the correct incentives to reduce reliance on CAISO procurement. To assure that the proper incentives for RA procurement exist, it is important to differentiate between procurement that occurs to meet load, which should be paid for by LSEs, and the transmission reliability service costs, which are socialized under the CAISO tariff. If CAISO procurement related costs are considered reliability services as opposed to backstop procurement, and thus socialized, perverse incentive to rely on CAISO procurement will continue.

5.J.4.3. Buyer Monopoly & Small Local Requirements

There is a possibility that smaller LSE will not be able to meet the local requirement because a larger LSE has already procured all or most of the local capacity. It is also possible that a particular LSE has a sufficiently small requirement to be commercially unattainable or not physically dispatchable. Both issues could be resolved by a capacity market structure or through a structure that allows parties to enter into bilateral arrangements. However, failure to meet local requirements is not an option as all load will will need to be served. Therefore, until a capacity market exists, one option is for the CAISO to use the penalties that LSEs pay for non-compliance in aggregate to procure listed capacity to make up the shortfall. The "pooling" approach would serve several purposes: 1) it would directly allocate the costs of CAISO backstop procurement to the LSE that did not meet the requirement; 2) it would allow smaller LSEs to meet the requirement; 3) it would reduce the number of transactions for larger generators that want to sell capacity; and 4) assure that all LSEs are equally meeting the local requirements.

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

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

5.J.5. Mirant Working Proposal

Mirant developed a working proposal in an attempt to address many of the outstanding issues facing locational capacity procurement (see Appendix H). The New York approach toward locational capacity procurement was the model for the proposal. The essence of the proposal is to establish a capacity market within each load pocket, implemented by the CAISO with the CPUC administering the capacity price. The proposal was presented in the final workshop and did not receive extensive discussion. Workshop participants generally liked the approach and agreed that it warrants further discussion. However, the Mirant approach will take time to implement and all workshop participants agreed it is not feasible for implementation this year.

Since the Mirant working proposal was developed, the Assigned Commissioner in the proceeding issued a Ruling notifying parties that Commission staff will be analyzing possible approaches towards capacity market development.

Chapter 6. Reporting, Review And Sanctions

The main issue for Commission consideration is how to measure compliance with resource adequacy requirements and the consequences for non-compliance. The Commission must also make a determination on what the specific obligation is on a year-ahead and monthly basis. D.04-10-035 stated the Commissions intention to provide sufficient clarity through guidelines and rules to support a compliance filing that will ultimately become a simple checklist.

6.A. Preliminary Load Forecast Reporting

D.04-10-035 briefly describes a process, now better understood as a result of workshop discussions, in which LSEs prepare and submit preliminary load forecasts to the CEC for review and processing. Section 6.B. will describe the review of these submissions in detail. This section addresses the reporting requirements for each LSE to enable this review and processing effort.

The January 13 and February 9, 2005, workshops addressed several facets of these reporting requirements, including:

1. scope of load forecasts,
2. schedule for submission of preliminary load forecasts, and
3. documentation requirements.

6.A.1. Scope Of Load Forecasts Submitted

The original premise of year-ahead reporting requirements was information for the five summer months of May-September only. Reporting and review for each of the month-ahead filings had not been discussed in Phase 1. Once month-ahead reporting was discussed two broad options emerged. First, parties could make very limited updates to what had been previously submitted for that month from the information submitted at year-ahead compliance filing. Second, more extensive updates for load forecast changes, revisions to resources covering loads and reserves, etc. could be allowed.

Once parties began discussing Month-Ahead load forecasts, and whether Month-Ahead filings could include updates to the load forecast submitted for these months in the year-Ahead filing, it became clear that the scope of the Year-Ahead review of load forecasts had to expand. Thus, parties have agreed that one of the consequences of year-round month-ahead obligations, not realized at the time that D.04-10-035 was written, is that the preliminary load forecasts submitted as part of the year-ahead process must include load forecasts for all twelve months of the year. Irrespective of the issue of whether or not the month-ahead filings for May-September allow load forecast revisions, the year-ahead compliance filing must include load forecasts for the entire year, and the CEC review process must make adjustments for the entire year. Sections 4.B. and 4.C. discuss adjustments for coincidence and programmatic impacts, respectively.

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

D.04-10-035 endorsed (pp. 16-21) the basic structure for the preparation of load forecasts as documented in the Phase 1 Workshop Report.[41] Key points of these load forecast requirements include:

- Load forecasts are based on the "best estimate" of future customer load served by the LSE
- Load forecasts are based on 1-in-2 peak demand weather for each month
- Load forecasts are hourly and include all losses and UFE
- Load forecast include reductions from the impacts of EE, non-dispatchable DR, and DG programs considered to be "committed"
- Load forecasts must be documented in terms of both methodology and input variables used to prepare the forecast
- Hourly historic data from the previous year should be submitted along with the forecast

[41] pp. 8-18 and Appendix B of the Phase I Workshop Report

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

Parties developed a hypothetical schedule for when LSEs must report preliminary load forecasts to the CEC, based upon the following sequence of events:

- April 1 – May 1: LSEs submit preliminary forecasts to CEC
- CEC reviews LSE-specific Load Forecasts for anomalies and makes two kinds of adjustments; EE/DR/DG impacts and coincidence
- July 1: final forecasts sent to LSEs for resource acquisition by CEC
- September 30: final compliance package to CPUC and CAISO. As discussed above, the CAISO must assess the need for backstop procurement.

A key issue for parties was the ability to receive final load forecasts back from the CEC by July 1 to allow sufficient time for final resource acquisition to meet load forecasts plus reserves. Backing up from this date leads to the April 1 to May 1 period for submission of preliminary forecasts to the CEC to begin the review process.

Clearly an April 1 submission date does not work for this first compliance cycle. In parallel with the workshop report comment process, the CEC will examine scheduling options and provide its advice to the CPUC.

The Commission must choose an annual spring filing date for preliminary load forecasts submissions, and a special date for 2005 reflecting the preliminary nature of the requirements for the first cycle. It must also choose a date by which final load forecasts are returned to LSEs.[42]

6.A.3. Documentation Requirements

This subsection describes the level of detail that each LSE will use in reporting its preliminary load forecast to the CEC. As noted earlier, the Phase 1 Workshop Report includes

[42] At least for 2005 filings, and perhaps each subsequent filing cycle, the CEC now suggests that the historic data be filed earlier by each LSE than its preliminary load forecast. A separate filing date for historic data will allow coincidence studies to be undertaken, and assure that data transfer issues are resolved prior to the critical load forecast review itself.

some consensus details that were adopted by D.04-10-035 in addition to the major policy decisions resolved there. The workshop discussions were intended to build upon this earlier effort and to flesh out the specific requirements for LSE load forecasts. In the workshop discussion, the following points were raised:

- Load forecast submissions encompass:
    - Load forecasts will need to encompass all months of the year, because it is impractical to use the month-ahead reporting process to make the necessary adjustments to the non-summer month load forecasts that will already have been made for the five summer months
    - Load forecasts should include hourly load values for each month
    - Load forecasts should include estimates of losses including distribution, transmission and UFE added onto customer-meter loads
- Load forecast documentation includes:
    - Current and projected customer counts
    - Projected changes in contract loads
    - Adjustments for municipal departing load and community choice aggregators projected to depart from an IOU in the forthcoming year
    - Description of load forecasting methodology including regression equations and other descriptive information
    - Other historic data needed to understand nature of load forecasting methodology
    - Historical hourly loads for the previous year
    - Historical hourly loads adjusted to normal weather, and the weather data and methodology used to make such adjustments.

The workshop process has clarified that in order for the CEC to determine what level of EE, DR, and DG impacts should be used to adjust the LSE's preliminary load forecast, that the LSE needs to document any such impacts it believes are already included in the preliminary load forecst and to provide a methodological rationale supporting this belief. As noted in Section 4.C. above and in Appendix D for the Topic 3-4 Working Proposal, there are complex econometric parameter estimation rationales that may justify assertions that some portions of total EE, DR and DG impacts have already been included in preliminary load forecasts. However, it is also noted that some load forecasting methods may not account for these impacts at all. The CEC Staff will require appropriate documentation and sufficient time to develop an independent opinion on these issues, which are likely to be unique to each LSE.

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

6.A.4. Confidentiality Issues

There were a number of issues about confidentiality of the preliminary and final load forecasts discussed at the January 13 workshop. The most fundamental issue is what portions of these filings are or should be classified as confidential. Most participants suggested that both preliminary and final load forecasts and all documentation should be confidential. Most participants were presuming that a mechanism like that used for the IOU long-term procurement plans in other tracks of D.04-04-003 would also apply for these load forecast submissions.[43]

Parties also discussed whether the CEC gets these filings directly or obtain them through the CPUC. Apparently some participants were concerned that it is CPUC confidentiality protections that they want to govern access to these data, not CEC safeguards, and they want it made clear that the CEC is acting as an agent of the CPUC. There are two options to achieve this goal that participants identified stemming from the Long-Term Procurement Plan phase of R.04-04-003:

- If July 2004 Ruling by ALJ Carew extending to the CEC collaborating staff the same access to, and rules governing use of, confidential data as CPUC/ED staff, then there is no issue;

[43] Similar data now being filed at the CEC may become public through the CEC's process.

- If CEC is not treated like CPUC/ED staff, then LSEs prefer that CEC obtain data using the same safeguards as established by the April/May 2003 Protective Order in R.01-10-024.

A number of workshop participants expressed interest in getting access to the LSE load forecasts under the sort of conditions outlined in the April/May 2003 Protective Order in R.01-10-024 or the January 2004 Protective Order now operative in R.04-04-003. For example, IOUs want to see the ESP, MDL and CCA load forecasts for any departing load from their own current bundled customers. Traditional procurement process interveners want to be able to access ESP and CCA load forecasts as they have had access to IOU load forecasts to understand possible cost-shifting to bundled service customers. These access interests raise the following issues:

- Should access be limited to just the CEC and CAISO? If an entity other than the CEC and CAISO gets to see an LSE's load forecast, under what conditions is this allowed?
- Are the provisions of the "FERC model" adopted in the January 2004 Protective Order in R.04-04-003 the appropriate starting point for the comparable access to confidential data pertaining to resource adequacy load forecasts and supporting documentation?

Finally, parties discussed a number of specific details of confidentiality protection process that would have to be resolved. These included:

- Participants discussed whether these confidentiality arrangements should be made on a "programmatic" basis for all LSEs, or whether there would be an order unique to each LSE.
- Is the April/May 2003 Protective Order from R.01-10-024 the appropriate starting point?
- Given that confidentiality safeguards need to be created to minimize any loss of time following submission of the LSE load forecast filings proposed for April 1, 2005, should these arrangements be created in advance or only once the LSE files its information?

The CPUC must make decisions about what will be confidential and for how long. It must decide the process that it will use to provide necessary access by the CEC and CAISO as agents of the CPUC. The CPUC must decide whether and how to allow access for discretionary purposes by allowing interested parties to judge whether their interests are being protected. The mechanisms to implement these decisions may need to be put in place prior to the forthcoming Phase 2 decision to allow preliminary load forecasts to be submitted on the schedule necessary to assure that compliance filings can be submitted in this calendar year.

6.B. Preliminary Load Forecast Review

D.04-10-035 directs the CEC to review preliminary load forecasts from LSEs to determine plausibility and to make certain adjustments that an LSE cannot make by itself. The debate between "current customer" and "best estimates" resolved by D.04-10-035 reflects concerns that parties may somehow "game" their load forecasts to avoid making appropriate resource commitments and thus avoid costs and perhaps jeopardize system reliability. Plausibility assessment is that portion of a review intended to detect such "gaming." The adjustments include coincidence adjustments to recognize diversity of load shapes, and EE, DR, and DG program impact adjustments. Finally, a comparison of the aggregate of all LSE load forecasts to an overall CEC and/or CAISO load forecast is an additional way to be more confident that load is not "falling through the cracks."

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

Step 1 of the review process is a determination that the individual LSE load forecasts are plausible. The concern expressed in D.04-10-035 is that LSEs may attempt to "lowball" their load forecast in order to reduce compliance costs. A secondary element of this step is to review the methodology description. Participants in the January 13 workshop had the following questions:

- What is the basis for plausibility assessments?
- How would this make use of the "customer count" data required by D.04-10-035?
- How does the CEC intend to "interact" with the LSE if issues arise?
- What does the CEC do with the data when it is finished with its review?

The CEC Staff indicated that it intends to compare historic versus projected customer counts and to compare the LSE LF with the previous year's actual hourly loads in its review of plausibility. In discussing the CEC's proposed approach and the issues, parties proposed that the focus be on "anomalies" identified for specific LSE load forecasts. Further participants recommended that the CEC should provide its initial assessment to the LSE, as part of a dispute resolution process, that might resolve some concerns as mistaken interpretations of LSE filings or that are simply based on LSE mistakes in reporting. The parties support a review process in which the LSE should be allowed to resolve concerns identified by the CEC by filing corrected or supplemental information during the review process. Both ESPs and IOUs want to have the results of any corrections or modifications held in confidence. The issues of confidentiality are discussed in detail in Section 6.A.4.

Assuming the CEC may on occasion find that it has concerns with an LSE's load forecast that cannot be resolved by discussion with the LSE, what happens? The following issues were identified but not resolved:

- Does the CEC simply report individual LSE implausible load forecasts to the CPUC and wait for CPUC action?
- How should the CPUC organize a dispute resolution process? What is the timeline for resolving such disputes?
- For the loads represented by such an LSE, are default procedures used that would permit aggregate load forecast comparisons to proceed?
- Would the CPUC need to issue annual decisions on the adequacy of LSE plans?

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

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

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

Step 2 of the review process is to make all appropriate adjustments to each LSE's load forecast. Two adjustments have been discussed: (1) coincidence, and (2) EE/DR/DG impacts.

Coincidence adjustments are called for in D.04-10-035, Section 3.4.1, so that the basis for reserve requirements and qualifying capacity resource commitments is effectively the LSE's contribution to aggregate load at system peak conditions. At the November 30, 2004, workshop, the focus was on the set of hours in which LSE loads are greater than 90% of the peak, and the issue was whether the reference was the LSE's own peak for each month or the system peak for each month.

The second factor is the adjustment of each LSE's load forecast for the impact of EE/DR/DG program impacts. This effort is described in detail in Section 4.C. of this workshop report. While the main concept of an adjustment is clear, some details remain to be resolved as noted there. Parties did not resolve whether if the CEC believes adjustments are needed, does it have the discretion to do this, or must the CEC inform the CPUC who will then formally require an adjustment?

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

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

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

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

Having reviewed individual LSE load forecasts for plausibility, and corrected any problems that exist, and having adjusted the preliminary/corrected load forecasts for coincidence and the impact of EE, DR and DG programs, a third step may be worthwhile.

Participants asked whether the aggregation of load forecasts summed across all LSEs should be compared to CEC and/or CAISO short-term load forecasts? Parties agreed that such comparisons were appropriate. LSEs agreed that adjustments to preliminary load forecasts may be needed if the discrepancies are too large. Parties were unclear whether existing CEC and/or CAISO load forecasts were prepared on the same basis as the load forecasts directed by D.04-10-035, and were emphatic that having comparable load forecasts used as a references was essential.

It is widely known that the CEC and CAISO make short term load forecasts as part of overall California supply/demand balance assessments several times per year for presentation to the Governor and legislature. Generally these load forecasts include multiple scenarios. Recently, NP15 and SP15 breakouts have been provided. A standard 1-in-2 peak weather scenario is generally one of those prepared, although attention has focused on 1-in-5 and 1-in-10 peak weather in recent years.

After discussion at both the January 13 and February 9, 2005, workshops, participants seemed to agree that a reasonable threshold for considering adjustments was a 1% difference between the aggregated sum of the LSE load forecasts resulting from steps 1 and 2 and the CEC and/or CAISO reference load forecasts. To illustrate, after all adjustments based on individual LSE load forecasts were made, and if the sum of the adjusted load forecasts was greater than one percent different from the reference case forecast (itself adjusted as necessary to match RAR load forecasting conventions), then each individual LSE load forecast would be further adjusted proportionally so that the aggregate sum exactly matched the reference load forecast. Such pro-rata adjustments to all LSE load forecasts would be made only when the aggregate of LSE loads exceeds the reference CEC/CAISO load forecast by more than one percent. When this threshold is exceeded, two options were discussed:

- For the amount exceeding one percent, adjust all LSE load forecasts in a pro rata manner to make the resultant aggregation of modified load forecasts no more than one percent different

- Adjust all LSE load forecasts in a pro rata manner to exactly match the CEC/CAISO reference load forecast

Some parties asked whether if the CEC believes across-the-board pro-rata adjustments are needed, does it have the discretion to do this, or must the CEC inform the CPUC who will then formally decide to require an adjustment? This question appears to discount the suggested rule for imposing pro rata adjustments. If the Commission directs the use of such a rule, then it seems logical that the CEC would implement it.

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

6.C. Tabulation Of Qualifying Resources For Year Ahead Compliance Filings

The essence of the Year Ahead compliance filing is to demonstrate that sufficient resources have been acquired to satisfy the 90% forward commitment obligation for loads plus reserve requirements for each of the five summer months May - September. A quantitative tabulation of each resource that contributes qualifying capacity to meet loads plus reserves is needed for each month.

6.C.1. Tabulation Of Resources

Appendix I to this report provides a modified Working Proposal prepared by the CAISO. The original was discussed at the January 12, 2005 workshop and a revised version was discussed at the February 9 workshop. This modified version conforms to the revisions discussed at that workshop. In general the CAISO's proposal creates a set of reporting instructions and a template focusing on a display of resources, by category, for a specific peak load forecast for which a compliance demonstration is required. If the compliance obligation was simply a single peak hour for each month, then the CAISO's proposed template would be completed for each of the five summer months – May to September. Conceivably, if the "bottom-up" method were chosen then a series of loads describing the monthly load duration curve plus 15%-17% planning reserves would create a series of resource obligations for each month and the CAISO's template could be used for each of those load points. Alternatively, for this load duration curve approach, the CAISO's template could be turned into a matrix in which the differing contribution of a wide range of resources would be shown for each of the illustrative hours of each month.

While advisory staff's review of the Working Proposal is positive, staff have identified the following concerns that need to be resolved:

- The description of the process of review of LSE submissions in the "RAR Template" subsection presumes that the CAISO is the entity performing the reviews of the resource tabulation submissions. As noted in Section 3.A.2. of this report, which entities participate in review of Year-Ahead and Month-Ahead compliance filings still needs to be determined by the Commission.
- Whether the compliance materials are submitted in parallel to all reviewing entities or through the Commission to other entities participating in review may be affected by confidentiality arrangements and is not yet resolved.
- The proposed template and the instructions fail to identify DR programs that the LSE submits as part of the qualifying capacity to cover loads and reserves.
- The proposed template does not provide a means to designate a resource that satisfies local capacity requirements.

In addition to the basic spreadsheet template proposed by the CAISO, parties have expressed an interest in somehow diminishing reporting burdens. One approach mentioned at both the January 13 and February 9 workshops is to create a database that would compile the LSE's data, and then rather than requiring successive filings to repeat much of the same data over and over, to allow references to the previously filed and "vetted" data in the database. While this concept seems feasible, it would transfer some workload from the LSEs to the entity(s) performing the review process and require them to develop more sophisticated software to facilitate the LSE's goal.

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

6.C.2. Local Resource Adequacy Reporting Requirements

Section 5.J. discusses the requirements associated with local resource adequacy requirements. As noted there, parties have agreed that LSEs should make commitments for 100% of their local capacity requirements in load pockets on a year-ahead basis, and report the loads and resources in the Year-Ahead compliance filing. Unlike the non-local or "system" resource commitment demonstrations, local capacity requirements cover all twelve months of the year. Thus in the initial compliance filings for 2006, LSEs should report how they satisfy local capacity requirements for the months of June through December of 2006. In the compliance filings for 2007, expected to be submitted in the fall of 2006, LSEs should report how they satisfy local capacity requirements for all twelve months of 2007.

The format of the resource tabulation demonstrating compliance with the local capacity requirements should be integrated into the same format as described above for general resources covering total LSE load. Since these local capacity requirements also satisfy the LSE's general commitment obligations, it is important that the compliance filings and review integrate all resources together. Some sort of tag or columnar designation needs to be made for these resources so that the review process can identify them and sum across multiple LSEs serving load in a particular load pocket to verify that all necessary capacity has been committed to.

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

6.C.3. Confidentiality Issues

As a general rule, participants believe the same issues of confidentiality exist for qualifying capacity from resources as with load forecasts discussed in Section 4.A. above. Participants noted the following goals that various participants have, which are mutually incompatible:

- All LSEs wish to protect their data from any possible impact on their profitability or market position
- IOUs wish to see ESP data to be reassured that ESPs are covering loads with resources
- Non-Market Participant Parties wish to have access to data from all LSEs to ensure that no cost shifting is taking place and that reliability objectives are being met

Some participants were concerned that possible FERC approval issues might exist for resource tabulations because it involves use of information similar to that of the CAISO Participating Generator Agreement, and that if the CAISO is part of the review process that these concerns are magnified.

The Commission needs to determine what resource tabulation data should be held in confidence and for how long, and whether there should be access to such confidential data under appropriate protective order conditions.

6.D. Review Of Year-Ahead Compliance Filings

D.04-10-035 calls for a September 30 compliance filing each year for the "year-ahead" forward commitments for May-September of the following year.[44] LSEs are to use the final load forecast returned to them by the CEC as the basis for resource commitments that total to 90% of peak load plus 15%-17% planning reserves.

The basic goal of the year-ahead compliance filing review process is to confirm that all LSEs met their requirements and purchased qualifying capacity for each of the five summer months of the following year. In discussing review of compliance filings, parties developed the following list of activities:

[44] The Commission noted in D.04-10-035, page 13, that "…requiring compliance filings on September 30, 2005 may be problematic if issuance of the Phase 2 resource adequacy decision … is delayed beyond our current expectations. Therefore, for the first round of compliance filings made for May – September 2006, we provide that such filings are due on the later of September 30, 2005 or 90 days after the date of the Phase 2 decision."

1. Verify use of the “final” load forecast as issued by the CEC,
2. Ascertain that qualifying capacity rules applicable to the resources nominated for each month were followed,
3. Verify that the LSE used appropriate limitations on some categories of resources (e.g. limits on certain kinds of DR resources based on percentage of peak load or hourly load),
4. Verify that the resources are consistent with the CAISO’s qualified capacity listing which accounts for deliverability, generator performance, etc.,
5. Ensure that local capacity requirements were secured by resources within each load pocket, and
6. Determine that no double-counting of generator capacity by more than one LSE was submitted unless explicitly recognized and called out in documentation.

Appendix I to this report provides a Working Proposal prepared by the CAISO that spells out these general steps in more detail. The original was discussed at the January 12, 2005 workshop and a revised version was discussed at the February 9 workshop. This modified version conforms to the discussion held on February 9.

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

6.E. Interaction Between Month-Ahead and Year-Ahead Reporting Requirements

The October order required that 100% of the RAR must be met month ahead. The outstanding issue is how the month ahead report relates to the May –September requirement that 90% be committed a year ahead. Several workshop participants developed working proposals for the initial workshop on January 12, 2005. The CAISO and IEP submitted a “guidance” document that embodies the principles that they felt should guide compliance (see Appendix J). No party objected to the principles outlined in the proposals. The other working proposals were specific to the issues of what to report, who to report to, and when to report. Overall, many of the most difficult to resolve implementation issues stemmed from the LSE-only approach that was the premise of the initial workshop. Many of these issues are addressed by the proposal drafted by CPUC staff / CAISO proposal (see Section 2.A.1.) that splits the reporting and sanction obligations among generators and load.

6.E.1. Month-Ahead Reporting Timelines

There were two suggestions for when to report:

1. Month ahead, which would require LSEs to file mid-month of the month prior to compliance (April 15 for May 1), or
2. Last day of the second month prior to the compliance month (April 30 for June1)

Those in favor of option 1 argue that it would allow for economic opportunities that may occur closer to real-time. Those in favor of option 2 argue that 30 days is required for better enforcement, analysis of the submittals, and imposition of potential sanctions. The preferred approach with regard to timing was highly dependent on how closely the month-ahead and year-ahead reports are related. There was consensus that the level of detail in the month ahead report should factor into the amount of time needed to assess the report. Through the broader discussion regarding what is to be reported, most parties concluded that option 2 was preferable given the level of analysis that parties expect to be conducted after the report is submitted.

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

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

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

Edison suggests that if the LSE chooses to meet it full 100% peak load plus reserves in the year-ahead timeframe, there would be no additional reporting requirement in the month ahead. If the LSE fulfills its 90% year ahead, it would only be required to “fill in” the remaining 10% in the month-ahead filing. Under this proposal all the year-ahead filings would be carried over to the month ahead and there would be no opportunity to update load forecasts or updated assumptions of load migration affecting load forecasts with more recent information. This proposal has the limitation that unforeseen events affecting resources would not be incorporated into the month-ahead filing

ESPs maintain that the month-ahead filing should be an update of the year-ahead "check off" that allows LSEs to account for changes in loads. ESPs note that while additional direct access is not permitted, there can be considerable load shifting among ESPs.

Workshop participants agreed that the RAR is a planning requirement that has already incorporated load forecasts and supply acquisition in the Year-Ahead filing prior to the month-ahead. Month-ahead updates would be useful for accuracy and important for financial consequences to account for any load migration that may have occurred over the course of a year. TURN highlights that allowing for monthly updates to account for changes in load profiles is a practical outcome because making ESPs procure reserves for customers it no longer has is likely to be found unjust. Other participants highlighted that forecasts are established long in advance, but the allocation among LSEs can change as load migrates.

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

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

Workshop participants felt it was appropriate that LSEs report to both the CPUC and CAISO, despite the expectation that the CAISO is the principal entity with the resources and need to track Month-Ahead compliance.[45] To comply with the obligation, the LSE would show that they bought the required amount of capacity from the list of "qualifying capacity" maintained by the CAISO. This could be accomplished by the LSE providing a contract reference number or a generator ID. The LSE would make available the amount of capacity purchased and the capacity provider information (i.e. no price information) to the CAISO and

[45] The CAISO not only needs assurance that each LSE has acquired 100% of their forward commitment obligations, but also needs to know the specific resources that the LSE has nominated for that month.

CPUC. The reviewing entity would then verify that the LSE's filing satisfied all general and local capacity requirements.

To the extent that the Commission allows LSEs to update load forecasts to account for load migration or other factors, then these updated load forecasts will eventually have to be provided to the CEC for use in load forecast accuracy tracking activities. These activities are described in Chapter 4 of this chapter.

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

6.F. Compliance Tools: Level Of Sanctions On Load Serving Entities And Generators

There was general agreement among parties that sanctions should be onerous enough that they are not considered a "cost of doing business." Parties want opportunities to rectify simple filing mistakes and misinterpretations of rules. Workshop participants raised a number of compliance and penalty issues in the initial workshop when the working assumptions were that the obligation would be LSE-only and the LSE would therefore incur sanctions for supplier non-performance. This issue was one of the reasons LSEs felt the obligation was unfair and beyond their control. This issue was resolved by the CPUC staff / CAISO proposal discussed in Section 2.A.1. In general, LSEs are willing to be accountable for showing they have purchased the sufficient reserves to meet their RA requirement. LSEs are not willing to be accountable for the performance of the generators they contract with, believing that it is generators that must be responsible for satisfying availability and dispatch requirements.

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

Participants agreed that sanctions should be a multiple of replacement costs if a LSE fails to comply with its reserve requirement. Parties suggested that the sanctions should be set at a level that was fair, transparent, and easy to calculate. The workshop participants suggested a penalty equal to that three times the cost for new capacity as an appropriate penalty.

Inherent in the requirement of LSEs to meet resource adequacy based on monthly peak is the notion that the requirement varies throughout the year. Using monthly peaks can have the effect of forcing a large percentage of the fixed-cost recovery to occur during the higher summer peak months. Basing the LSE penalties on the same monthly variation throughout the year, could mean that penalties may need to be significantly higher in those few summer months. The suggested penalty of three times the cost for new capacity may require that the sanctions are imposed over more months (perhaps on an annual basis) than simply on a monthly basis to avoid the higher penalties during the summer months. *We ask parties to comment on the connection between the resource adequacy requirement time period and the time period used to impose penalties. The Commission will need to fully understand the appropriateness of imposing sanctions over a different timeframe than its required resource adequacy.*

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

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

As discussed in Chapter 2, the generator's obligation if it wants to be listed as a capacity resource would be established in the CAISO tariff. Under that obligation, the generator would be subject to CAISO penalties for non-performance such as uninstructed deviation penalties and de-rating in the next period as discussed above. Since the generator's obligation will be outlined in the CAISO's tariff, FERC will ultimately decide the sanctions for non-performance.

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

6.F.3. Administration Of Sanctions

It remains unresolved whether the CPUC or the CAISO should apply the sanctions for LSEs that do not perform. If the CPUC applied the sanctions it would have to:

1. Assess the compliance report quickly to determine if it is deficient or be informed of a deficiency by the CAISO;

2. Consider whether the CPUC can adopt up-front penalties that can be imposed without further proceedings (e.g. through delegation to Energy Division); and
3. Determine whether there are operational consequences if there is a procedural delay in assessing the report and imposing sanctions.

While clearly there is a jurisdictional element to whether the sanctions for non-compliance are administered by the CAISO, such an approach may have practical benefits to the extent that there are automatic, or more "real-time" provisions in the CAISO tariffs to impose sanctions quickly. In addition, in the event that a capacity market emerges, administration of RA compliance may be more consistent with facilitating that market.

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

6.G. After-The-Fact Review And Use Of Resource Adequacy Data In Other Forums

After-the-fact review was identified as a supplemental topic to the overall review process in a document distributed by advisory staff to all workshop participants in a December 20, 2004 email. It was discussed in parallel with other elements of the Year-Ahead review process identified as Topic 19 in the November 19, 2004 ALJ Ruling. It was discussed at both the January 13, 2005 and February 9 workshops. Broadly it consists of two elements:

1. comparison of load forecasts with actual loads, and
2. performance of resources nominated to satisfy forward commitment obligations and system support needs.

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

D.04-10-035 (p. 17) calls for determination of load forecast accuracy, which advisory staff interpret to mean the accuracy of LSE load forecasts put forward at either the Year-Ahead or Month-Ahead compliance filings compared to actual LSE loads. The history of this limited portion of D.04-10-035 suggests it came about due to concerns about LSEs "gaming" load forecasts, and a "monitoring" process should detect such behaviors.

LSEs asked whether the purpose of such review was merely informational, such as a diagnosis of the process or is there a regulatory consequence for individual LSEs if their load forecast accuracy is in some manner judged inadequate? If intended as “punitive” for specific LSEs, then some sort of benchmark of acceptable load forecasts would have to be developed, which has not yet been discussed. Some participants noted that implementing any sort of penalties tied to this review would be premature in the first cycle, especially since all of the “rules” may not be established yet when the LSEs have to submit load forecasts. Others noted that having penalties would be a basis for motivating improvements in load forecast accuracy, which appeared to be the intent of the CPUC. ESPs noted that they might be prepared to undertake at least some portion of this activity themselves, through an annual, self-funded audit as the CAISO requires for its settlement data submissions.

Key issues of load forecast accuracy assessments that were discussed, but not resolved, included:

- Which load forecast would be the one compared? As part of the Month-Ahead reporting requirements process, some participants have suggested that load forecasts should not be updated at the Month-Ahead filing, as a workload reduction effort. If load forecast accuracy standards and sanctions were introduced, then some parties might wish to update their load forecasts on a Month-Ahead basis so as to improve the performance of their load forecasts overall. Participants noted that LSEs should not be held accountable for CEC-directed load forecasts if these performed more poorly than the preliminary ones they submitted themselves.
- CAISO suggested the short-term CAISO load forecast mean error be used as the benchmark for judging accuracy, but other participants criticized this as an inappropriate standard for a “year-ahead” load forecast.

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

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

Resources nominated to satisfy resource adequacy must actually perform when called upon to ensure system reliability. Clearly, some monitoring of resource performance is an element of after-the-fact review. Because D.04-10-035, Section 3.8.2 creates a "if not scheduled then bid, and if not bid then RUCed" construct for resources, this can form the foundation for resource performance monitoring.

A resource not scheduled into the Day-Ahead scheduling process must bid into a Day Ahead market operated by the CAISO. Beginning in June 2006, the possible markets are the Day Ahead ancillary service markets. Once MRTU takes effect in February 2007, a Day Ahead energy market will substitute. The CAISO scheduling and bid data systems could be modified to track performance for resources nominated for resource adequacy.

A resource that did not have its bid accepted is still potentially on call to the CAISO if the RUC process determines that the unit will be necessary for reliability purposes. Again, existing CAISO data systems could be used to determine how each resource that should have responded to RUC operating room decisions actually performed.

The CAISO could take the two streams of tracking data discussed above and create a report for each LSE's package of resources nominated to satisfy its RAR. Such information should be provided to the CPUC as an element of an overall RA performance report and diagnostic tool. It is unclear whether such data should be reported back to each LSE or published for public review. While theoretically an entity other than the CAISO could also perform these assessments, this could only take place if a substantial amount of scheduling, bidding, and dispatch instruction data that is confidential according to CAISO tariff provisions were transferred to this entity. Thus, as a practical matter it may not be feasible for any entity other than the CAISO to perform these resource assessments.

At the February 8, 2005 workshop, a proposal was made that the performance of resources different than the average for its category to be recognized and in subsequent cycles the resource be allowed to have higher or lower qualifying capacity in recognition of its performance. This would create a resource specific performance incentive. This concept is recognized in D.04-10-035 under 2nd Generation topics. A standardized system for measuring performance, such as the NERC GADS data, would have to be established to obtain the baseline data for a financial incentive for performance. No specific proposal was put forward at the workshop, so this concept cannot be implemented at this time. It may be possible to accelerate this concept from 2nd generation to a "Phase 3" that would operate along the lines of the evolving resource adequacy process without waiting for the more complex elements that were also included as 2nd generation topics in D.04-10-035.

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

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

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

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

Participants discussed alternative timelines for a hypothetical after-the-fact review. Options included:

- Immediately upon completion of each day
- Following completion of each Month
- Following the May – September season

Parties generally seemed the support review following the May-September season, but inter-agency advisory staff does not believe this compatible with the “year round” nature of the RAR. There are load forecasts and actual loads for all twelve months. There are Month-Ahead forward commitment obligations for all twelve months and resource performance expectations for the qualifying capacity nominated by each LSE. Many parties believe that the May-September period is the most important due to high peak loads, but supply-demand imbalances can occur in any month.

In discussing who might conduct this review, parties noted that while the CAISO generally has a lot of this information as a result of the settlement process, that the CAISO would need some augmentation of the data they obtain to perform this analysis for each LSE. The CAISO generally gets actual load data through the settlement process, and it conducts settlements with scheduling coordinators, who are not necessarily LSEs. Only scheduling coordinators have schedules and actual load data for all LSEs.

Assuming that after-the-fact review were to be instituted, would there be public reporting, perhaps in aggregate masked form, about performance overall or for individual LSEs? The following questions are noted, but not resolved:

- Should reporting provide annual statistics alone or monthly statistics and results?
- What is the benefit to a public report of review results, including both load forecasting and resource performance?
- Is there value in reporting masked, individual LSE results beyond that gained by reporting aggregate results?

At least some portions of such a review process would be designed to provide the information required for performance standards, which if violated would lead to penalties and sanctions. In discussing how the information generated by such a review process might interface with a penalty structure, the following questions were raised without being resolved:

- Is the individual LSE information about overall performance public?
- Is the individual LSE information about alleged violations public?
- Is the individual LSE information about sanctions/penalties public once they have been levied by CPUC?
- Is aggregate information about violations of standards and penalties public?

The Commission must determine whether it wants to create an after-the-fact performance review process, and whether it wants this process to be informational or whether it wants ultimately this process to provide financial incentives to LSEs to forecast load more accurately and their nominated resources to perform at higher levels and respond more precisely to CAISO dispatch instructions.

6.G.4. Use Of Compliance Filing Data In CEC And CAISO Supply & Demand Assessments

At the January 13, 2005 workshop, participants noted that the CEC and CAISO have ongoing short-term supply/demand balance assessments that feed information to other agencies, governor and legislature.[46] The obvious question was raised, should the resource adequacy data submitted by LSEs be used in improving such short-term supply/demand assessments? Participants discussed several facets of this question, including:

- Parties were concerned that resource adequacy data and the CEC/CAISO analyses would have to be put on the same basis to ensure meaningful comparisons and to avoid mistaken impressions from naïve reviewers
- The effort to make these adjustments might be considerable, thus creating additional workload
- Summer 2006 discussions were known to be following other counting rules on the demand side, and this illustrates the challenge of making meaningful comparisons.

In answering the basic question of whether or how can this RAR compliance data be used in those processes, workshop participants expressed a strong preference that only aggregations of LSE submissions be used, rather than any mechanism that might reveal LSE-specific data.

The Commission must decide whether the resource tabulation data submitted by LSEs may be used by the CEC and/or CAISO in improving the short term supply/demand assessments that are used to inform the Governor and legislature, and if so, whether any aggregation constraints need to be imposed to assure that any individual LSE data confidentiality designations are protected.

[46] Calpine distributed such an assessment prepared by the CEC Staff for the December 2004 Energy Action Plan meeting at the February 9, 2005 workshop. It shows supply/demand balances on an aggregated basis for summer months and for future years, and includes alternative load forecasts based on alternative severity of peak weather.

APPENDIX A

Alliance for Retail Energy Markets
BAMx
California Manufacturers & Tech. Assn
California Independent System Operator
California Energy Commission
Calpine
California Wind Energy Association
Capstone
City & County of San Francisco
California Department of Water Resources
City of Redding
California Large Energy Consumers Association
California Municipal Utilities Association
Commerce Energy Group
Constellation Energy
Office of Ratepayer Advocates
Crested Butte Catalysts
Cummins Power Generation
Duke Energy
Dynegy Power Co.
Energy Management Services
Federal Energy Regulatory Commission
FPL Energy
Goldman Sachs
Independent Energy Producers
Imperial Irrigation District
Mirant
Morgan Stanley Capital Group
Northern California Power Authority
NRG Energy
Pacific Gas & Electric
Platts
Powerex Corp
PPL EnergyPlus
PPMEnergy
Reliant Energy
Southern California Edison
San Diego Gas & Electric
Sempra Energy Solutions
Sempra Global Energy
Strategic Energy
Silicon Valley Manufacturers Group
SWC
The Utility Reform Network
Williams
Western Power Trading Forum
Xcel Energy Marketing

(END OF APPENDIX A)

APPENDIX B

Standalone Resource Adequacy Capacity Product

I Purpose:

A capacity product, or "tag," acceptable to the PUC that could (among other things) meet the CPUC resource adequacy requirement as a standalone product.

II Essential Elements:

1. Buyer can count Capacity towards Resource Adequacy
2. Seller owns or controls Capacity
3. Capacity is "qualified." (qualifying criteria based on CPUC-established counting protocols and on Contract Quantity being "deliverable" as determined in the RAR deliverability process)
4. Capacity is not double-counted, e.g., in any unit-specified contract also used to satisfy resource adequacy requirements.
5. Seller has an "availability" obligation – an obligation to make the Contract Quantity available to the CAISO for all hours of every day of the Delivery Period. Prior to the implementation of MRTU, to meet this availability obligation, the Seller must meet one of the following requirements with respect to the Contract Quantity unless the Contract Quantity is unavailable due to a declared forced outage or a planned outage that has been approved by the CAISO:
    a. Scheduled for energy delivery to load within the CAISO control area.
    b. Scheduled to provide day-ahead ancillary services.
    c. Must-Offer Wavier requested from CAISO in accordance with CAISO tariff, and
        i. If Must-Offer Waiver is granted by CAISO,
            1. if Specified Resources are comprised of units other than short-start units, Seller is under no further obligation to make Contract Quantity available to CAISO during waiver period.
            2. if Specified Resources are comprised of units with startup times under 5 hours (short-start units), Seller must make Contract Quantity available to the CAISO on a same-day must-offer basis subject to the start time of the unit(s).
        ii. If Must-Offer Waiver is denied by CAISO,
            1. Seller must make Contract Quantity available in CAISO's real-time markets, and Seller would be eligible for startup and minimum load payments in accordance with CAISO tariff.

    The following requirements would apply if the CAISO chooses to commit resources designated for resource adequacy based on their bids in the Ancillary Services market rather than through the Must-Offer Waiver Denial Process:

    d. Bids submitted into CAISO day-ahead ancillary services market for all 24 hours of the operating day, and,
        i. if not cleared in the day-ahead ancillary services market, Seller is under no further obligation to make Contract Quantity available to CAISO for that operating day; or,
        ii. if cleared in the CAISO day-ahead ancillary services market, Contract Quantity operated in accordance with CAISO tariff; and

iii. if Contract Quantity is committed but not fully scheduled in the day-ahead timeframe, bids submitted into CAISO hour-ahead ancillary services or supplemental energy markets in “real time” for all hours, and Contract Quantity operated in accordance with CAISO tariff.

If Specified Resources underlying Contract Quantity include units designated as “Energy Limited Resources” Seller will notify CAISO of such designation and total available hours for commitment. CAISO will flag Energy Limited Resources and dispatch them out of market only if needed to maintain grid reliability and only up to the total available hours.

This availability obligation precludes submission of firm “Wheeling Out” and Wheeling Through” schedules.

III Other Matters:

A Transaction with this product constitutes the sale of a Contract Quantity (in MW) of Capacity that the Buyer may count toward Buyer’s resource adequacy obligations during the Delivery Period, and which Seller supplies from Specified Resources that are qualified and screened for deliverability for the Delivery Period.

Buyer purchases only the right to count Capacity toward Buyer’s resource adequacy obligation during the Delivery Period. Energy and ancillary services from the Specified Resources may be sold to others during the Delivery Period subject to the Seller’s availability obligation hereunder.

“Specified Resources” refers to a portfolio or list of Seller’s individual units that comprise a certain amount of certified or qualified capacity for purposes of resource adequacy and have specified deliverability. Note that while Specified Resources may refer to a portfolio of units on a year-ahead or month-ahead basis, schedules or bids pursuant to the Seller’s availability commitment identify individual units on a day-ahead basis.

“Delivery Period” refers to the period (months) during which the Buyer can count the Contract Quantity toward Buyer’s resource adequacy requirements and during which Seller has an obligation to make the Contract Quantity available to the CAISO.

The term “delivery region” is a placeholder for any specific areas or locations established by the PUC for purposes of resource adequacy.

The Capacity Product should rely on the PUC’s established mechanisms for qualifying and counting capacity. (i.e. agreed upon counting protocols).

Seller’s obligation to take all commercially-reasonable actions to maintain the availability of the Specified Resources is limited but includes any obligations included in the PUC’s counting protocols.

The Capacity Product does not specify or restrict Seller's bid price into any market administered by the CAISO; however, all bids are governed by the CAISO's FERC-approved Tariff.

IV RA Capacity Availability Commitment and Existing (pre-MRTU) Must Offer Waiver Denial Process

Based on previous direction from FERC, the availability obligation on resource adequacy units described here would replace the existing Must Offer Obligation in the CAISO tariff prior to the implementation of MRTU. Accordingly, only units designated for resource adequacy and subject to the availability obligation described herein would be subject to the existing Must Offer Obligation, and units not under contract to provide Capacity as described herein would not be subject to the Must-Offer Obligation. We note that if during the initial implementation of resource adequacy units essential to local grid reliability remain uncommitted under Capacity contracts even after the imposition of local resource adequacy requirements, the ISO has the ability to place these units under RMR contracts during the period between the resource adequacy compliance showing and the Delivery Period.

V RA Capacity Contract Language

An illustrative example of contract language containing these elements for Capacity connected to the CAISO-controlled grid follows. While we did not have the opportunity to complete the discussion on contract language for imports or units not connected to the CAISO-controlled grid, contract language for such resources that are "tagged" as Capacity to meet a Buyer's resource adequacy requirement would include all of the same essential elements noted above, but with analogous provisions to satisfy CPUC qualification and deliverability requirements and the Seller's availability obligation. Specifically, imports would be qualified and screened for delivery based on a showing that the Contract Quantity:

(a) is an import energy product with operating reserves; that
(b) it cannot be curtailed for economic reasons; and that
(c) it either
    (i) is delivered on transmission that cannot be curtailed in operating hours for economic reasons or bumped by higher-priority transmission, or
    (ii) specifies a firm delivery point (not seller's choice).

Seller's availability obligation would consist of requirements to schedule or offer the Contract Quantity as bids or schedules at the predetermined Inter-tie Scheduling Point for all hours of every day of the Delivery Period, first on a day-ahead basis, then on an hour-ahead basis if the Contract Quantity does not clear day-ahead, according to existing processes in the CAISO tariff.

Illustrative Capacity Product Contract Language

1. Definition

1.1 "Forward Commitment Obligation Capacity" or "FCO Capacity" or "Capacity" means the qualified and deliverable capacity from Specified Resources that can be counted toward Buyer's forward commitment obligations for resource adequacy requirements as described in D.04-10-035, and as may be amended from time to time by the California Public Utilities Commission ("PUC") or other regional entity responsible for resource adequacy requirements.

1.2 FCO Capacity does not confer to Buyer any right to the Contract Quantity of Seller's Specified Resources other than the right to count such Contract Quantity toward Buyer's Forward Commitment Obligations during the Delivery Period.

2. Seller Representation and Warranties:

2.1 For Capacity located within the CAISO Control Area or connected to the CAISO Controlled Grid: Seller represents and warrants to Buyer that Seller has ownership of or demonstrable exclusive right to the Specified Resources supporting Seller's Contract Quantity obligations under the Transaction, and that such resources are located in [delivery region].

2.2 Seller commits to Buyer the right to count the Contract Quantity from Specified Resources toward the Forward Commitment Obligations of Buyer's resource adequacy requirements during the Delivery Period.

2.3 The Parties shall take all commercially reasonable actions and execute all documents or instruments reasonably necessary to effect the use of the Contract Quantity for the sole benefit of Buyer's Forward Commitment Obligations toward satisfaction of its resource adequacy requirements during the Delivery Period. Such commercially reasonable actions shall include:

(i) Cooperating with and encouraging the regional entity responsible for resource adequacy administration to certify or qualify the Contract Quantity for resource adequacy purposes. This includes meeting requirements established by the PUC in its resource adequacy counting protocols, including demonstration of the ability to deliver the Contract Quantity over the "90% hours" required for resource adequacy, and either demonstrating that the Contract Quantity can be delivered to the CAISO Controlled Grid, pursuant to "deliverability" standards established by the PUC or regional entity responsible for resource adequacy administration; [This is included to the extent deliverability is assessed after qualified capacity];

(ii) For Specified Resources located within the CAISO Control Area or connected to the CAISO Controlled Grid, that the Contract Quantity can be delivered to the CAISO Controlled Grid under a Participating Generator Agreement, or Qualifying Facility Participating Generator Agreement [be aware that this may not fly because most QFs do not have any formal agreement or obligation to the ISO];

(iii) negotiating in good faith to make necessary amendments to this Confirmation, if any, including amendments necessary to conform this Confirmation to subsequent clarifications, revisions or decisions rendered by the PUC or regional entity responsible for resource adequacy administration; and

(iv) use of "Good Utility Practice," as defined in the CAISO Tariff, with respect to maintenance of Specified Resources; however, such commercially reasonable actions shall not include any obligation that the Seller undertake capital improvements, facility enhancements, or the construction of new facilities. Furthermore, Seller represents and warrants to Buyer that Seller:

a. has not committed, and shall not commit, any portion of the Contract Quantity to satisfy the Forward Commitment Obligations, or analogous obligations in other markets, of any party other than Buyer during the Delivery Period;
b. shall not schedule any portion of the Contract Quantity as firm (non-recallable) energy outside the CAISO control area until all obligations to offer the Contract Quantity to the CAISO hereunder have expired and are uncalled by the CAISO;
c. has not committed and shall not commit any portion of the Contract Quantity to any third party in a manner that would result in the scheduling of the Contract Quantity as firm (non-recallable) energy outside the CAISO control area until all obligations to offer the Contract Quantity to the CAISO hereunder have expired and are uncalled by the CAISO;
d. shall make the Contract Quantity available to the CAISO for all hours of every day of the Delivery Period. To satisfy this obligation, Seller must meet one of the following requirements with respect to the Contract Quantity unless the Contract Quantity is unavailable due to a declared forced outage or a planned outage approved by the CAISO:
    1. Scheduled for energy delivery to load within the CAISO control area.
    2. Scheduled to provide day-ahead ancillary services.
    3. Bids submitted into CAISO day-ahead ancillary services market for all 24 hours of the operating day and if cleared in the CAISO day-ahead ancillary services market, Contract Quantity operated in accordance with CAISO tariff.
e. shall notify CAISO if Specified Resources includes units designated as “Energy Limited Resources” and the total available hours for commitment. Buyer and Seller expect that CAISO will flag Energy Limited Resources and commit them for energy dispatch out of market only if needed to maintain grid reliability, and never beyond the total available hours; and
f. shall not submit firm “Wheeling Out” and “Wheeling Through” schedules for the Contract Quantity; and
g. shall abide by all applicable CAISO rules and procedures approved by the FERC.

(END OF APPENDIX B)

APPENDIX C

Phase 2 Resource Adequacy Report On

The Quantification and Allocation of Energy Efficiency and Demand Response

Prepared By The Topic 3/4 Working Group[47]

January 14, 2004 DRAFT

1. Summary of The Working Group Recommendations

This report presents the recommendations of a group of parties (Working Group or WG) participating in the CPUC's Phase 2 resource adequacy (RA) workshops regarding the quantification and allocation of energy efficiencies (EE) and demand response (DR) impacts for purposes of load serving entities (LSEs) meeting the CPUC's RA requirements.

Regarding the allocation of the EE/DR impacts, the WG recommends that for RA purposes the impacts associated with the utilities' EE/DR programs be allocated to the LSEs in fixed proportion using metrics that are transparent, equitable, and relatively simple to quantify and apply.

In principle, the EE/DR impact should be allocated to the LSEs in proportion to the funding their respective customers provide toward the utilities EE/DR programs. In order to simplify the allocation process, as a proxy for their funding contribution, the WG recommends allocating the impacts in proportion to the LSEs energy sales, as follows:

- For EE programs, the WG recommends using the percentage of total IOU retail sales (i.e., bundled plus DA) represented by incremental EE savings for each utility to determine an LSE's share of that utility's incremental EE impact. [Question: For RA purposes, shouldn't we be more concerned with how to allocate the qualifying capacity of the EE programs? If that is the case, then we will first determine the qualifying capacity of the EE programs, and then allocate that impact in proportion to the LSE's sales, in the same way DR impact is allocated?
- For DR programs, as a proxy for funding the WG recommends using the percentage of each LSE's sales to the sum of all LSEs' sales within a utility's service area to allocate that utility's DR impact. Because an LSE's funding contribution to a utility's DR programs can vary by program (at least in the case of the CPA program

[47] List of Working Group members is included as Attachment 1.

now administered by PG&E), the allocation percentages for DR impacts can vary by program. [48]

This report provides estimated allocation percentages for the existing utility EE/DR programs by utility. The WG recommends that the utilities determine the EE/DR RA impacts and allocation percentages annually.

Regarding the quantification of the EE/DR impacts, the WG recommends that parties continue using their present methodologies, and review and evaluate those methodologies based on the results from measurement and evaluation (M&E) efforts currently planned for next year in R. 01-08-028 (in particular the December 30, 2004 ALJ ruling) for EE, and R. 02-06-001 for DR. The report explains the methodologies presently used by the utilities and their pros/cons. The remainder of this report provides additional information about the above recommendations, remaining areas of disagreement, and answers to questions raised by parties at the November 30, 2004 workshop where these two topics were initially discussed.

2. Allocation of the EE/DR impacts

a. Parties initial proposals

At the November 30 workshop, PG&E and SCE presented competing alternatives for allocating the EE/DR impacts.

(1) SCE's proposal

SCE proposed to allocate forecasted incremental EE impacts[49] to all LSEs based on a uniform percentage. Specifically, SCE recommended using the percentage of total IOU retail sales (i.e., bundled plus DA) represented by system energy efficiency savings, which in SCE's case equals approximately 0.3%, applied to the total energy sales of each LSE. In other words, all LSEs assume incremental energy efficiency savings equal to 0.3% of their kWh sales. SCE's estimate of 0.3% was based on a preliminary analysis using 2002 program data, and reflects the results of all PGC-funded EE programs. A more current analysis reflecting procurement-funded, i.e., incremental EE is provided below.

[48] Note that the utilities are verifying that the kWh sales allocation for DR impacts is a good proxy for funding-based allocation.

[49] Incremental EE impacts are energy savings associated with EE investments over and above committed (i.e., Commission approved) levels of EE funding. Since energy savings associated with past levels of EE funding are already reflected in all LSEs' load forecast, the relevant EE allocation is for incremental load changes associated with incremental changes in EE funding.

Year	Total Retail Sales (GWh)	Total EE (GWh)*	EE as % of System Sales	Incremental EE (GWh)	Incremental EE % of System Sales
2004	82,193	777	0.95%	469	0.57%
2005	83,964	777	0.93%	469	0.56%
2006	85,200	922	1.08%	602	0.71%
2007	86,600	1,046	1.21%	726	0.84%
2008	88,400	1,167	1.32%	847	0.96%

*2004-2005 reflects programs approved in D.03-12-060 and subsequent decisions;
2006-2008 reflects goals approved in D.04-09-060

For the years 2006 to 2008 SCE's incremental EE averages approximately 0.83 percent of total system sales.

For DR, SCE also proposed to allocate forecasted DR impacts to all LSEs based on a uniform percentage. SCE proposed using the percentage of system peak demand represented by demand response impacts, which equals approximately 3.5%, applied to the annual peak demand of each LSE. That is, all LSEs assume demand response reductions equal to 3.5% of their annual peak demand.

(2) PG&E's proposal

Similar to SCE, PG&E proposed to allocate the forecasted incremental EE impact associated with mass-marketed programs, based on the LSEs' relative forecast load. However, for large projects, which utilities or LSEs could track individually, PG&E proposed to allocate their impact based on prospective accomplished savings by customer. To implement, the utility would need to track the project, and supplement the necessary information for the LSEs to adjust their hourly load forecast. The information needed includes: customer identification, projected savings (hourly kW impact), and the peak time when savings will be realized.

For DR, PG&E proposed that DR impacts should be counted only by the LSE sponsoring the DR program.

(3) December 16 WG conference call

Following the workshop, the WG held a conference call on December 16 to review their positions and, address questions or issues raised by parties at the November 30 workshop. Answers to major issues and questions are addressed below in Section 2.b of this report.

b. Updated proposals

(1) EE impact allocation

During the December 16 call, the complexity with implementing customer-specific tracking of EE impacts for large projects as PG&E had proposed was considered. No call participant supported the explicit allocation of large projects as PG&E had originally proposed. Given the additional complexity and cost such an allocation might require, PG&E now supports SCE's approach to allocate incremental EE impacts prorata among all LSEs.

In summary, the utilities propose to allocate EE impacts to all LSEs based on the ratio between the utility's estimated incremental energy (i.e., kWh) efficiency savings and its kWh sales (bundled, DA and future community choice aggregated or CCA sales). The resulting allocation percentages are shown in Table 1.

Table 1
Allocation Percentages Proposed for EE Incremental Impacts

Utility	Allocation %	Variables used to calculate percentages
PG&E	0.4%	Percentage of utility energy sales represented by incremental system energy efficiency savings
SCE	0.8%	
SDG&E	TBD	(Based on forecasted data)

(2) DR impact allocation

WG parties agree that the DR impact should be allocated to all LSEs in proportion to the funding their customers provide to the specific utility programs.

At the November 30 workshop, PG&E showed an example illustrating how the DR impacts are counted via SC-to-SC trades in the ISO markets. (The example is Attachment 2 to this report.) In those markets, only the LSE sponsoring the DR program can receive credit for the DR. Based on the treatment of DR impacts in the ISO markets, PG&E proposed at the November 30 workshop that the DR impact be counted only by the LSE sponsoring the DR program. However, at the December 16 conference call, it became clear that the allocation of RA credit to LSEs can be handled separately from the allocation of energy in the ISO's day-ahead or real-time markets, preserving the initial principle that the DR impact for RA purposes should be allocated to all LSEs in proportion to the funding their customers provide.

Funding can vary from DR program to DR program, as some costs are recovered through memorandum/balancing accounts (i.e., Advanced Metering and Demand Response Account (AMDRA) in PG&E's case, etc.) or some may be directly recovered through rates. However, the basic and typical method of recovery of costs is through utility rates, in which both bundled and DA customers contribute through their revenues paid for utility electric service. Thus, the DR impacts should be allocated to all LSEs in proportion to the funding their customers provided to the specific program. For example, since DA customers participate in the non-firm program, and program costs are included in rates, DA customers would get a share of the non-firm impacts based on the percentage of DA funding contributed compared to all other utility funding received.

Ideally the allocation should be directly based on the funding provided by each customer group. However, in the absence of these funding data it may be reasonable to apply kWh usage as a proxy for funding data, since DR costs are ultimately recovered through rates. However, the validity of this proxy approach remains to be verified. Because the costs of DR programs are not allocated uniformly based on kWh sales, this proxy approach by yield inappropriate allocations and, thus may not be viable. Further analysis is required. Table 2a provides an illustrative example of how the allocation percentages can be calculated using a kWh proxy.

TABLE 2a. Illustrative Example of Allocation of DR Impact to LSEs

Assumptions:

DR Program Impact: 500MW

Customer Group	**12-month Usage (kwh)**	**% of System**
CCA	10,000,000	5%
DA	20,000,000	10%
Bundled (non-CCA and non-DA)	170,000,000	85%
Total System	200,000,000	
	DR Impact Allocation (MW)	**% of System**
CCA	25	5%
DA	50	10%
Bundled	425	85%

Thus, based on the illustrative example above, the DA LSE will receive 10% of the DR programs impact or 50 MW. In order to keep things simple, and allow for proper planning and forecasting, the proposal is to do this calculation and allocation once a year, and the same percentage will be used for twelve months. Table 2b shows each utility’s proposed percentage calculations for the DR impacts.

Table 2b
Current Allocation Percentages Proposed for DR Impacts

Utility	Allocation %	Variables used to calculate percentages
PG&E		Both CPA DR and DR allocations will be determined by the respective LSEs contribution to the program.
• CPA DR	TBD	
• Other DR		
SCE		
• CPA DR	TBD	
• Other DR	TBD	
SDG&E		
• CPA DR		
• Other DR	TBD	

3. Quantification of EE/DR impacts

a. Parties proposals

At the November 30 workshop, PG&E and SCE also presented proposals for quantifying the EE/DR impacts.

(1) SCE's proposal

At the 11/30/04 workshop SCE proposed to quantify the EE impact for RA purposes based on existing studies and studies in progress to estimate available EE peak and DR impacts. SCE believes that data do not currently exist to forecast accurately at an 8,760 level of detail, and proposed to use the current time-of-use approach until adequate M&E data become available through current and upcoming studies.[50] In the meantime, SCE advocated reporting EE/DR results using peak hour impacts only or day-type impacts (e.g., 25 day-types or 36 day-types).

Based on the results of the 12/16/04 conference call and additional analysis, SCE is willing to provide conditional support for reporting forecasted savings on an 8,760 basis. However, in offering this support SCE is attempting to inform all parties about the risk of assuming a false level of precision, which is inherent in providing data at such a detailed level. SCE develops its EE forecast based on five

[50] Energy efficiency impact studies for the 2004/5 programs seek ways to achieve better peak measurement. The Commission is determining responsibility for impact studies for programs after 2005.

time-of-use (TOU) periods (summer on/off/mid peak and winter off/mid peak). To convert its TOU forecast results into 8,760 hourly impacts SCE first uses an algorithm to translate the TOU results into a 25 day-type format. The 25 day-types consist of two day-types (weekday and weekend day) for each month (24 day-types) plus one peak day daytype. The 25 day-type results are then translated into 8,760 format using another set of algorithms. Although the algorithms used by SCE are reasonable and consistent with industry practice, the "spreading" of forecasted EE impacts based on five TOU periods to 8,760 hours yields a level of false precision that should not be mistaken to be a true measurement of the EE impacts within each of the 8,760 hours. Parties should be attentive to the possibility of drawing erroneous conclusions based on how the forecasted TOU impacts are spread to 8,760 hours.

(2) PG&E's proposal

PG&E proposes to estimate the EE and DR impact for RA purposes based on past historical impact of similar programs. For EE, PG&E currently relies on end-use data to estimate hourly impacts, and from those develop peak impacts. PG&E will also incorporate any findings from M&E work planned for the first part of 2005 in R. 01-08-028 into its current methodology.

For new DR programs, R.02-06-001 requires that demand response programs proposed in that proceeding be measured and evaluated. An initial M&E report from that was issued in December 2004. As part of this measurement process, expected ranges of demand response based on customer peak demand, market price, and temperature will need to be developed for each program. Much of this information isn't available because a long history of DR operations hasn't yet been established. However, once established, participation rates and expected demand reductions for the various planning scenarios will be available for estimation. For example, PG&E proposes to evaluate DR participants' peak demands and load shapes. The hourly data from historical participant's operations will be used to determine future program rollouts and forecast impacts. The participants' responses to various triggers and financial considerations will also be evaluated. These DR estimates will then be overlayed with the "counting" rules established in this proceeding to come up with appropriate figures for the RA forecasts.

In summary, the WG recommends that parties continue using their present methodologies, and review and evaluate their methodologies based on the results from measurement and evaluation (M&E) efforts currently planned in R. 01-08-028 for EE, and R. 02-06-001 for DR.

4. Answers to questions from the November 30 workshop

The following addresses questions raised by parties at the November 30 workshop.

Q1. What program impacts are included in load forecasts through use of historic data and econometric techniques for load forecasting, versus what impacts are not so included?

A: The utilities' econometrically-based load forecast models incorporate projected reductions in load due to past, and existing conservation programs. In addition, the utilities need to account for the effect of incremental changes to those historical EE funding levels. As a result, the utilities subtract the effect of those incremental EE investments from the model-forecasted load.

Q2. What about LSEs using other LF techniques?

A: It is unlikely that a "one size fits all" formula or model can be used to estimate the incremental effect of EE (whether funded through utility rates or not) since the formula or model will need account for past EE investment done by that LSE and the expected savings of those investments. It is clearly the responsibility of each LSE to forecast and demonstrate the projected EE savings of its EE programs.

Q3. Are customers participating in EE and DR programs tracked by LSE of the customer? Can this be done for large customers? Can non-IOU LSEs get such information about their customers? Can the CEC get this information for verification and/or adjustment of LSE load forecasts?

A: PG&E no longer proposes to allocate the impact of large EE programs by customer, and agrees to allocate to all LSEs the impact of its incremental EE savings proportionally as described above. Regarding other entities' access to customer information, to protect customers' right to the confidentiality of their information, non-IOU entities can be provided information about individual customer participation in EE and DR programs only with the customer's written consent.

Q4. What are the source of funding of existing interruptible/non-firm and other DR programs?

A: Funding for existing interruptible/non-firm DR programs is done thru T/D rates.

Q5. Identify source of data for determining rollout of programs and effective date of impacts by calendar month for 2006 incremental impacts

A: The Commission has not yet decided the entity which will administer energy efficiency programs for 2006 and after. According to the recently released proposed decision, a program proposal would be due to the Commission in early June. Monthly projections for the period May through September 2006 could be developed by mid-August, 2005.

Q6. Describe the methodology that PG&E proposes to use to determine the hourly profile for CEE essentially mapping measures to end-uses and using end-use load shapes

A: The methodology PG&E has used is to:

1. Group energy efficiency program activities into major end-use categories,
2. Allocate annual energy savings into hours using the load shape of that end-use category, and
3. Determine appropriate peak impacts base on the hourly impacts ("peak" is defined differently in different contexts – using a common set of hourly impacts yields consistent values for "peak" in different context.

To account for the occurrence of energy efficiency savings over the year, the annual targets for 2006 (and possibly the accomplishments occurring in 2005) will need to be attributed to the months in which the savings are expected to occur.

Q7. Describe the SCE method of using day types and mapping from them to highest load hours per month.

A: As described above, SCE is willing to conditionally support reporting forecasted savings on an 8,760 basis.

Attachment 1 – Working Group Members

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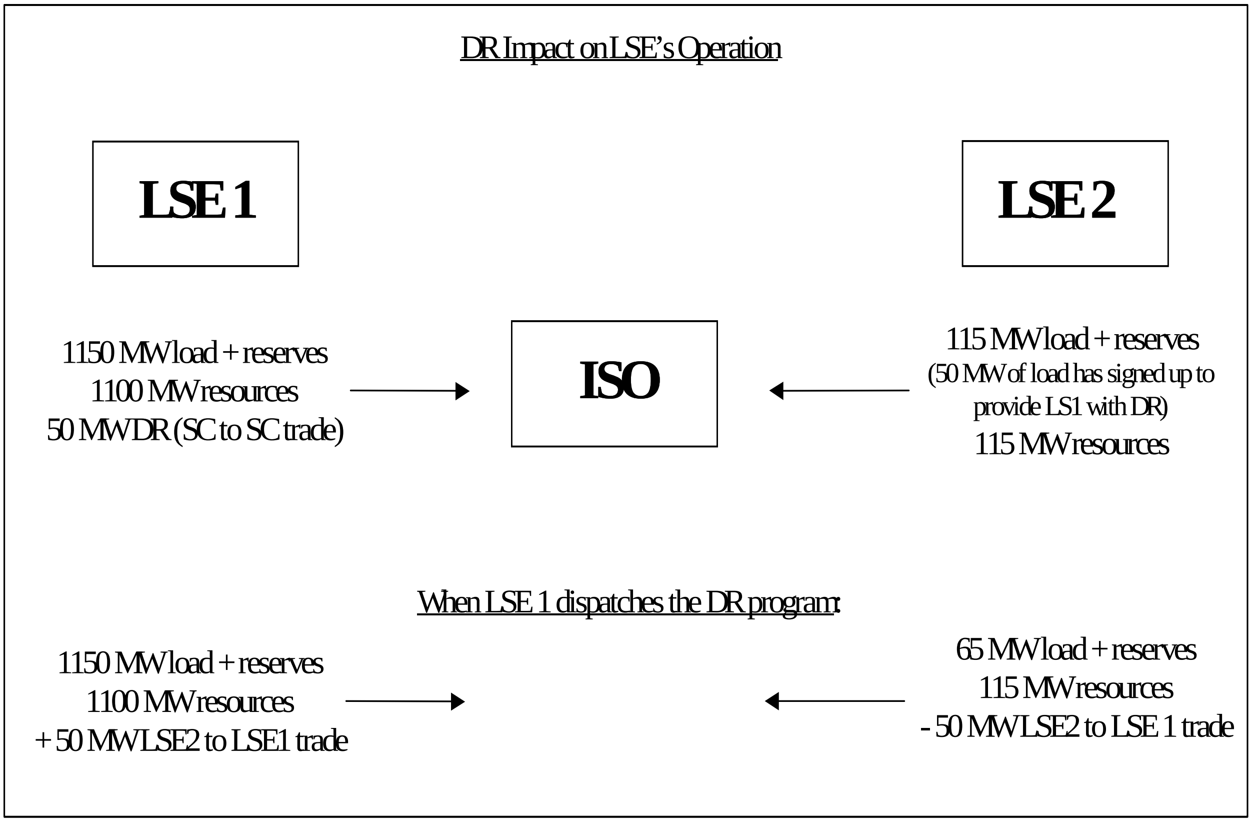
Attachment 2- Example of DR impact allocation in ISO markets



(END OF APPENDIX C)

APPENDIX D

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

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

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

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

Deliverability Of Generation To The Aggregate Of Load

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

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

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

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

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

B. Deliverability of Imports

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

The ability to rely on imports to satisfy reserve requirements is entirely dependent on the *deliverability* of such out-of-state resources to and from the intertie points between the

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

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

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

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

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

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

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

D. Summary

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

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

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

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

Section I
Generator Deliverability Assessment

1.0 Introduction

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

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

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

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

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

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

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

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

The procedure proposed for testing generator deliverability follows.

2.0 Study Objectives

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

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

3.0 Baseline analysis

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

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

4.0 General Procedures and Assumptions

Step 1: Build an initial powerflow base case modeling ISO resources as shown in Table 1. This base case will be used for two purposes: (1) it will be analyzed using a DC transfer capability/contingency analysis tool to screen for potential deliverability problems, (2) it will be used to verify the problems identified during the screening test, using an AC power flow analysis tool. All new generation applicants in the interconnection queue ahead of the unit under study are set at 0 MW (but available to be turned on for the screening analysis but not for the AC power flow analysis). Unused Existing Transmission Contracts (ETC's) crossing control area boundaries will also be modeled as zero MW injections at the tie point, but available to be turned on at remaining contract amounts for screening analysis. Then the capacity resource units in the queue electrically closest to the unit being studied are turned on at 90% of Dependable Capacity until the net ISO Control Area interchange equals the interchange target (see deliverability of imports section). Generation applicants after the queue position under study are not modeled in the analysis.

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

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

The outputs of capacity units in the 5% circle are increased starting with units with the largest impact on the transmission facility. No more than twenty[51] *units are increased to their maximum output. In addition, no more than 1500 MW of generation is increased. All remaining generation within the Control Area is proportionally displaced, to maintain a load and resource balance. The number of units to be increased within a local area is limited because the likelihood of all of the units within a local area being available at the same time becomes smaller as the number of units in the local area increases. The amount of generation increased also needs to be limited because decreasing the remaining generation can cause problems that are more closely related to a deficiency in local generation rather than a generation deliverability problem.*

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

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

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

Table 1: Resource Dispatch Assumptions

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

* The initial baseline analysis would identify the initial set of Certified Capacity Resources and Energy Resources. See section 3.0 Baseline analysis.
** Summer peak load hours are the 50 to 100 hours in the months of August and September when Control Area load is between 90% and 100% of maximum annual load.

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

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

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

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

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

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

Section II
Deliverability of Imports Assessment

Background

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

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

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

Because of the need for up-front information the ALJ assigned the ISO to lead a smaller group of Workshop participants to develop a methodology for determining the total amount of import capacity, by import path, which could be available to LSEs.[52] This document describes a proposal for a methodology developed by the subgroup.

Discussion of Proposed Approach

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

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

expense of more internal generation being available to meet an LSE's resource adequacy requirement.

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

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

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

Proposed Methodology

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

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

<u>Deliverability Priority</u>
If the baseline deliverability analysis for existing generation determines that the initial import level assumption is reducing the deliverability of internal ISO grid generation, then the initial import levels will be reduced and the baseline deliverability analysis will be re-run. Although it is not anticipated that import levels will have to be reduced significantly from their initial level, this issue may need to be reassessed after the analysis is completed, consistent with the "Review of Results" paragraph (below.)

Make Results of Deliverability Assessment Available for Use
Once the deliverability assessment is completed the results will be provided for use in developing year-ahead LSE resource procurement plans for resource adequacy purposes.[53] The total import capacity, by path, determined to be deliverable would need to be allocated to LSEs using some allocation methodology that has yet to be defined.

(Optional Step) Modify Results of Deliverability Assessment based on Economic Tradeoff between Import Capacity and Internal Generation Capacity

This step assumes that the deliverability of existing resources may not necessarily be preserved, and could be reduced as needed to increase the deliverability of imports, if it is determined that more economic capacity can be obtained from import levels that exceed the total import capability allocated to LSEs. Some sub-group participants had concerns regarding the logistics of implementing this step, and there is no consensus whether or not this step should be included in this general methodology.

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

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

Timeline for Initial Generation Deliverability and Import Deliverability Assessment

Timeline	Description	Responsible
Nov 16-Dec 14 2004	Develop baseline Total Import Capacity	ISO
Nov 16-Dec 14 2004	Develop PTO network models	PTOs, generation owners
Dec 15, 2004- Jan 18, 2005	Aggregate network models	ISO
Dec 15, 2004- Jan 18, 2005	Develop contingency files, including description of operations of all remedial action schemes and special protection schemes	PTOs
Jan 19-Jan 25, 2005	Stakeholders review basecases	All
Jan 26- Feb 1, 2005	ISO incorporates stakeholder comments into the basecases	ISO
Feb 2-March 29, 2005	Perform preliminary generation deliverability baseline analysis to establish deliverability of existing generation units and imports. Baseline total import capability would be an input assumption for this analysis but could be adjusted according to the proposed reduction priority. ISO would provide results of analysis to stakeholders.	ISO
March 30-April 12, 2005	Stakeholder review preliminary results. If based on stakeholder review, adjustments are proposed to the methodology, these adjustments would be discussed at this time.	All
April 13-May 31, 2005	Deliverability analysis would be completed including any adjustments to the methodology determined to be necessary during stakeholder review.	ISO
June 1-June 7, 2005	Provide Results	

Generation and Import Baseline Deliverability Study
Initial Data Requirements

1. Information from generation resources, whether LSE controlled or merchant: Net Dependable Capacity during Summer Peak load conditions and Qualified Capacity during Summer Peak load conditions as defined in the Resource Adequacy Workshop Report for each and every unit in the ISO Control Area that will be commercially operable during summer 2006.

    Responsibility: Initial responsibility will be on LSEs to provide the requested information from all resources under contract or control, including QF resources. For those resources not under contract or the control of an LSE (e.g., existing merchant generation or units under construction), industry associations, including IEP and WPTF, should voluntarily provide the information. Information should be provided by Dec. 14, 2004 (see schedule).

2. 2006, 80/20 (1 in 5) peak load forecast for the ISO Control Area and corresponding coincident LSE load levels.

    Responsibility: CEC should provide this information to the PTOs from most recent IEPR forecast information or as otherwise available.

3. Network model for the ISO Controlled Grid for the year 2006. Bus load levels provided in the network model must be consistent with load levels in Item 2 above. Pmax of generation units must be equal to Summer Peak Net Dependable Capacity. For other than Thermal generation, Pgen should be equal to Summer Peak Qualified Capacity.

    Responsibility: The starting base case will be a 2006 ISO Controlled-Grid Summer Peak Base Case provided by ISO to Participating Transmission Owners (“PTO”). PTOs will make the necessary modifications to the starting base case based on the information obtained in #1 and provide modified case along with documentation of the changes to the ISO. Generation owners and other stakeholders will also provide information to the ISO, also as set forth in #1. To the extent possible, generation owners and other stakeholders should provide major changes in the form of GE PSLF change files.

4. NERC Category B and C (excluding C.3) power flow contingency files, including remedial action and special protection schemes for the year 2006, computer readable by a contingency processing program along with information defining the format.

    Responsibility: PTOs as set forth in the attached schedule.

5. Complete description of operations of all remedial action schemes and special protection schemes for the year 2006, in the ISO Controlled Grid.

    Responsibility: PTOs as set forth in the attached schedule.

(END OF APPENDIX D)

APPENDIX E

Whitepaper

by

Powerex Corp.

"A Pacific Northwest Marketer's Perspective

on

Counting Imports towards

California's Resource Adequacy Requirement"

February 24, 2005

Introduction

Powerex has been an active participant in the Commission's Phase 2 Resource Adequacy workshops. Powerex hopes it has offered constructive input from a Pacific Northwest importer's perspective to aid in California's efforts to work out the implementation details of the Commission's resource adequacy requirement.

Powerex believes that there is a need for the Commission to make sure that its RAR framework is integrated with the operations of the Western electricity markets so as not to create significant seams issues. There are significant benefits to California and the rest of the West in pursuit of a seamless Western market, however; certain approaches to implementing the Commission's RAR framework may result in unintended consequences that would negate those benefits.

Powerex appreciates the challenges facing the Commission Staff in working through the workshop issues derived from the October 28 decision and that there has not always been enough time to address all those issues to the fullest.

Powerex offers these comments to assist Commission Staff in its preparation of the Phase 2 Workshop report and to elaborate on issues related to the treatment of imports under the RAR framework.

Summary

A number of significant open issues were raised during the Phase 2 workshops about the treatment of imports under the RAR framework. Powerex attempted to address many of the import issues during the discussion but some were not addressed due to the limited workshop time available. The following is a summary of those issues and Powerex's perspective on how they can be resolved.

1) Continued Consensus on Counting Protocols for Import Contracts based on the Phase 1 Workshop Report limited only by Intertie Capability
2) Import Contracts are not Limited to Energy Products – Import Backed Capacity Call Options are a Valuable Product to LSEs
3) Adopt a More Reasonable CAISO Offer Requirement for Import Capacity Call Options
4) Capacity Tagging Requirements for Imports are Unknown
5) Allow Import Contracts Delivering to an Internal Hub
6) CAISO FTRs should not be Required to Count Import Contracts
7) Linkages between Resource Adequacy and Financial Adequacy

1) Continued Consensus on Counting Protocols for Import Contracts based on Phase 1 Workshop Report limited only by Intertie Capability

During the Phase 2 workshop discussions on the "Firm LD" contract issue, the issue of import contracts was discussed and again the consensus was that import contracts count fully towards RAR limited only by the CAISO's deliverability test for intertie capability.

Powerex provided in an e-mail to Sue Mara representing AReM, the lead of the "Firm LD" working group, an Overview of the Counting Protocols for Imports and that those protocols had been adopted by the Commission in its Oct. 28 decision. I have included the contents of the e-mail in **Attachment A**.

2) Import Contracts are not Limited to Energy Products – Import backed Capacity Call Options are a Valuable Product to LSEs

During the course of discussions at the Phase 2 workshop and related conference calls with the "Capacity Product" and "Firm LD" working groups, there was a lack of clarity around the actual types of import contracts that would seek to be RA qualified. There was also a suggestion that mid- to long-term RA contracts include a provision to allow for re-pricing of the product should the qualifying capacity of the RA resource be reduced.

Capacity and Energy Import Contracts

The types of import contracts would not be limited to energy products as Powerex believes that importers do now and would continue to sell capacity products, such as capacity call options. These import capacity products would need to meet the same import counting protocols as import contracts for energy when the energy is called upon under the terms of the call option to count towards RAR. The import contracts for these energy or capacity call option products may or may not identify a specific resource or set of resources. As outlined in the Phase 1 Workshop Report, import contracts are not required to identify a specific resource or set of resources to meet RAR. It was recognized that there is seasonal diversity between the winter peaking Pacific Northwest and summer peaking California/Southwest region that would not require import contracts to identify a specific resource in order to count towards RA which is a unique aspect of the Western electricity marketplace. To include such a requirement would be a disincentive for importers and limit the pool of import resources that could be committed to California for RA purposes. Buyers and sellers may bilaterally agree to include references to specific resources or set of resources, but would not be obligated to do so to meet RAR.

Re-pricing Provision

Powerex feels that a 're-price' provision is not prudent as it would force Sellers to include a risk premium into their pricing which would ultimately increase costs to California ratepayers with questionable benefit. Powerex suggest that a more reasonable approach would be to grandfather existing contracts and make post-transition period contracts subject to any changes in the counting protocols.

3) Adopt a More Reasonable CAISO Offer Requirement for Import Capacity Call Options

A significant issue that was not addressed during the Phase 2 workshops due to time limitations was the applicability of the must offer requirement to RA qualified import contracts. In the Commission's Oct. 28 decision ".. all resources identified as satisfying RAR shall conform to a sequence of requirements to be scheduled by the LSE, then bid into Day-Ahead markets if not scheduled, and then be subject to RUC if the bid is not accepted." Powerex requests that the Commission consider the practical and cost implications of imposing an identical must offer obligation that now exists with generation inside the CAISO control area to future RA qualified import contracts.

In particular, such a requirement would affect import backed Day Ahead capacity call options which are only scheduled when called on by the LSE. When Day Ahead options are currently sold in the WECC, the standard exercise time is 06:30 am on the normal preschedule day. If the option is not exercised, the seller is relieved of their obligation for that day and is free to re-market the energy component of the option elsewhere. This is an important feature, since the daily cash markets are active between 06:00 – 07:30 each morning, so the feature affords the seller an opportunity to re-market the energy and recoup some value from the energy under the call option if the original option buyer chooses not to exercise.

When purchasing capacity products with a high strike price (i.e. relatively high energy price that the buyer pays the seller if the buyer exercises the call option) LSE's are essentially buying an insurance product which gives the LSE protection against daily volatility from adverse weather, fuel supply and loads. By purchasing these capacity products, LSEs' are securing a capacity product with a low premium price in the form of a capacity payment due to the assumption that there is a low probability that these products will be exercised. When pricing the call options, sellers are able to set lower premium prices based on their assumptions as to how often these products will be exercised. If a seller were to sell a capacity product that was expected to be exercised 20% of the days during the term then the seller could assume that he or she would be able to market the energy between 06:30 – 7:30 am approximately 80% of the time. Absent this assumed flexibility the seller would be required to increase the premium to the LSE to reflect the cost for the lost opportunity of being able to remarket the energy beyond the standard exercise time. The longer the period that the buyer has to exercise the call option, the greater the premium.

Under a stringent application of the Commission offer requirement, the seller may be bound to hold the option past 06:30 am for the proposed CAISO Day Ahead market (DA), followed by the proposed CAISO DA Residual Unit Commitment (RUC) market and potentially even the CAISO Hour Ahead (HA) market and HA RUC market. Aside from the fact that no details regarding these future markets (including timing) are currently available, it is clear that if the seller agrees to such terms it will forgo the opportunity to re-market the energy under these options to other markets in the Day Ahead and potentially Real-time markets.

This sequential 'must offer' feature of these options will substantially increase the cost of these options to LSEs. Under standard options, if the buyer does not exercise by 06:30 am, the seller is free to re-market its energy to the Alberta Power Pool, bilateral markets in California, the Pacific Northwest and the Southwest (PV/MEAD/Four Corners). With the sequential feature, seller would have to calculate its lost opportunity cost of not being able to sell its energy to these other markets. If the CAISO RUC market does not accept seller's bids, then the seller could be left with a situation whereby it has no sales for the day on the capacity allocated to RA. This opportunity cost will increase as each sequential requirement is added (e.g. an Hour Ahead RUC requirement would force seller to price in its lost opportunity cost from potential real-time sales).

The major benefit of a DA call option is that it will give the LSE first call on energy (up to 06:30 am) each day before the seller goes to the market with its energy. The DA call feature will give the LSE the protection against daily volatility from adverse weather and loads. We believe the added benefit to the buyer from requiring the option to be committed past 06:30 am (up to 11:00 am for RUC) is overshadowed by the huge opportunity cost this feature places on the seller.

Powerex feels it is most economic for the buyer to only have a 06:30 am call obligation on the seller and to require rights beyond that time may not be worth the additional cost to ratepayers.

Powerex proposes that import capacity call options be exempt from any requirement to meet the CAISO must offer obligation or, alternatively, by limiting the offer obligation to the CAISO DA market or DA RUC market. Powerex strongly believes that either of its proposed approaches represents a reasonable tradeoff between cost and reliability benefits for California electricity consumers.

4) Capacity Tagging Requirements for Imports are Unknown

The exact details of a capacity tagging requirement are still very much unknown and there was no substantial discussion at the workshops or related conference calls on how to treat imports under a capacity tagging requirement. Powerex believes any retroactive application of a tagging requirement would create a substantial amount of uncertainty for Sellers and would be a disincentive to enter into RA contracts with LSEs. Powerex believes that there should not be a requirement for tagging from specific units for RA resources outside the CAISO control area where the RA resource is a portion of a Seller's system or portfolio of resources. For example, a unit specific tagging requirement makes little sense for system resources based on large hydroelectric resources outside California. Powerex suggests tagging be done from systems (external control areas) rather than individual units as this will provide a more reliable product for California.

5) Allow Import Contracts Delivering to an Internal Hub

The issue of import contracts with a delivery point at NP15, SP15 or future CAISO market hub being different than intra-ISO control area Firm LD contracts had some limited discussion among the "Firm LD" working group and was an issue Powerex raised with the

Commission during Phase 1 in its filed comments. TURN supported Powerex's request for clarification on this issue in its reply comments to the ALJ July 8 Draft Decision.[54] An RA contract with an importer delivering at NP15 or SP15 simply means that the importer takes on the congestion risk between the intertie point and the CAISO market hub (today that would NP15 or SP15) instead of the LSE. For RA purposes, the contract would still be supported by an import schedule subject to the counting protocols for imports.

6) CAISO FTRs should not be Required to Count Import Contracts

The requirement that import contracts have FTRs was another issue raised during the workshop that was already addressed in Phase 1. The resolutions was that FTRs need <u>NOT</u> be required for RA purposes. Powerex feels that FTRs or CRRs should NOT be required before an LSE can count import contracts toward resource adequacy. Instead, the expected OTC under normal operating conditions should be allocated to LSEs. In this way the CAISO can be reasonably assured that total contracted imports across any one intertie will not exceed the OTC of that iinterite under normal operating conditions and each LSE can manage its own share of OTC as it sees fit based on the final allocation methodology.

This is necessary because the current methodology of calculating available FTRs is conservative. For example, for 2004 approximately 550 MW of FTRs were auctioned at COB, whereas on most days the available New Firm Use (NFU) can range from 1,200 MW up to 2,000 MW. To require FTRs would essentially prevent needed import resources to count towards RA and would not allow LSEs to meet the Commission's 15-17% reserve margin. The timing of the FTR or CRR auction is also unknown and may not match with the LSE's RA filing timeline.

7) Linkages between Resource Adequacy and Financial Adequacy

A significant amount of workshop time has been spent discussing the potential unreliable nature of the "CAISO System" Energy or Capacity contract often referred to as Firm LD contracts.

Specifically, some participants throughout the Phase 1 and 2 workshops have expressed concerns that the Liquidated Damages (LD) provisions in both the WSPP and EEI master agreements give the seller the option to financially settle the contract. Powerex has always believed that the products sold under the WSPP and EEI are physical power products and that the intent of the LD provision is to provide both the seller and buyer with a financial remedy for their replacement and or resale costs in the event that the other party fails to deliver or receive the energy. Powerex would also like to inform the Commission that the predominant master agreement for natural gas transactions used in North America, the North American Energy Standards Board (NAESB) agreement also contains a LD provision for physical natural gas

[54] TURN stated in its Sep. 27, 2004 reply comments, p. 4: "Finally, TURN supports the clarification sought by Powerex that firm import contracts from the Pacific Northwest with NP 15 or SP-15 delivery points should not be impacted by the Commission's determinations with respect to intra-ISO control area Firm LD arrangements. Such inter-control area sales are "truly firm" and backed by spinning reserves within the control area of origin, so they are not subject to the same potential performance problems."

delivery. Section 3 (Performance Obligation) of the NAESB agreement outlines the financial remedy for sellers and buyers in the event that either party fails to receive or deliver natural gas. Powerex believes that this fact demonstrating the prevalence of this provision in both power and natural gas contracts will help to clarify to the Commission and workshop participants that an LD provision is not a reflection of the physical reliability of the underlying power and natural gas products.

The focus during the workshops on the LD provision of these contracts strays from what should be the more critical concern of the Commission i.e. the financial adequacy of the counterparties behind the generation resources being committed for RA purposes. Many of the counterparties that sell today's CAISO System product but do not own physical assets have a far superior credit standing than many of the owners of generation inside the CAISO control area.

The Commission needs to recognize that there are linkages between financial adequacy and resource adequacy i.e. the existence of a physical generator does not in itself ensure resource adequacy if there is not a creditworthy owner behind the generator. For example, a generator that does not have the financial adequacy to secure fuel supplies and pipeline capacity makes that physical generator less reliable compared to a CAISO System product supplied from a creditworthy marketer. The creditworthiness of the seller of RA resources is by far a more significant determinant of reliability then any LD provision. The Commission should closely examine the true reliability and financial benefit that CAISO System products provide before deciding on its future. In the short term, there is a significant projected resource shortfall in Southern California and any changes to the current market with out some orderly transition may in fact reduce CAISO system reliability.

Attachment A

Overview of the Counting Protocols for Imports

The CPUC voted out the attached opinion on resource adequacy on Oct. 28/04. The attached opinion is the draft version that was put to vote so the final version is identical but has not yet been posted to the CPUC website (CPUC staff confirmed the same during a FERC technical conference on the subject yesterday).

The opinion accepts the counting protocol for import contracts. Specifically, the opinion states in section 3.5.1 that: "Section 5 of the Workshop Report provides a series of formulas generally agreed to by the parties for computing qualifying capacity for each class of resource. We endorse the general approach of beginning with net dependable capacity and making specific adjustments appropriate to that class of resource. Unless specifically addressed in the remainder of this decision, we accept the formulas included in Section 5 of the workshop report as written." The CPUC opinion made no change to the counting formula for import contracts so the formula for imports is adopted.

The following is the formula for counting imports (p. 21 of the Workshop Report under Contracts section).

QC= Contract Amount provided the contract:
1. Is an Import Energy Product with operating reserves
2. Cannot be curtailed for economic reasons
3a. Is delivered on transmission that cannot be curtailed in operating hours for economic reasons or bumped by higher priority transmission OR
3b. Specifies firm delivery point (not seller's choice)

The following was an issue that the CAISO raised about WSPP schedule C import contracts that was reflected in the Workshop Report. In the report it stated:
"The CAISO expressed concern that this requirement would still allow for the seller to curtail its deliveries to meet native load requirements. The CAISO stated that it needs to research what triggers the right to curtail to meet native load, and depending on the outcome of that research, they could agree to the definition for import contracts to count. In addition, the CAISO indicated that it is concerned that WSPP Schedule C has an element that allows substitution of financial payment for failure to deliver. The CAISO indicated it needed to do more research on whether WSPP Schedule C would meet the definition of "economic reasons" before agreeing to this definition for import contracts to count."

However in its comments to the Workshop Report, the CAISO no longer had concerns about WSPP Schedule C system import contracts. The following is what they stated on the issue (p. 20-21 of CAISO Comments to Workshop Report)

"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."

Deliverability is still an open issue for both inside California generation and imports. The CPUC order directed the CAISO to conducts it baseline deliverability analysis it proposed during the Phase 1 Workshops. The results of the analysis will allow parties to be better informed and able to develop a consensus on how to allocate internal transmission and import transmission capability between the CAISO and neighbouring control areas for resource adequacy. The following is how the order summed up the state of this issue for import transmission (p. 32-33):

"Import capacity allocations to LSEs also received no consensus. Parties' comments reveal many disparate ideas ranging from use of firm transmission rights to pro rata allocations among LSEs using historic LSE loads. Rights in excess of an LSE's needs could be sold. We are not willing to provide guidance on the basis of the information at hand. Alternative allocations of import capacity should be the subject of further discussion in Phase 2, and perhaps informed by the baseline analysis that CAISO has offered to conduct."

In summary, import contracts count 100% towards an LSE's resource adequacy requirement so long as they are allocated or have access to a portion of the import transmission capacity to make the import deliverable.

(END OF APPENDIX E)

APPENDIX F

Straw Proposal #2

Counting Resources under Construction and Estimating Dates of Commercial Operation

Introduction

Under the California Public Utilities Commission's ("CPUC") recent decision on resource adequacy ("RA Decision"),[55] the capacity of resources under construction should be allowed to be counted toward a load serving entity's ("LSE") resource adequacy obligation at some point in time. The RA Decision states the following:

> Looking just one year ahead, we expect that LSE reliance on a new resource still under construction to demonstrate compliance will be a rare occurrence. Nonetheless, we must establish conventions for how to treat these generators. The Workshop Report describes the inability of the parties to come to agreement about how to count resources under construction that might become operational just before or during the relevant May to September period, and the comments reflect continuing disagreement…While the comments of PG&E and the reply comments of CAISO are the most helpful, they are predicated on new systems of tracking and publicly disclosing CODs for large projects licensed by the CEC and smaller ones sited through local processes. We believe the databases maintained by the CEC and CAISO are the appropriate foundation for determining CODs. We direct that parties flesh out these proposals in Phase 2. We wish to establish whether the CEC and CAISO are willing to make modifications to track projects more closely and to allow these updated data to be accessed publicly for use by LSEs in their compliance filings.

The CPUC issued a matrix of items to be addressed in the Phase 2 workshops.[56] Item 10 on the matrix tasks the California Independent System Operator "(CAISO") with developing a straw proposal for discussion at the Phase 2 workshops on "methods for estimating COD dates for generators of all sizes based on appropriate modifications to existing CEC and CAISO tracking systems."

The CAISO's straw proposal is provided below.

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[55] See D.04-10-035, October 28, 2004.

[56] The CPUC document, issued November 19, 2004, is titled, "Attachment A, Resource Adequacy Requirements Phase 2 Workshops and Following Approval Processes."

Proposal

Key Elements

- The CAISO and California Energy Commission ("CEC") are both willing to make modifications to their existing procedures and databases to facilitate improved tracking of resources.
- The current method for reporting a date of commercial operation will be improved through consistent use of a new, common, and clear definition of commercial operation.
- The developer of a resource under construction will self-report the expected date of commercial operation of that resource to the appropriate organization, which varies depending on the size of the resource and the applicable jurisdiction. The expected date of commercial operation will be reported by the developer as part of either its: (1) interconnection application to the CAISO, (2) Application for Construction to the CEC, (3) application for interconnection with the local utility for resources interconnecting at the distribution level of the electrical system, or (4) application to the CAISO for participating in the energy market regardless of interconnection.
- The CAISO and CEC will continue to undertake selected and periodic site visits, as a normal part of doing business, to assess progress of significant resources under construction.
- The CAISO and CEC will formally reinstate joint, monthly or bi-weekly status review meetings to closely track resources that are under construction.
- The CAISO and CEC will jointly create and post monthly, on a public website, a new report, created specifically for the use of LSEs for resource adequacy, that lists the expected date of "Commercial Operation" (see definition below), as reported by the developer, of each resource under construction or with an expected date of Commercial Operation of one year or less, that has a nameplate capacity rating of 1 MW or greater. The report will also include the date, as certified and reported by the developer, that the resource achieved "Operational Status" (see definition below). The report will be posted no later than the 15th day of the each month and will contain a limited set of data to minimize concerns over confidentiality. For example, the monthly report will include the name of the facility, developer, location, nameplate capacity, and reported dates of Commercial Operation and Operational Status. Changes in the status of any of the foregoing information provided by the developer through the end of the first calendar day of each month (12:00 a.m. midnight) will be included in the monthly report. If discrepancies in the data reported by the developer are discovered, the CEC and CAISO will contact the developer to reconcile the discrepancy and obtain a current and consistent date from the developer to use in the monthly report. Thus, only consistent dates will be posted in the monthly report.
- Each developer will be required to self-report to the CAISO and CEC the expected date of Commercial Operation of each resource on July 1 each year, and within 30 calendar days after a previously reported date of Commercial Operation changes.

Definitions

- **Operational Status** will be defined as: The status of a Generating Unit at a Generating Facility that has completed the interconnection procedures of the applicable interconnection authority, physically interconnected and paralleled with the existing electrical system (with the pre-approval of the applicable transmission owner and CAISO grid operations), completed necessary contracts and performance testing, has a test energy schedule submitted to the CAISO Outage Coordination office, meter data is accessible and capable of being downloaded, and the resource developer has submitted an affidavit to the entity that posts the new monthly report on the public website certifying that the resource has achieved Operational Status.
- **Actual Date of Operational Status** will be defined as: The date that a Generating Unit at a Generating Facility achieves Operational Status as certified in the affidavit submitted by the resource developer to the entity that posts the new monthly report on the public website.
- **Commercial Operation** will be defined as: The status of a Generating Unit at a Generating Facility that has completed construction, interconnected to the applicable distribution or transmission system, completed all start-up, commissioning and performance testing, received final approvals from the applicable distribution or transmission provider, and commenced scheduling or bidding for the sale of electricity in the forward market. The establishment of contracts and agreements between an LSE and an energy supplier or developer will have no bearing or affect on the determination of Commercial Operation.
- **As Filed Date of Commercial Operation** will be defined as: The date self-reported by the resource developer as part of either its: (1) interconnection application to the CAISO, (2) Application for Construction with the CEC, (3) application for interconnection with the local utility, for resources interconnecting at the distribution level of the electrical system, or (4) application with the CAISO for participating in the energy market regardless of interconnection, on which a Generating Unit at a Generating Facility is proposed or expected to commence Commercial Operation.
- **Revised Date of Commercial Operation** will be defined as: The revised date self-reported by the resource developer on which a Generating Unit at a Generating Facility is expected to commence Commercial Operation. The revised date will be self-reported on July 1 each year, or within 30 calendar days of a change in the previously reported date of Commercial Operation.

<u>Qualifying to Meet Resource Adequacy Requirements</u>

- For the annual "year-ahead showing" of resource adequacy,[57]" an LSE will be able to include, for any given month, a resource that is still under construction, provided that (1) the Revised Date of Commercial Operation posted on the public web site is no

[57] The "year-ahead showing" will be made by an LSE in September of each year and will show how the LSE has met its resource adequacy requirements for the upcoming five summer months of May through September.

later than the first calendar day of the applicable month, and (2) Operational Status is expected to be achieved no less than 60 days prior to that date. A resource that meets these criteria will be considered to have achieved "Qualified for Resource Adequacy" ("QRA") status for the year-ahead showing. For example, a resource that the developer reports is expected to achieve Commercial Operation no later than July 1, 2008 could be used by a LSE in September 2007 to demonstrate compliance in its year-ahead showing for the month of July 2008. The developer is expected to achieve Operational Status no later than May 1, 2008. As another example, a resource that the developer reports is expected to achieve Commercial Operation no later than August 14, 2009 could be used by a LSE in September 2008 to demonstrate compliance in its year-ahead showing for the month of September 2009. The developer is expected to achieve Operational Status no later than July 1, 2009.

- For the monthly "month-ahead showing" of resource adequacy,[58] the ability for a resource to qualify for resource adequacy is dependent upon the unit achieving operational status. Therefore, to be included in a month-ahead showing, a resource must have achieved Operational Status for 60 days prior to the month in which it may be counted for resource adequacy purposes. Thus, a resource still under construction will not be allowed for use by an LSE to demonstrate compliance in its month-ahead showing. It is imperative that, on a month-ahead basis, the LSE, CAISO and local utility (as applicable) have 100% confidence that a resource has actually achieved Operational Status. This requirement is essential for reliable operation of the electrical system, and is necessary to ensure that each resource is actually constructed, interconnected, tested, and fully available for dispatch in the month in which it is obligated to serve load and provide reserves. For the month-ahead showing, a LSE will be able to include, for any given month, a resource that has achieved Operational Status no later than the first day of the month in which it is preparing its month-ahead showing report. This conservative timing requirement is needed to provide LSEs with sufficient time to make alternative arrangements if a resource that is under construction does not achieve Operational Status by the first day of the month in which the month-ahead showing report is being prepared. This requirement will allow a LSE time from the second day of the month to arrange for replacement capacity that can be included in the monthly showing by the time the report is issued. For example, in making its month-ahead showing for the month of August 2011, an LSE would file its month-ahead showing by June 30, 2011. The showing distributed by June 30, 2011 could only include a resource that has achieved Operational Status no later than June 1, 2011.

<u>Example</u>

[58] The "month-ahead showing" will be made by an LSE one month in advance and will show how the LSE has met its resource adequacy requirements for the upcoming month. At this time, the specific requirements of the "month-ahead showing" have not yet been established, and are the subject of separate Phase 2 workshops.

- An example of the proposed contents of the new report that would be posted to a public website is provided below. This example shows how the requirements discussed above would be implemented.

Monthly Report on Resources Under Construction
Data as of 12:00 A.M. August 1, 2007
Issued August 14, 2007

Project Name	Developer	Nameplate Capacity (MW)	Summer Dependable Capacity (MW)	Location	Trans-mission Owner	Status	As Filed Date of Commercial Operation	Revised Date of Commercial Operation	Starting Month QRA[59] Status for Year-Ahead Showing	Actual Date of Operational Status	Starting Month QRA[5] Status for Month-Ahead Showing
Blue Units 2 and 3	Acme Power	500	480	Shasta County	URE	Construction	7/1/2008	7/1/2008	7/2008	5/1/2008	7/2008
West Simple Cycle	New Energy Irrigation District	95	85	Sacramento County	FMW	Construction	8/14/2009	8/14/2009	9/2009	7/1/2009	9/2009
Greenwood	Energy Innovators	546	524	Solano County	PTS	Financing	3/1/2010	7/22/2011	8/2011	6/1/2011	8/2011

(END OF APPENDIX F)

[59] QRA – Qualified for Resource Adequacy.

APPENDIX G

First Revised
STRAW PROPOSAL

CPUC Resource Adequacy Requirements

Local Capacity

Study Methodology and Criteria

Prepared by California ISO staff
for the CPUC

January 25, 2005 Resource Adequacy Workshop

Executive Summary & Introduction

This document details a straw proposal for a technical study methodology and criteria that could be followed to identify the local capacity requirements for the California ISO ("ISO") Controlled Grid "ISO Controlled Grid Local Capacity Technical Study" or "Study". Results obtained from the Study are intended to provide the technical basis for identifying the capacity requirements expressed in mega-Watts ("MW") that are necessary for the ISO to provide reliable operation of the ISO Controlled Grid and to satisfy both the system and local deliverability requirements established by the CPUC's orders on Resource Adequacy.

The intent of the proposed Study is to identify, to the greatest extent feasible, a reasonably stable minimum capacity procurement target (MW) for load-serving entities in each identified local area. The Study criteria are designed to determine the minimum amount of capacity necessary to maintain reliable grid operation under certain identified major contingencies in each area. As a general matter, the proposed criteria are focused on the loss of large transmission elements, i.e., high voltage transmission lines and/or transformers, within the local area. Other large contingencies, such as the loss of major generating facilities within the area, are also considered and examined**.**

Notwithstanding the ISO's intent to identify the minimum amount of capacity in each area necessary to respond to the large contingencies noted above, it is important to clarify that it is not the ISO's proposal to identify the minimum amount of capacity in each area that would be necessary to respond to *all* contingencies or possible system conditions. Thus, this approach inherently embraces the understanding that the ISO may in some instances have to commit additional resources and/or take certain operating actions, in the day-ahead and real-time timeframes, in order to address operating conditions that arise on the grid or in the ISO's markets.

While it is the ISO's intent and long-term objective to phase out RMR Generation, any such transition must be done prudently over an appropriate timeframe. In the event that additional capacity is required above the amount identified pursuant to the Study and procured by the LSEs, the ISO will have to determine the appropriate timeframe and manner to procure the additional necessary capacity. While the ISO remains confident that the majority of its capacity requirements will be satisfied under the CPUC's Resource Adequacy Requirements, there may be a need for the ISO to procure resources prior to the day-ahead timeframe in order to ensure that such resources are and remain available to the ISO. It is, of course, the objective of the proposed Study methodology and criteria to determine LSE procurement requirements that will fully satisfy the ISO's real-time operating needs under most system conditions, and thus to minimize the need for any additional procurement of capacity by the ISO.

To achieve this objective, the ISO believes that it is imperative that the CPUC adopt local capacity requirements that are clear and specific for the coming year and relatively stable over a 3-5 year timeframe, so that economic procurement decisions can be made for the longer time horizon rather than only for one year at a time.

The ISO recognizes that to achieve the goal of a stable capacity requirement, transmission planning, both at the ISO and state regulatory agencies, must be coordinated with RAR obligations and processes. Similarly, the effect of changes in load forecasts over time must be addressed and accommodated. To the extent such issues can be reconciled and stable capacity requirements are established, load-serving entities can consider a variety of options to satisfy their local capacity requirements: contract with existing or new supply, build new generation, build/sponsor new transmission, and develop viable demand response. While these are policy issues that are beyond the scope of the Study, these issues are nonetheless important to consider when structuring the technical requirements considered in this straw proposal.

Study Scope

The Study Scope includes the study objectives, responsibilities, criteria and methodology. These scope items are discussed below.

A. Objectives

The ISO would perform technical studies across the ISO Controlled Grid to determine the following:

- Total generation capacity requirements in MW for all identified local areas of the grid. ;
- A list of eligible generating units within each identified local area eligible to meet the local requirements. In principle this will include all generating units within the local area that are connected to the ISO grid and available to the ISO in a manner consistent with the Must Offer Obligations specified in the CPUC orders. The list of generation units will be determined in accordance with the ISO Local Reliability Criteria described in Attachment 1.; and
- Generator deficiencies in local areas to highlight areas of the ISO Controlled Grid where the reliability criteria cannot be maintained according to the ISO Local Reliability Criteria.

B. Information Requirements

Generation Information - In order to perform the Study, the ISO will rely on information available to it through existing grid planning studies, generator information available through: each Participating Generator's Schedule 1 to the ISO's Participating Generator Agreement, the ISO's Master File, ISO Outage Coordination, and the California Energy Commission. To the extent that additional information is required from a Participating Generator, the ISO will request such information for the Generating Unit and the Participating Generator will provide the requisite information.

Transmission Information – All Participating Transmission Owners ("PTOs") will be responsible for providing accurate system configuration information and accurate representation of their transmission systems for the season and year being studied. The ISO will obtain the applicable system configuration information for neighboring Control Areas through existing grid planning processes and sources such as the WECC.

Load Information – Based on existing practice, the PTOs will provide to the ISO the accurate local area representations with a defined relationship to the applicable system forecast. Alternatively, the ISO suggests that it might use the LSE load forecast data provided to the PTO/CEC and adjusted as the CEC finds necessary for resource adequacy purposes, or that other ways could be developed to ensure that accurate load information is used.

It is understood that the ISO will keep all market-sensitive information confidential, subject to the appropriate protections.

C. Criteria and Methodology

The objective of the study is to identify the minimum capacity requirement for each identified local area while maximizing the utilization of area transmission facilities to access capacity external to the local area for local area reliability needs. To the extent that the local area transmission capability is insufficient to meet the local area reliability needs, local capacity will be needed to provide for operation of the ISO Controlled Grid in accordance with applicable reliability standards.

For purposes of the Study, the applicable reliability standards include both the ISO's established planning and operating standards. The Planning and Operations Criteria used in performing the Study are consistent with NERC/WECC/ISO planning standards, as they may be modified, and will address system performance levels A, B and C.[60] In addition, the study methodology for determining the local area requirements conforms to any operations procedures specific to each local area as well as the methodology used in the ISO/PTO's regular planning studies.

The ISO's existing Planning Standards require each PTO to plan their systems to the ISO Planning Standards. In addition, ISO Operations identifies additional requirements necessary to address certain operational contingencies required to meet real time reliability.

Key Study Assumptions (Base Cases and Local Area Cases)

The ISO will conduct the Study using the GE PSLF power flow/stability program. A summer peak ISO Controlled Grid base case will be modified to accurately represent the year being studied. The ISO will endeavor to develop a comprehensive modified base case that represents all network configuration and generation additions or modifications expected to be in service for each year studied. If the in-service date of any transmission or generation facility is

[60] Performance Levels A, B and C are defined in the NERC Planning Standards to address steady-state overloads, N-1 contingencies and N-2 contingencies, respectively.

uncertain, such facilities will be modeled in the base case with a status of "off". In such cases and if deemed necessary by the ISO, the ISO will perform sensitivity studies as part of the overall Study effort to determine how the inclusion of such facilities impacts the Study results.

The ISO will use the following assumptions for preparation of the base cases to be used in the Study:

Network Related Assumptions

- The power flow base cases used in the Study will incorporate the PTO's most recent Ten Year Annual Expansion Plan configuration modeling for the Study-year;
- New projects and/or changes to each PTO's network configuration must be approved through the ISO's Grid Planning Process before they will be included in the base cases.
- The PTOs will be responsible for assuring that their system network configuration is consistent with the year being studied. If modifications to the base-case representation are required, the PTO's will identify and tabulate them, by year, for inclusion in the Study representation.

D. Load Related Assumptions

- For the years being studied, the ISO will study the number of local areas required to meet the applicable reliability requirements of the ISO Controlled Grid. The power flow base case used in the Study will be adjusted to reflect a one-in-ten-year peak load forecast for each local area studied.[61] Any neighboring local areas will be modeled at coincident load levels expected to be achieved when the main local area peaks. The rest of the areas will be adjusted to the latest California Energy Commission's coincident peak demand for the corresponding year(s) being studied.
- To assure a reasonable representation of loads across the California system, loads on systems within California that are not located within a PTO's system will be adjusted in proportion to the nearest PTO system load.

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[61] The peak load to be used in the analysis would be consistent with the methodology used in the ISO Grid Expansion Planning process: 1 in 2-year for system wide load, 1 in 5-year for zonal load and 1 in 10-year for areas smaller than a zone. The more stringent 1 in 10-year requirement for studies of local load serving areas is necessary because fewer options exist during actual operation to mitigate performance concerns. In addition, there is less diversity and thus less certainty in load compared to regional load forecast. Having this standard for local areas will be consistent with the grid expansion plan (all transmission expansion projects are evaluated and approved based on these 1 in 10-year load levels) so that evaluation of proposed generation and transmission projects would be on a level playing field.

- Reactive load will be represented to reflect reasonable values for the operating conditions being studied as demonstrated by recorded data and/or PTO reactive planning programs.

E. Generation Related Assumptions

For the purpose of this Study, the following assumptions shall be used to determine whether or not generation will normally expected to be on-line and available. Such resources are assumed to have: an assured revenue stream, an obligation to be on-line in order to serve their constituents or contract party, or a bilateral contract between Transmission Owners that obligate each-other to provide help during times of reliability need.

Regulatory Must Take

- Regulatory "Must Take" resources (i.e. generating units from Nuclear, QF, and Public Power Utilities sources) will be dispatched at their contract ratings; otherwise the CPUC RAR counting conventions will be used.

Hydro-Electric

- Hydro generation located within the ISO Controlled Grid will be dispatched according to CPUC RAR counting conventions.

Qualifying Facility

- The QF generation levels modeled in the Study shall be provided by the entity under contract with each facility and shall represent the expected operating level during the peak.
- All QF generation connected to busses rated 230 kV and above will be explicitly represented in the power flow and stability base cases.
- All QF generation connected to busses rated below 230 kV to 60 kV inclusive, will be explicitly represented in the power flow base cases and may be load netted for stability analyses. If multiple QF generating units are connected to the same bus, they may be aggregated at that bus and represented as an equivalent representation in the power flow base cases and for stability analyses if stability data is not available.
- Most QF generation connected to busses rated below 60 kV will be netted with the nearest load that is electrically tied to the respective generating unit.
- All QF generation explicitly represented in the power flow base cases will have their reactive power capabilities modeled according to contractual requirements, otherwise RAR qualified capacity will be used to determine their reactive representation. If available, actual reactive power capabilities from manufacturers' or field test data will be represented.

Non-jurisdictional

- MUNI, state and federal owned generating units or units under any availability-type contract with an LSE is assumed "on".

Miscellaneous

- Before the studies are initiated, the base cases should have enough generation on-line in order to maintain all the inter-regional 500 kV path flows below their operating transfer capability ratings for the season being studied.[62] The CPUC Resource Adequacy requirements should ensure that a sufficient number of generation resources will be available to maintain the inter-regional 500 kV path flows within limits, and this generation will be operated in the study in a manner that maximizes the generation resource needs in a specific local area. For example, when assessing the generation requirements for a specific local area, the generation units outside of that local area will be committed and dispatched before units inside the local area to maintain inter-regional 500 kV path flows.
- All base cases will be developed to represent a minimum operating reserve within the ISO Controlled Grid as established by WECC MORC. Based on actual operations, this requirement is typically between 5-7 percent and it must meet the requirements specified by WECC MORC on the level that the ISO commits its operating reserve.[63]
- All existing generating resources within California that are anticipated to be available for service by May 1st of the following year of study and beyond will be represented in the base case per reports published by the CEC for the year studied.

F. Transmission Related Assumptions

- To maximize transmission import capability, any remaining capacity on interconnected transmission lines will be used to import economy power from outside the local area under study.
- Imports into the ISO Controlled Grid will adhere to all established operating limitations. By example, this means that flows on the

[62] It is not anticipated that local area requirements will be identified by the ISO in order to maintain flows on the following inter-regional paths: COI, Path 15, Path 26, PDCI, Path 61, EOR, WOR, and SCIT along with all inter-control area ties. These paths are the subject of the zonal and system studies and should be enforced strictly in the resource adequacy requirements; if they are not, a local area may be identified to address potential constraints on these paths.

[63] MORC specifies that 50 percent of the operating reserve can be off-line and generating facilities that do not respond with governor action should be modeled as blocked.

California Oregon Intertie (COI) path will be represented no higher than the maximum level in the season being studied in accordance with the seasonal operating capabilities determined by the WECC Operating Transfer Capability Policy Committee (OTCPC). The flows on the Arizona to California path will be represented no higher than the maximum level allowable based on the Southern California Import Transmission (SCIT) and East-of-River (EOR) nomogram. The imports into Miguel will be limited by the Miguel Import Nomogram.

G. Local Area Cases

Local area base cases are required to assess the requirements for each local area. Local areas will be pre-identified through a stakeholder process and may be modified from time to time. The local area base cases will be developed in accordance with the assumptions discussed in sections A through D above. The forecasted local area load level will be developed by the PTO or CEC or another entity in a manner that is consistent with the assumption discussed in Section B above and will represent the 1 in 10 year local area peak load conditions (more specifically e.g. local area "coincident" peak).

Study Process

The Study process will include an investigation into potential related reliability impacts in areas that are internal to the ISO Controlled Grid. Information from previous year's results will be utilized in the current year Study to assure each Study is performed in a manner that is consistent with historical results. However, for the first year of the Study, the local area identified in the ISO Local Area Reliability Service ("LARS") studies from the previous year will be utilized. This first-year Study will focus on all areas that have generation units starting with areas identified in previous LARS studies. As required, additional studies will be conducted to address other reliability concerns within the ISO Controlled Grid. The following outline gives a general description of the Study process.

A. Base Case Development

The ISO will develop California ISO Controlled Grid base cases for the applicable year(s) being studied. These "first cut" base cases will be made available to stakeholders that are WECC members, or that have executed the necessary WECC confidentiality agreement, for review and comment. For those stakeholders who do not meet these requirements, it is the ISO's and PTO's responsibility to work with all stakeholders to assure that their comments and/or concerns are appropriately identified and documented.

The PTOs will be responsible for developing the "revised first cut" base cases by following the key base case development and modeling assumptions identified in Section III above. The preparation of the "revised first cut" base cases will be needed to ensure that the most up to date representation of the PTOs transmission system is incorporated into the base cases that will be used in the Study. As such, the PTOs will be responsible for, among other things:

- Removing incorrect or out-of-date system representation;

- Providing equipment ratings that are consistent with the ISO Transmission Register;
- Ensuring that their system representation is consistent with the PTOs latest Annual Expansion Plan that has been approved by the ISO Board of Governors.

The PTOs will provide the ISO the completed “revised first cut” base cases along with their associated dynamic data. The PTOs will be responsible for properly working base cases from which power flow and dynamic simulation analysis can be performed. Based on the PTOs “revised first cut” base cases and all stakeholder comments received, the ISO will develop the “second cut” base cases. As done for the “first cut” base cases, the “second cut” base cases will be provided to the stakeholders for their review and comment. Based on the “second cut” base cases and all appropriate stakeholder comments received, the ISO will develop the “Final” base cases for the study.

The LSEs will provide load data for Local Area Study cases. This load data will be incorporated into the “Final” base case to evaluate each local area and will create “Local Area” study cases for all of the pre-determined local areas. In each local-area case the ISO total load will remain the same as in the “Final” base case by adjusting the load in areas that are far from the local area of interest up or down as needed until total system load equals that represented in the Final base case. These Local Area Study cases will be used by the ISO to perform all technical analysis needed to determine the generation resource requirements in all of the predetermined local areas of the ISO Controlled Grid.[64]

For the years being studied, the ISO will also study a three-zone power flow base case. The three zonal areas studied will be: NP15, NP15+ZP26, and south of Path 26. The forecasted zonal load level will represent the 1 in 5 year area peak conditions (more specifically e.g. zonal area “coincident” peak). The surrounding area loads would be adjusted to maintain the Control Area total load. These studies will focus on the 500 kV system and will use the complete ISO Criteria for power flow, post-transient load flow and stability studies.

B. Reliability Evaluation of Base Case Minimum Load Conditions

While minimum load concerns (high voltage conditions and/or possible thermal loading) are not expected to be a determining factor for identifying local reliability capacity, each year the ISO will check the validity of this assumption to determine if LSE obligations (both in the aggregate as well as on a local level) should be adjusted address reliability problems that may arise under minimum load conditions.

C. Local Capacity Requirement Determination

[64] This methodology would be revisited if considering large “load pockets”.

Each limiting contingency will be subject to power flow, post-transient, and/or transient stability analysis as deemed necessary by the ISO. The overall objective of the study will be to determine the minimum generating capacity (MW) requirement for each particular local area. The required amount of local generating capacity (MW) will be determined through a procedure in which units will be individually and successively "turned off" in the base case until the criteria are no longer being met.

D. Post LSE Procurement Process

After the LSEs make their annual showing identifying the resources they have procured, the ISO will perform further analyses to determine if any additional capacity is needed in each local area, based on the contingencies and other system conditions that were not considered in the initial assessment of the minimum local area MW requirements. The ISO will document and provide the results of these analyses to the Participating Stakeholders for their review and comment. At this time the ISO will also identify any generating units the ISO believes should be procured under RMR Contracts. As noted earlier, the minimum local MW requirements for LSE procurement will be specified so as to substantially reduce the need for RMR compared to today, but at least for a transitional period may not totally eliminate that need. A stakeholder meeting will be held to provide all Participating Stakeholders the opportunity to provide their comments and concerns to the ISO prior to the Final Report being prepared.

E. Final Report

The final draft Study report will be prepared by the ISO and will contain all criteria, assumptions, methodologies, simulation results, conclusions, the LSE procured capacity, recommendations for RMR designations, and any other pertinent information that has been deemed necessary by the ISO. The schedule for conducting and releasing the Study will be determined after further discussion in the CPUC workshops intended to address RAR procurement responsibilities.

Once all appropriate stakeholder comments and concerns have been addressed, the ISO will prepare a final report entitled the "[year of study] Local Capacity Study of the ISO Controlled Grid Report" ("Final Report") and distribute it to the Participating Stakeholders.

Reliability Dispatch via LSE Resources

The LSEs will procure the MW requirements through bilateral contracts that shall include provisions consistent with the Must Offer Obligations specified in the final CPUC Resource Adequacy orders. The ISO will develop appropriate language in its Tariff to implement such Must Offer Obligations, to enable the ISO to issue dispatch notices to the resources procured by the LSEs to meet the Local Capacity requirements for all hours such resources are necessary to maintain the reliability of the ISO Controlled Grid.

Power Flow Assessment:

Contingencies	Thermal Criteria[3]	Voltage Criteria[4]
Generating unit [1, 6]	A/R	A/R
Transmission line [1, 6]	A/R	A/R
Transformer [1, 6]	A/R [5]	A/R [5]
(G-1)(L-1) [2, 6]	A/R	A/R
Overlapping [6, 7]	A/R	A/R

[1] All single contingency outages (i.e. generating unit, transmission line or transformer) will be simulated on Participating Transmission Owners' local area systems.

[2] Key generating unit out, system readjusted, followed by a line outage. This over-lapping outage is considered a single contingency within the ISO Grid Planning Criteria. Therefore, load dropping for an overlapping G-1, N-1 scenario is not permitted.

[3] Applicable Rating – Based on ISO Transmission Register or facility upgrade plans.

[4] Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate.

[5] Based on the judgment of the ISO and the facility owner, a thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.

[6] Following the first contingency (N-1), the generation must be sufficient to allow the operators to bring the system back to within acceptable (normal) operating range (voltage and loading) and/or appropriate OTC following the studied outage conditions.

[7] During normal operation or following the first contingency (N-1), the generation must be sufficient to allow the operators to prepare for the next worst N-1 or common mode N-2 without pre-contingency interruptible or firm load shedding. SPS/RAS/Safety Nets may be utilized to satisfy the criteria after the second N-1 or common mode N-2 except if the problem is of a thermal nature such that short-term ratings could be utilized to provide the operators time to shed either interruptible or firm load. T-2s (two transformer bank outages) would be excluded from the criteria.

Post Transient Load Flow Assessment:

Contingencies	Reactive Margin Criteria [2]
Selected [1]	**A/R**

[1] If power flow results indicate significant low voltages for a given power flow contingency, simulate that outage using the post transient load flow program. The post-transient assessment will develop appropriate Q/V and/or P/V curves.

[2] Applicable Rating – positive margin based on the higher of imports or load increase by 5% for N-1 contingencies, and 2.5% for N-2 contingencies.

Stability Assessment:

Contingencies	Stability Criteria [2]
Selected [1]	**A/R**

[1] Base on historical information, engineering judgment and/or if power flow or post transient study results indicate significant low voltages or marginal reactive margin for a given contingency.

[2] Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate.

Loss of Load Probability:

Loss of Load Probability ("LOLP") is a study methodology that can be used to establish the level of capacity required in each local area by performing a probabilistic analysis to achieve a specified probability for loss of load. In the established Eastern markets a one-event in ten years LOLP methodology is used to determine LSE capacity obligations. The LOLP approach provides a potentially more uniform reliability result than the proposed deterministic approach. In the future, if the LOLP approach is determined to be a more desirable approach, then the LOLP analysis will be incorporated into the criteria if and when a criteria and methodology for applying it has been developed. Any LOLP criteria and methodology will need to be reviewed by stakeholders and approved by the CPUC. Until such time, the LOLP approach will not be used to establish LSE capacity requirements, and the deterministic approach defined above will be used.

(END OF APPENDIX G)

APPENDIX H

Mirant Local Resource Adequacy Straw Proposal

The Problem

Based on discussions during the January 25-26 Resource Adequacy Workshops, it has become apparent that the process of individual LSEs meeting various local resource adequacy requirements (LRA) presents a variety of challenges, including:

- **Evaluating transmission alternatives** – even though LRA can be the result of insufficient transmission capacity, if LSEs are responsible for LRA, transmission owners have no direct incentive to reduce transmission bottlenecks.
- **Defining obligation** – determining individual LSE load obligation within load pockets could be difficult or at least complex.
- **Buyer Monopoly** – if one LSE controls all or most of the capacity needed for LRA, it may be able to use monosopy power to keep potential competitors out of the area.
- **Free-riders**, if some LSEs provide more resources than they need the requirement could be met while other LSEs are not providing contributions to the reliability of the system.
- **Small requirements** – a small LSE serving load in a load pocket could have a LRA too small to be commercially attainable or physically dispatchable.
- **Cost allocation** – how LSEs recover LRA costs from their customers. IOUs will probably be required to spread the costs over all their customers (as is done now with Reliability Services charges and procurement-related charges). Non-utility LSEs can only recover from their customers. This could create competitive imbalance, a situation where non-utility LSEs pursue customers outside load pockets (assuming they can save the utility's LRA costs) and utilities have an incentive to maintain load pockets to keep competitors out.
- **Market power** – there will be areas where all generation is needed or where one or more suppliers are pivotal, therefore some market evaluation such as a conduct and impact test for the exercise of market power may be needed.
- **Jurisdictional balance** – potential confusion/conflict between FERC's jurisdiction over transmission and CPUC jurisdiction over RA.

Potential Solution

There is a fairly straightforward process that overcomes these challenges, maintains overall LSE resource adequacy requirements, facilitates CPUC control over LRA costs and provides an incentive for new resources and transmission. The process could work like this:

1. CPUC establishes a benchmark new entrant price based on the cost of a new resource, offset by the value of projected energy sales. This value would form the basis for location resource costs, and could vary by location based on cost differences (emissions offsets, land costs, etc.)
2. CPUC set a price curve for each load pocket by determining demand level at which cost is fully recovered and point of minimum value. Deliverability of resources for load pockets are defined in the price curve.
3. ISO identifies load pockets and qualifying resources within them prior to year-ahead process. (no change from current proposal)
4. Individual LSEs "register" local resources under their control with ISO in year-ahead process. (no change from current proposal)

5. Uncommitted resources within load pockets may offer their capacity as well.
6. ISO determines if participating capacity (registered LSE resources plus offered uncommitted resources) is sufficient to meet minimum criteria, enters into RMR contracts as needed with non-participating resources to meet criteria.
7. Local RA price set based on amount of capacity registered/offered plus RMR capacity within load pocket.
8. LRA price paid to all participating resources, charged to load through RSC. LRA revenues would offset procurement costs for LSEs, and be recovered through transmission pricing.
9. Must offer requirement applies to all participating resources.
10. Any excess capacity obtained for LRA would apply to total system RAR requirement/price on pro rata basis or be reflected in price curve per load pocket.

Impact on "Challenges"

- **Evaluating transmission alternatives** – Cost of LRA would be part of transmission rates. PTOs would have incentive to implement cost effective transmission upgrades.
- **Defining obligation** – Load-based obligation, irrespective of LSE load served.
- **Buyer monopoly** – LSEs receive benefit of resources they control, does not preclude other LSE's participation in load pockets.
- **Free-riders** – all load pays same LRA charges, LSEs who don't have LRA don't receive offset. Non-jurisdictional LSEs that use transmission system also pay share.
- **Small requirements** – LSEs do not need to acquire small bits of LRA.
- **Cost allocation** – Costs allocated to all PTO load equally (could be differentiated by load pocket, but don't need to be).
- **Market power** – Demand curve entrant price sets ceiling for just and reasonable price for all local resources. Cost-based RMR contract remains available if new-entrant price not sufficient.
- **Jurisdictional balance** – FERC retains jurisdiction over transmission and wholesale energy pricing, CPUC establishes local capacity requirements. Balance and operation of resource adequacy process can be overseen by both entities. This is consistent with other regions and has been acceptable to state and federal regulators.

Q&A

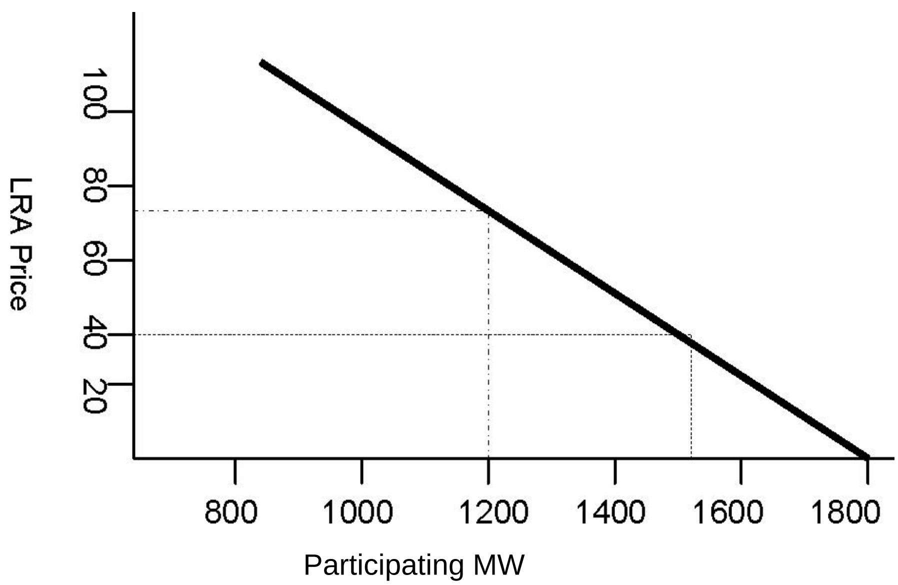
1. Wouldn't this be more costly than current mechanism? LRA costs for committed resources would transfer costs from procurement costs to transmission with no net cost increase. Pricing mechanism would provide price signals for new generation/transmission within load pockets. Uncommitted resources that offer capacity would be paid based on market value, eliminating most RMR contracts.
2. This appears to eliminate LSE responsibility for LRA. Isn't that inconsistent with Phase 1 Decision? LSEs have incentive to obtain LRA resources to offset transmission charges to customers and retain overall LSE-specific RAR. It would probably be necessary to request revision of Phase 1 decision, but revision warranted based on improved mechanism.
3. How would it be possible to implement this in time for 2006 RAR?

The only change from proposed RAR process is development of new entrant prices and demand curves. Simplified proxy could be used for first year based on independent assessment of peaking unit cost and review of ISO's imbalance energy prices and historic gas prices.

4. Does this require development of system-wide capacity market? No. Load pocket resources as defined by ISO and acquired under bilateral arrangement could be registered only for purpose of LRA.
5. How would LD energy contracts fit into this program? They wouldn't, though LSEs that rely on LD contracts for aggregate RAR (to the extent the LD contracts count) would not be required to obtain separate resources to meet LRA.

Hypothetical example

- Annual fixed cost of new entrant in "load pocket x" = $100/kW year
- Estimated market revenue from energy and A/S markets = $30/kW year
- Benchmark capacity cost = $70/kW year
- "Load pocket x" resource requirement (as determined by CAISO) = 1,200 MW
- Zero value level = 150% of requirement



In the above example, 1,200 MW of participating resources would produce a price of $70.00, while 1,500 MW of participating resources would produce a price of $40.00.

(END OF APPENDIX H)

APPENDIX I

RESOURCE ADEQUACY REQUIREMENT

DISCUSSION OF COMPLIANCE ISSUES

The purpose of this paper is to outline principles and where appropriate to propose potential solutions to outstanding issues relevant to specification of the year-ahead and month-ahead reporting and compliance standards for the Resource Adequacy Requirement (RAR) being developed through the CPUC workshops. The paper augments a previous paper related to this subject submitted by the California Independent System Operator (CAISO) dated January 3, 2004.

This paper will cover the following topics:
- Provide a draft template to report capacity that will be used for compliance of the CPUC RAR
- Enforcement of the CPUC RAR related to the year-ahead and month-ahead reporting requirements
- Enforcement of the CPUC RAR related to the actual performance of the resource in CAISO markets
- Forecasting requirements related to measuring compliance
- Existing system energy or Firm Liquidated Damages (LD) contracts

RAR Template

CAISO has developed a draft RAR template (Exhibit 1). This Template would serve as the form that each Load Serving Entity (LSE) would provide to the CAISO to report compliance with its year-ahead or month-ahead reporting requirements. The template provides the information needed by the CAISO to validate compliance to the reporting requirements, to support audits of the information supplied, and to provide information to the CAISO to validate that the capacity is made available to the CAISO market when required.

In addition to developing a template, the CAISO proposes the following requirements related to completion and submission of the year-ahead and month-ahead RAR template:
- Templates must be submitted to the CAISO and to the CPUC by 5:00 pm Pacific Time on or before the last CPUC Business Day of the month that the report is due. (For example, September 30, 2006 falls on a Saturday so the report will be required to be received by the CPUC and the CAISO by 5:00 pm Pacific Time on Friday, September 29, 2006.)
- The LSE is responsible to provide factually accurate information in its year-ahead and month-ahead reports. Any factual error in these filings will be subject to sanction, as determined by the CPUC.

Enforcement of the CPUC RAR related to the year-ahead and month-ahead reporting requirements

The CPUC has imposed the year-ahead and month-ahead reporting requirement and, to the maximum extent practicable, should be enforced by the CPUC. The CAISO is available to assist the CPUC in validating the RAR template forms and to identify any apparent violation to the CPUC for possible sanction as deemed appropriate by the CPUC. Examples of violations for which some objective penalty should apply include, but are not limited to, late submission of a report, factually inaccurate information submitted in a report, and any report submission that identifies a failure to meet the RAR requirements as ordered by the CPUC.

The CPUC/CAISO must review the RAR template forms submitted by LSE's for completeness and to assure that adequate capacity is provided based on the information submitted. The proposed template does not provide for validation of capacity contracts but provides contract reference numbers to relate each resource with the relevant capacity contract. An additional compliance audit should be performed by some entity to assure that the contracts used to meet the RAR fulfill the contractual requirements as ordered by the CPUC.

As noted above, the CAISO contemplates referring violations of an LSE's reporting and procurement obligations to the CPUC for possible sanctions. The CAISO does not currently propose any specific form or level of sanction. However, the CAISO has consistently maintained that financial penalties for non-compliance are a necessary backstop and should be appropriately calibrated to discourage non-compliance with the RAR.

Enforcement of the CPUC RAR related to the actual performance of the resource in the CAISO market

The capacity used to meet the CPUC RAR must be available to the CAISO market as required by contract with the LSE's and as required by the CPUC RAR. The RAR template form identifies the specific Resource or Interchange ID for resources and can be used to determine if the capacity satisfied the RAR availability obligations. The CAISO will identify all instances where capacity identified to meet the RAR for an LSE on its template form failed to make itself available as required.

Failure to provide capacity when required will be subject to sanction. There are, at least, two basic mechanisms to impose such sanctions and a potentially many permutations in their implementation: (1) the bilateral contracts or (2) the CAISO Tariff. Each mechanism presents fundamentally different enforcement procedures and venues. The workshop participants should address these mechanisms, as well as potentially others, to inform the CPUC by defining their features, advantages and disadvantages.

Forecasting requirements related to measuring compliance

In order to meet its RAR, each LSE must provide sufficient capacity to meets its forecast peak load for each month. There must be no ambiguity regarding the specific load forecast value that each LSE will be held accountable to meet for each month. In order for CAISO to validate compliance that each LSE met its individual RAR, the specific value for the forecast must be validated by the CEC or some entity other than the LSE. This validated forecast must be made available to the CAISO on or before the date that the related year-ahead or month-ahead template is due to be submitted to the CPUC and the CAISO.

Existing system energy or Firm LD contracts

The RAR template includes existing system energy or Firm LD contracts to the extent the CPUC authorizes their limited use during a transition period. Similar to other resources, all such contracts will be given a Resource ID. The CAISO continues to attempt to develop compliance procedures that minimize the threat of double counting of capacity inherent in allowance of system energy. At a minimum, it is contemplated that the physical resources used to satisfy the contractual energy delivery obligation must identify the Resource ID in the CAISO's Day-Ahead scheduling process.

Exhibit 1

CPUC Resource Adequacy Template

Draft
Version 1.0

LSE: ______________________________
Completed By: ______________________________
Title: ______________________________
Date: ______________________________
Total Capacity (100%+15%): ______________________________
Filing: Annual ____ Month Ahead ____ (Check One)

Peak Customer Load: ______________________________
Coincidence Factor: ______________________________
Losses: ______________________________
UFE: ______________________________
Minimum Capacity (90%+15%): ______________________________
RAR Month: ______________________________

Resources in ISO Control Area

Resource ID	Qualified Capacity	Contract Capacity	RAR Effective Start Date	RAR Effective End Date	Reference Number	Minimum Hours/	Counterparty	Scheduling Coordinator

Imports

Interchange ID	Qualified Capacity	Contract Capacity	RAR Effective Start Date	RAR Effective End Date	Reference Number	Available Hours	Counterparty	Scheduling Coordinator

Resources Under Construction

Resource ID	Qualified Capacity	Contract Capacity	RAR Effective Start Date	RAR Effective End Date	Reference Number	Minimum Hours/	Date of Commercial Operation	Counterparty	Scheduling Coordinator

Existing Liquidated Damages Contracts

Congestion Zone	Contract Capacity	RAR Effective Start Date	RAR Effective End Date	Reference Number	Minimum Hours/	Counterparty	Scheduling Coordinator

Total Contract Capacity (sum of values in tables shown above)

Type of Contract Capacity	Contract Capacity
Resources in ISO Control Area	
Imports	
Resources Under Construction	
Existing Liquidated Damages Contracts	
Total	

Comments:

RAR Template
Draft
Version 1.0

The Resource Adequacy Template is created to assure that each Load Serving Entity ("LSE") has contracts for sufficient capacity to meet its Resource Adequacy Requirement as required by CPUC Decision 04-10-035. The template must be completed and submitted according to the schedule provided by the CPUC. Reports must be submitted by the respective due date to:

- California Public Utilities Commission mailbox: rarfilings@cpuc.ca.gov (not an actual mailbox - used here for illustration purposes)
- California ISO mailbox: rarfilings@caiso.com (not an actual mailbox – used here for illustration purposes)

The template form requires the LSE to identify the specific resources that will supply capacity to meet its RAR. The sum of all valid "Contract Capacity" values contained in the completed template will be considered the total quantity of capacity that an LSE has acquired to apply toward its RAR.

The same template will apply to the Year-Ahead showing and for the Month-Ahead showing. All fields are required to be completed for the Year-Ahead and Month-Ahead showings unless explicitly stated otherwise below. An explanation of the fields to be completed follows.

Heading

LSE – The legal name of the Load Serving Entity
Completed By – The name of the person responsible for the accuracy and completeness of the form
Title – The title of the person responsible for the accuracy and completeness of the form
Date – The date the form is completed
Peak Customer Load – The monthly specific peak customer load for the Load Serving Entity following the forecasting requirements and any subsequent adjustments to the forecasting methodology or the specific forecast as may be amended by the California Energy Commission (CEC)
Coincidence Factor – The LSE monthly specific Coincidence Factor determined by the (CEC)
Losses – The quantity of additional capacity that the LSE must acquire to compensate for losses
UFE – The quantity of additional capacity that the LSE must acquire to compensate for UFE
Total Capacity – The monthly specific peak customer load modified by the coincidence factor plus additional capacity required for losses and UFE is

determined and then multiplied by 115% to determine the total required capacity for the specific month.
Minimum Capacity – 90 percent of the total capacity as defined above. This field is required to be completed in the Annual filing but not in the Monthly filing.
Filing – Identify if this is an Annual filing or a Monthly filing by checking the appropriate box
RAR Month – Identify the specific RAR month represented by this form. Note: a separate CPUC Resource Adequacy Template form must be completed for each RAR month. Also note that a Month -Ahead showing is required for each calendar month and a Year-Ahead showing is required for each of the five RAR peak months as defined by the CPUC.

> Note: The most efficient method to reduce complexity of validating RAR compliance is that all RAR contracts should be on a calendar month basis. Without such a requirement, each line in the CPUC Resource Adequacy Template would represent a complete and unique capacity transaction. The LSE can represent any specific contract quantity changes that occur during the RAR Month by completing another line in the template and by noting the Effective RAR Start Date and Effective RAR End Date for each change.

<u>Resources in the ISO Control Area</u>

Resource ID – The CAISO Resource ID
Qualified Capacity – The quantity of total qualified capacity as defined by the CAISO for the purposes of RAR
Contract Capacity – The quantity of capacity that the LSE has under contract and that will be counted toward its requirement for that RAR Month. Note: the Contract Capacity amount cannot exceed the Qualified Capacity amount for the relevant resource(s) after application of deliverability screens. Also note that any changes to Contract Capacity during the RAR month must be identified in a separate line entry
Effective RAR Start Date – The first date during the RAR month when the Contract Capacity quantity becomes available to the LSE
Effective RAR End Date – The last date during the RAR month when the Contract Capacity quantity is available to the LSE
Reference Number – LSE specified number that identifies the relevant contract(s). This information will be used to identify supporting documentation during compliance audits
Minimum Hours – Identify the minimum number of hours that the resource is available to provide the Contract Capacity during the RAR month
Counterparty – The legal name of the contract counterparty
Resource SC – The name of the Scheduling Coordinator for the resource.

Imports

Interchange ID – The CAISO Interchange ID
Qualified Capacity – The quantity of total qualified capacity available to the specific LSE at the specific interchange intertie, as defined by the CAISO for the purposes of RAR
Contract Capacity – The quantity of capacity that the LSE has under contract and that will be counted toward its requirement for that RAR Month. Note: the Contract Capacity amount cannot exceed the Qualified Capacity amount. Also note that any changes to Contract Capacity during the RAR month must be identified in a separate line entry
Effective RAR Start Date – The first date during the RAR month when the Contract Capacity quantity becomes available to the LSE
Effective RAR End Date – The last date during the RAR month when the Contract Capacity quantity is available to the LSE
Reference Number – LSE specified number that identifies the relevant contract(s). This information will be used to identify supporting documentation during compliance audits
Available Hours – Identify the hours during the day that the import is available to provide the Contract Capacity during the RAR month
Counterparty – The legal name of the contract counterparty
Resource SC – The name of the Scheduling Coordinator for the resource.

Resources Under Construction

Resource ID – The CAISO Resource ID (or Resource Name if no CAISO Resource ID)
Qualified Capacity – The quantity of total qualified capacity as defined by the CAISO for the purposes of RAR
Contract Capacity – The quantity of capacity that the LSE has under contract and that will be counted toward its requirement for that RAR Month. Note: the Contract Capacity amount cannot exceed the Qualified Capacity amount. Also note that any changes to Contract Capacity during the RAR month must be identified in a separate line entry
Effective RAR Start Date – The first date during the RAR month when the Contract Capacity quantity becomes available to the LSE. Note: this date may not be sooner than the date of Commercial Operation as defined by CPUC Decision 04-10-035.
Effective RAR End Date – The last date during the RAR month when the Contract Capacity quantity is available to the LSE
Reference Number – LSE specified number that identifies the relevant contract(s). This information will be used to identify supporting documentation during compliance audits

Minimum Hours – Identify the minimum number of hours that the resource is available to provide the Contract Capacity during the RAR month
Date of Commercial Operation - The status of a Generating Unit at a Generating Facility that has completed construction, interconnected to the applicable distribution or transmission system, completed all start-up, Commissioning and performance testing, received final approvals from the applicable distribution or transmission provider, and commenced scheduling or bidding for the sale of electricity in the forward market. The establishment of contracts and agreements between an LSE and an energy supplier or developer will have no bearing or affect on the determination of Commercial Operation.
Counterparty – The legal name of the contract counterparty
Resource SC – The name of the Scheduling Coordinator for the resource.

Existing Liquidated Damages Contracts

Congestion Zone – The congestion zone where the capacity will be delivered. This field can contain more than one congestion zone if necessary. If capacity can be delivered in all CAISO congestion zones, use "CAISO Control Area" as the input
Contract Capacity – The quantity of capacity that the LSE has under contract and that will be counted toward its requirement for that RAR Month. Note: any changes to Contract Capacity during the RAR month must be identified in a separate line entry
Effective RAR Start Date – The first date during the RAR month when the Contract Capacity quantity becomes available to the LSE
Effective RAR End Date – The last date during the RAR month when the Contract Capacity quantity is available to the LSE
Reference Number – LSE specified number that identifies the relevant contract(s). This information will be used to identify supporting documentation during compliance audits
Available Hours – Identify the hours during the day that the LD contract is available to provide the Contract Capacity during the RAR month
Counterparty – The legal name of the contract counterparty
Resource SC – The name of the Scheduling Coordinator for the resource.

Comments – Any additional comments that may be relevant.

(END OF APPENDIX I)

APPENDIX J

RESOURCE ADEQUACY REQUIREMENT

PRELIMINARY DISCUSSION OF REPORTING AND COMPLIANCE

General Note:
The October 28 CPUC order refers to "forward commitment obligations" in the context of LSEs annual and month-ahead compliance showings. Consider using this terminology, throughout, in place of "RAR" when speaking in the context of annual and month-ahead LSE compliance showings.

The purpose of this paper is to outline preliminary principles and outstanding questions relevant to the specification of year-ahead and month-ahead reporting and compliance standards for the Resource Adequacy Requirement (RAR) being developed through the CPUC workshops. The previous CPUC decisions have established certain overarching requirements. These include; a year-round obligation for each LSE to have acquired 115% capacity committed to serving its load, year-ahead and monthly compliance reports, etc.

The related RAR topics and workshop dates follow:

January 12, 2005 Workshop
- Topic 12 – Year-ahead and month-ahead obligations
- Topic 20 – Month ahead filing requirements and data access rights
- Topic 21 – Penalties and sanctions

January 13, 2005 Workshop
- Topic 17 – Load forecast filing requirements, historic load data, adjustment for energy efficiency and demand response.
- Topic 18 – Resource tabulations demonstrating that reserve requirements for hours with loads greater than 90% of monthly peak are met
- Topic 19 – Review process to assure that load forecasts comply with requirements, that sufficient eligible and deliverable resources are designated; that errors and deficiencies are corrected; and that aggregate resources meet the aggregate requirement

Compliance

The following general principles are offered regarding compliance rules. The first step in developing a plan for verifying compliance is to assure that the obligations are spelled out in complete detail, and that the reporting requirements parallel those obligations.

1) Obligations for reporting and performance should be clear and complete, with the first priority being assurance of resource adequacy for each LSE and, more generally, for the system as a whole.

2) Information reported by each LSE should be sufficient to allow objective verification of compliance with all specified RAR obligations (i.e., to the maximum extent possible, the verification process should be reduced to comparing filed reports or actual performance to a check-list).[65]

3) Obligations at each time horizon (year-ahead and month-ahead) must be fully specified. This means that an objective standard is necessary against which each obligation can be compared. For example, each LSE must certify in the year-ahead and month-ahead compliance filings that the necessary amounts of deliverable resources will be either scheduled or offered as energy, ancillary services or for unit-commitment in the CAISO processes during the Delivery Period, except of in the case of Forced Outage, and in accordance with the CAISO's tariff. Detailed templates for the year-ahead and month-ahead compliance filings will be developed to precisely specify what information is required.

4) Financial penalties for non-compliance are a necessary backstop, and should be based on entirely objective information. To encourage compliance with forward commitment obligations and to avoid free-rider-ship, penalties should be equal to the greater of a) any demonstrable costs of a deficiency in meeting the RAR on either a year-ahead or month-ahead basis, including the forecasted value/cost of lost load ("VOLL"), or b) some amount determined necessary to encourage year-ahead and month-ahead compliance. This same backstop principle must also apply with respect to failures to make forward committed resources available in CAISO's spot markets.

5) Each LSE must file all required information on time. If any extensions or waivers are to be considered, then conditions should be specified for when and how an LSE may seek a time-bounded extension of a reporting requirement, and objective criteria should be developed for responding to such requests.

<u>Reporting Obligations</u>

The following details must be specified to adequately define reporting requirements and consequences for non-compliance with load forecasting obligations.

[65] Objective measures are consistent with the October 28 order, which stated "We intend to provide sufficient clarity through guidelines and rules that the review process should ultimately become a simple checklist. " Section 3.9, page 43.

1) The documentation that each LSE is required to maintain in support of any filed report should be specified, and such documentation should be made available for audit by the entity responsible for verifying compliance with the associated standards.

2) Load forecast should specify methodology in sufficient detail to allow verification that the effects of losses, UFE, demand response, energy efficiency and distributed generation are reflected in the hourly forecast.[66] Comprehensive rules specifying the required output (e.g., forecast results by hour) and documentation (e.g., assumptions, methodology, equations, data) are necessary to verify compliance. There should be no ambiguity or subjective judgment required. These include the interplay between the LSE initial forecast and the adjustments made by the CEC to establish the LSE resource adequacy obligation in both year-ahead and month-ahead compliance filings.

3) The methodology for specifying coincidence factors used in developing LSE forecasts must be sufficiently detailed to allow LSEs to translate LSE specific load forecast into hourly obligations. Reporting requirements must provide sufficient details to validate that LSEs have properly applied the specified coincidence adjustments.

4) Requirements for associating contract capacity with physical resources must be spelled out, and the obligation of resources to be available unless prevented by a Forced Outage must be specified[67].

5) The October 28 order specifies that LSEs must acquire a "mix of resources that are within 10% of their maximum contribution to monthly system peak." The precise hours for which a resource adequacy obligation applies must be objectively defined for each LSE in relation to the overall resource adequacy requirements. Appendix 1 explores some of the issues.

[66] The October 28 decision states that the Commission "will establish a tracking system that compares forecasts with actual loads and creates penalties for excessive deviations "but later requests that the CEC should bring "obvious discrepancies" to the Commission's attention well in advance of the September 30 compliance filings. "If patterns of systematically low load forecasts are revealed by CEC analyses, we will take appropriate action at that time." What is required of the Phase 2 workshops with respect to penalties for load forecast error?

[67] It will be necessary to develop criteria to determine when a resource with a forced outage is of sufficient duration to make it a "Scheduled" outage for RAR purposes.

Outstanding Issues

1) The specification of the delivery period should address the following questions: (1) What obligation will LSEs have to schedule or bid the designated resources during the peak hours of the relevant month? (2) What obligation will LSEs have to schedule or bid the designated resources during the balance of the relevant month's hours?

2) Clear rules must be established for the year-ahead and month-ahead attribution of deliverable capacity from specific resources to meet an LSE's specific resource adequacy obligations. This includes making clear that the individual resources supporting any LSE's obligation met by a contract or by a portfolio must be identified in the annual and month-ahead compliance filings. Suppose that two LSEs rely on three separate contract portfolios, and that these contract portfolios rely on ten physical generating units, with some resources in only one portfolio, others in two and some in all three. An objective basis for assigning any deficiency must be defined.. This objective basis should stem from LSEs contracting for capacity that is fully dedicated to the CAISO control area in each RAR hour of the relevant delivery period. LSEs' compliance filings will provide the information necessary for an independent review and objective finding that there are no redundant commitments of generating capacity internal to the CAISO control area or with respect to allocated inter-control area transmission capacity (i.e., that there is no "double-counting" of capacity within an LSE portfolio or across all LSEs' portfolios of forward-contracted capacity).

3) CPUC decision requires LSEs to "acquire a mix of resources capable of satisfying the number of hours for each month that their loads are within 10% of their maximum contribution to monthly system peak." Thus, the LSE and/or resource owner must have the requisite capacity available during those designated hours within the relevant delivery period. The rules for when LSE's contracted capacity resources must be bid or scheduled into the CAISO should include the following:

    a. Seller represents and warrants to buyer that seller has ownership of or demonstrable exclusive right to the "system" capacity supporting Seller's contract quantity obligations under the transaction, and that such resources are either located in [delivery region] or have firm transmission to [delivery region].
    b. "System" capacity[68] refers to one or a number of individual resources that comprise a certain amount of certified or qualified capacity for purposes of resource adequacy and have specified deliverability.

[68] "System" capacity refers to a list of one or more individual generating units that are located within the CAISO's control area; as distinguished from the term

c. Seller commits to buyer the right to count the contract quantity from seller's "system" toward the forward commitment obligations of buyer's resource adequacy requirements during the Delivery Period.
d. "Delivery Period" refers to the hours established by the PUC during which capacity satisfying resource adequacy requirements must be available.
e. Seller shall either schedule or offer the available contract quantity as energy, ancillary services or for unit-commitment in the CAISO's process or procedure at the delivery point during the delivery period.

4) If an energy-limited resource is not required to serve an LSE's load or reserve requirement but is still required to bid, and is then dispatched to meet another LSE's deficiency, how will the initial LSE's increased risk of a subsequent deficiency due to the "pooled" use of its energy limited resource be addressed? How will "deposits" and "withdrawals" to the "pool" be accounted for?

5) The CPUC October decision establishes a reporting obligation in the month-ahead compliance showing by LSEs to allow that some specific actions may be taken to resolve deficiency prior to DA. What actions are allowed? For example, the LSE submits its month-ahead compliance late; would there be a daily penalty/sanction? Versus, the LSE's compliance filing is found to be short of its forward commitment obligation. In the latter case, a meaningful penalty/sanction should be assessed after the year-ahead and/or Month-ahead compliance filings if the LSE is found to be short of meeting its forward commitment obligations.

6) Should there be enforcement beyond the monetary penalties/sanctions referenced above? For example, would LSEs found short in the year-ahead or month-ahead compliance showing be set for first curtailment in the relevant delivery period? If so, how would the CAISO implement such a curtailment procedure on a LSE-specific basis? The ISO could not give a MW curtailment directive to the applicable UDC without potentially affecting other LSEs within the UDC footprint that showed themselves to be resource adequate in the annual and month-ahead compliance showings. Instead, penalties/sanctions should be applied both with respect to spot market compliance and forward market compliance filings. Applying penalties/sanctions in the spot market **alone** may not be sufficient to encourage the forward market commitment of deliverable capacity.

"System Resources" that is defined in the CAISO tariff and that refers to resources located outside of the CAISO's control area.

APPENDIX 1

CAPACITY REQUIREMENT

The October order states that "we will require that LSEs acquire a mix of resources capable of satisfying the number of hours for each month that their loads are within 10% of their maximum contribution to monthly system peak." (page 17)[69]

Clear rules for how this requirement defines the RA requirement for each LSE must be developed. As written, it appears that the hours for which the RA requirement applies differ depending on the load profile of the LSE relative to the system load profile.

Example: Assume "LSE 1" has a 100 MW peak that is coincident with the system peak, and is projected to have load exceeding 90 MW (i.e., load within 10% of maximum contribution to system peak) in 10 hours. This means that this LSE 1 must have 115 MW (i.e., 115% of 100 MW) of qualified capacity for 10 hours.

Now assume that "LSE 2" has a non-coincident peak of 100 MW, and a contribution to the system peak of 50 MW. This LSE 2's RA requirement is based on 57.5 MW (i.e., 115% of 50 MW). If LSE 2's load exceeds 45 MW in 180 hours in the month, then LSE 2 must have 57.5 MW of qualified capacity for180 hours during the month.

We believe that this approach to defining the hours in which the requirement is specified should be revisited, and that a single set of hours related to the timing of the system coincident peak should define the requirement for all LSEs. Otherwise significant and possibly insurmountable problems will arise with the compliance check.

In any event, all the details regarding when and how the availability hours are specified must be developed. Assuming that a single set of availability hours applies to all LSEs, one approach may for the ISO to publish the "availability hours" for the Operating Day on a daily basis as part of the Public Market Information (PMI) in an advisory manner (e.g., by 6:00 p.m. on August 19, 2007 the ISO would announce HE 1400 to HE 2000 of August 21, 2007 as availability hours, subject to revision by 5:00 a.m. on August 20, 2007). The obligation would then apply to those hours. Any additional hours for which the forward committed resource may have to be "ON" due to its minimum run time would not be considered towards satisfying the LSE's obligation to make the forward committed resource available for the month.

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[69] There is no "maximum" contribution to the system peak. Since there is only one monthly system peak, there is only one MW level of contribution to that peak by each LSE.

Finally, the above 90% of the peak criterion may work effectively when applied to a system-wide RA obligation. However, the hours associated with the local RA obligation, will likely differ. For locational RA obligations, the number of hours may be higher or lower depending on the load duration curve in the load pocket, local generation within the load pocket, and the local transmission constraints. This is appropriate because the voltage and thermal transmission constraints that should define the load pockets also limit access to deliverable capacity that might otherwise be available to supply loads that differ from the system-wide average load duration curve.

(END OF APPENDIX J)