Decision 07-06-029 June 21, 2007

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program.	Rulemaking 05-12-013 (Filed December 15, 2005)

OPINION ON PHASE 2 – TRACK 1 ISSUES

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1. Summary

Taking another step towards full implementation of the Commission's resource adequacy (RA) program, this decision adopts local procurement obligations for 2008 that are applicable to Commission-jurisdictional electric load-serving entities (LSEs). These local procurement obligations are based on a study of local capacity requirements (LCRs) for 2008 that was performed by the California Independent System Operator (CAISO) with stakeholder input. Other key determinations made herein include the following:

- The CAISO's stated need for access to adequate generation within certain defined transmission-constrained zones, particularly in Southern California, is addressed by adopting a jointly proposed "Path 26 Counting Constraint." This approach is approved in lieu of the addition of a separate and explicit Zonal RA Requirement to the RA program.

- Addressing concerns regarding the LCR study process administered by the CAISO, the Commission provides for a workshop that would address scheduling issues and ideas for greater transparency.

- The Commission reiterates support for the inclusion of probabilistic analysis in the LCR study in order to assure economically efficient decisions regarding the local area procurement requirements.

- Interruptible and emergency demand response (DR) resources will continue to qualify towards meeting LSE procurement obligations pending review of the means of coordinating the CAISO's operational needs and the DR and RA programs in Rulemaking (R.) 07-01-041, the current DR proceeding.

- The Commission adopts an Energy Division proposal to coordinate the Local RA program for 2008 and the CAISO's backstep procurement process.
- The Commission adopts Energy Division proposals for rounding resource procurement obligations and for counting the value of new wind resources.
- The Commission addresses a proposal to establish a workshop process to develop a standard contract and associated generator obligations.

2. Background

2.1. Context for this Decision

Through a series of decisions summarized in the table below, the Commission has established RA policies and regulations to ensure that there is adequate, cost-effective investment in electric generation capacity for Californians served by investor-owned utilities (IOUs) and that such capacity is made available to the CAISO when and where it is needed for reliable transmission grid operations.

Principal Resource Adequacy Decisions

Decision/ Proceeding	Summary
Decision (D.) 04-01-050/ Rulemaking (R.) 01-10-024	In conjunction with the adoption of a long-term procurement regulatory framework for the three major California IOUs, the Commission adopted a policy of establishing near-term forward procurement obligations applicable to all LSEs, including electric service providers (ESPs) and community choice aggregators (CCAs). This LSE-based forward procurement policy was premised on a planning reserve margin (PRM) requirement targeted to be phased in and fully effective by January 2008. The PRM, which had been preliminarily set at 15% (see D.02-10-062 and D.02-12-074), was modified to a 15%-17% requirement to reflect "lumpiness" in resource procurement. The primary procurement obligation is that LSEs must demonstrate acquisition of 90% of the capacity needed to meet their forecast peak load, plus the PRM, on a "year-ahead" basis for the following May through September.
D.04-07-028/ R.04-04-003	Responding to the CAISO's increasing need to manage congestion and address reliability issues in Southern California, and in particular the operational difficulties for the CAISO and reliability concerns for the summer of 2004, the Commission modified prior orders to make clear that reliability is not only the CAISO's job. It is also a utility responsibility to procure resources necessary to meet its load system-wide and locally.
D.04-10-035/ R.04-04-003	Concurring with concerns raised by Governor Arnold Schwarzenegger regarding grid reliability in the near term, the Commission accelerated implementation of the 15-17% PRM requirement from January 2008 to June 2006. It also provided definition and clarification regarding the RA policy framework. Key elements of the decision included load forecasting protocols, resource counting conventions, month-ahead compliance showings by LSEs in addition to year-ahead showings, and a policy that resources that qualify for RA compliance purposes should be obligated to bid into the CAISO's day-ahead market if not scheduled by the LSE.
D.05-10-042/ R.04-04-003	The Commission ordered the implementation of what has come to be known as the "system" RA program beginning in June 2006 and stated its intention to establish Local RA procurement obligations beginning in 2007. It also addressed several RA program implementation issues, including the nature of the RA obligation (monthly system peak), the role of the California Energy Commission (CEC) in reviewing and adjusting LSE load forecasts, coordination of the RA program and CAISO operations, load forecasting and resource counting issues not resolved in earlier decisions, standard RA contract elements, the phase-out of the ability to count non-unit specific contracts for RA showings, the "must-offer obligation" (MOO) of RA resources to be available to the CAISO, and penalties for an LSE's failure to meet RA procurement obligations.

D.06-02-007/ R.04-04-003	In response to a petition for modification of D.05-10-042, the Commission removed a prohibition on reselling and re-trading import capacity rights.
D.06-04-040/ R.04-04-003	In response to applications for rehearing of D.05-10-042, the Commission modified D.05-10-042 to emphasize that the RA program in place for 2006-2008 is transitional and to clarify that the MOO provision to be included in RA contracts is an independent, RA-based requirement that does not attempt to change or alter the current Federal Energy Regulatory Commission (FERC)-imposed MOO. Rehearing of D.05-10-042, as modified, was denied.
D.06-06-064/ R.05-12-013	The Commission established local procurement obligations for 2007 based on a 2007 LCR study by the CAISO, and set the stage for establishing local procurement obligations in future years. The decision addressed various local RA policy and implementation issues including LCR study methodology, allocation of LCRs to Commission-jurisdictional LSEs, aggregation of local areas for compliance purposes, the compliance filing process, coordination with the CAISO's Reliability Must Run (RMR) designations, market power, waivers, and penalties for non-compliance.
D.06-07-031/ R.05-12-013	This decision addressed certain RA policy issues to establish clearer expectations among market participants regarding how contracts for RA resources will count towards meeting LSEs' procurement obligations. Among other things it adopted protocols for forced and scheduled outages and it refined the Commission's definition of the essential elements of an RA capacity product that can be readily traded.
Resolution No. E-4017	Approved a citation program under the administration of the Energy Division for enforcing compliance with certain RA filing requirements.
D.06-12-037 R.04-04-003	In response to various petitions for modification of D.05-10-042, the Commission modified D.05-10-042 to (1) require that RA-qualified firm liquidated damages import contracts specify a delivery point at an interconnection with the CAISO control area or a CAISO scheduling point, (2) exempt certain import contracts from the general requirement that RA resources be available to the CAISO in real time, and (3) make minor clarifying wording changes.

Today's decision completes Track 1, the first of three procedural tracks that were designated for Phase 2 of this proceeding.[1] It represents another step

[1] See *Assigned Commissioner's Ruling and Scoping Memo for Phase 2* (Phase 2 Scoping Memo), issued December 22, 2006. The Phase 2 Scoping Memo designated the following issues for consideration in Track 1: (a) local RA issues including LCR study

Footnote continued on next page

in the series of orders listed above that, collectively, constitute the evolving RA program. In a future decision in this proceeding we will address major policy questions regarding the long-term RA program as well as proposals to extend the RA program to all Commission-jurisdictional LSEs.

2.2. The Track 1 Record

Pursuant to the schedule and procedure established by the Phase 2 Scoping Memo, 15 parties or party coalitions filed proposals for Track 1 issues on January 26, 2007. The Commission's Energy Division facilitated workshops on these topics on February 8, February 20, February 21, and March 8, 2007. At the request of the Energy Division staff, five parties or party coalitions submitted post-workshop refinements to their proposals on March 22, 2007.

The CAISO posted its Local Capacity Technical Analysis for 2008 (2008 LCR Study) on its website on March 9, 2007 and served notice of the posting on March 13, 2007. On March 21, 2007, the CAISO convened a stakeholder meeting at its Folsom headquarters to address the 2008 LCR study. On April 4, 2007, the CAISO filed an update to the 2008 LCR Study.

On March 30, 2007, the Energy Division issued a report on Track 1 issues (Staff Report). The Staff Report was incorporated into the record by an Administrative Law Judge's (ALJ) ruling issued on April 6, 2007. This decision generally follows the outline of the Staff Report.

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methodology and implementation rules, (b) probabilistic LCR assessments, (c) zonal RA, (d) DR program impacts and dispatch, (e) coordination of the RA program with the CEC load forecasting process, (f) coordination of the RA program with applicable backstop mechanisms, (g) implementation of Assembly Bill (AB) 1969, and (h) minor implementation issues.

In addition to the filings described above, the Track 1 record includes post-workshop comments and replies filed April 6 and April 20, 2006, respectively. Track 1 was submitted for decision on the latter date.

The following table indicates the parties and party groups that filed proposals and/or comments in Track 1.

PARTIES FILING TRACK 1 PROPOSALS AND/OR COMMENTS

Filing Party or Parties	Short Title for Party or Party Group	Track 1 Proposals (1/26/07)	Post-Workshop Proposals (3/22/07)	Post-Workshop Comments (4/06/07)**	Replies to 4/06/07 Comments (4/20/07)
Aglet Consumer Alliance	Aglet	X		X	X
Alliance for Retail Energy Markets	AReM	X		X	X
California Independent System Operator	CAISO	X		X	X
California Large Energy Consumers Association and California Manufacturers & Technology Association	CLECA/ CMTA	X		X	
California Municipal Utilities Association	CMUA			X	X
Calpine Corporation	Calpine	X		X	X
Capacity Market Advocacy Group (SDG&E, Edison Mission Energy, Mirant Corporation, SCE, Constellation Energy Commodities Group, FPL Energy, and NRG Energy, Inc.)	CMAG	X			
Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc. (Constellation); Mirant California LLC, Mirant Delta LLC, Mirant Potrero LLC (Mirant); and Reliant Energy Inc. (Reliant). (Reliant did not join in the April 20, 2007 reply comments.)	Constellation, et al	X	X	X	X
Division of Ratepayer Advocates	DRA	X	X	X	X
Independent Energy Producers Association	IEP	X		X	
NRG Energy, Inc.	NRG				X
Pacific Gas and Electric Company	PG&E	X		X	X
Pilot Power Group, Inc.	Pilot Power			X	
San Diego Gas & Electric Company	SDG&E	X		X	X
Sempra Energy Solutions LLC	SES		X		
Sempra Global	Sempra Global	X		X	X
Southern California Edison Company	SCE	X		X	X
The Utility Reform Network	TURN	X		X	X
Western Power Trading Forum	WPTF	X			
CAISO, PG&E, SDG&E, SCE, and TURN (Path 26 Counting Constraint)	Joint Parties		X	X	X

Filing Party or Parties	Short Title for Party or Party Group	Track 1 Proposals (1/26/07)	Post-Workshop Proposals (3/22/07)	Post-Workshop Comments (4/06/07)**	Replies to 4/06/07 Comments (4/20/07)
Calpine; Coral Power, LLC; Constellation; J. Aron & Company; PG&E; Strategic Energy, LLC; AReM; WPTF; and Mirant (Standard Contract and Associated Generator Obligations)	Calpine, et al.		X		

* Post-workshop proposals submitted by DRA, Joint Parties and Calpine, et al. were filed. Those submitted by Constellation et al. and SES were served but not filed.

** The California Department of Water Resources (CDWR) filed comments on May 10, 2007 pursuant to authorization by the ALJ.

3. Zonal Capacity Requirements

3.1. The Need for Zonal RA Procurement

In Phase 1 of this proceeding the CAISO reported that it had identified a need to establish "zonal" procurement obligations to supplement the system and local obligations being established by the Commission. (D.06-06-064, pp. 31-32.) D.06-06-064 provided that the question of whether and how to establish zonal capacity requirements would be taken up later in the proceeding. (*Id.*) The Phase 2 Scoping Memo determined that the topic should be addressed in Track 1, and that the CAISO and other parties should present proposals for Zonal RA. (Phase 2 Scoping Memo, p. 9.) The Phase 2 Scoping Memo also asked parties to address "whether the CAISO's zonal needs necessarily require a Commission–imposed Zonal RAR, analogous to System RAR and Local RAR, or whether the CAISO's zonal needs can be satisfied through an alternative structure." (*Id.*)

In its January 26, 2007 proposal, the CAISO stated that the justification for identifying and meeting local capacity needs—existing transmission constraints preclude reliance solely on imported energy to serve load and comply with desired reliability performance standards in the constrained load pockets—applies equally at the zonal level. Identifying two zones in California, NP 26 and

SP 26,[2] the CAISO stated that these zones are nothing more than larger load pockets since the transmission capacity into each zone by itself is insufficient to satisfy demand and identified operating requirements.

The CAISO explained that the reliability concern to be resolved by a zonal requirement is the ability of the CAISO Controlled Grid to withstand the zone's single largest contingency. It further explained that "apart from a change in transmission topography the contingency could never be resolved without resort to firm load shedding in the absence of physical capacity, whether in the form of demand response or generation." (CAISO proposal, p. 18.)

Four components of the CAISO's preferred methodology for determining zonal capacity requirements are summarized below:

> Forecasted load. The CAISO states that use of a "1-in-5 year peak forecast" is required under its Grid Planning Standards when conducting regional studies, and it asserts that a 1-in-5 standard is the minimum that should be used for zonal RA requirements. The CAISO anticipates using coincident zonal load forecasts prepared by the CEC.
>
> Import capability. The CAISO proposes an import capability calculation that maximizes the quantity of imports into a zone. The calculation starts with the aggregate transfer capability from outside the CAISO control area into each zone that is calculated as part of the existing import capacity allocation process, and also includes import capacity between CAISO zones over Path 26. The CAISO notes that it will be necessary to coordinate the import allocation process with the zonal requirement. The CAISO further notes that

[2] Path 26 is composed of transmission lines between northern and southern California. The two constrained zones identified by the CAISO are the electrical footprint north of this path (NP 26) and the electrical footprint south of it (SP 26).

in the case of SP 26, the proposal does not assess specific changes to flows on individual branch groups.

Generation outages. While the CAISO generally does not permit planned outages during peak demand periods, historically there have been a small number of such outages that are unavoidable. The CAISO estimates generator outages by examining historic outage data on peak summer conditions at hour-ending 1600. The CAISO notes that including an outage component in the zonal methodology does not constitute double-counting of outages in relation to the PRM.

Single largest contingency. The CAISO determined that the single largest contingency for SP 26 is the loss of 2,000 megawatts (MW) related to the loss of the Pacific DC Inter-tie. For NP 26 the largest single contingency is the loss of a Diablo Canyon Unit at 1,160 MW.

Based on these four components of zonal capacity requirements analysis, the CAISO estimated that for illustrative, "order-of-magnitude" purposes only, the total zonal requirement for SP 15 would be 19,190 MW and that for NP 26 would be 17,134 MW. Subsequently, in the workshops, the CAISO indicated a residual zonal capacity need in the amount of 6,290 MW for NP 26 and 7,566 MW for SP 26.

The CAISO presented its zonal study assumptions, calculations, and results at the Track 1 workshops. The workshop discussions yielded significant but not unanimous agreement that there is a need for the imposition of zonal procurement obligations on LSEs in addition to the existing system and local obligations. Of the parties filing post-workshop comments, Pilot Power believes that the zonal capacity need identified by the CAISO is "theoretical and potential." Pilot Power is concerned that there is no historical analysis showing that the potential issue actually arose in 2006 or in 2007 that caused the CAISO to engage in backstop procurement or take other steps to solve the problem.

Under the current RA counting rules, even if system, local, and import RA requirements are collectively satisfied by LSEs, the portfolio of RA resources procured by LSEs could result in a zone relying on transfer capacity across Path 26 that exceeds the path's rated capacity. Thus, for the same reason that we have adopted local procurement obligations to address reliability issues in local load pockets associated with transmission constraints, we find that establishing LSE-based procurement obligations to address the reliability problem caused by the Path 26 transmission constraint is reasonable and should be adopted. If this Commission does not address the problem through the imposition of LSE-based procurement obligations, the CAISO would likely need to rely on less cost-effective alternatives such as non-RA capacity or its backstop authority to balance needs within the zones. Such reliance on CAISO-based procurement is inconsistent with the LSE-based procurement objectives of the RA program and therefore ought to be minimized.

By definition, future loads and operational circumstances can only be forecast. Thus, it is true that the zonal procurement obligation addresses a "potential" as opposed to an "actual" zonal event. However, as with the RA program as a whole, we regard the establishment of LSE-based zonal capacity obligations as equivalent to the purchase of insurance for reliability. A prudent driver decides to obtain car insurance on the basis of informed judgment regarding risk assessment, not on the basis that he had an accident in the prior year. We believe that the same principle holds true here; we should not await the actual occurrence of a zonal reliability event before we take prudent action to avoid the occurrence of the next such event.

3.2. Zonal RA Implementation Proposals

Notwithstanding the zonal capacity need identified by the CAISO, pre-workshop comments and workshop discussions revealed substantial concern regarding the regulatory complexity of adding a third set of regulatory requirements to the existing system and local components of the RA program. Two alternative proposals for resolving the zonal capacity requirements emerged from the workshops. One, initiated by SCE, led to a joint proposal of the CAISO, the three IOUs, and TURN for a Path 26 Counting Constraint. The second proposal, advanced by DRA, was presented by DRA as a variation of the Path 26 constraint. On March 22, 2007, Joint Parties and DRA each submitted post-workshop refinements to the proposals that surfaced at the workshops. We summarize them below, then address our preferred approach to resolving zonal capacity needs identified by the CAISO.

3.2.1. Path 26 Counting Constraint (Joint Parties)

Recognizing that an explicit zonal RA requirement was being considered largely due to the concern that Path 26 may be collectively over-relied upon in the RA compliance showings of individual LSEs, the Joint Parties advocate the adoption of a Path 26 counting constraint for system RA starting with the 2008 compliance filing cycle. This approach would be in lieu of an explicit zonal RA procurement requirement. Essentially, Path 26 would be treated analogously to an RA import path for RA counting purposes. In brief, there would be a CAISO-determined, Commission-adopted limit on the amount of capacity LSEs may count crossing Path 26 in connection with their System RA compliance filings. The following five-step, CAISO-administered iterative process would be used to determine this counting constraint:

Step 1. The CAISO determines the amount of Path 26 transfer capacity available for RA counting purposes after accounting for Existing Transmission Contracts (ETCs) and loop flow.[3] The CAISO calculated the Path 26 transfer capability as 3,430 MW north-to-south and 2,583 MW south-to-north.

Step 2. The CAISO determines the baseline amount of Path 26 counting capacity that an LSE is eligible to receive in the allocation process without consideration of the impact of netting the north-south and south-north RA counting "flows" on Path 26. This baseline amount is the higher of (1) the LSE's load-ratio share of load in the zone or (2) the sum of the LSE's existing commitments—ETCs, Transmission Ownership Rights (TORs), and RA resource agreements in effect as of February 21, 2007 (Grandfathered RA Commitments). If an LSE has such Grandfathered RA Commitments that exceed its load-share ratio, other LSEs in that zone will receive a baseline allocation that is less than their load-ratio share. While we find the proposal unclear on this point, it appears that this reduced allocation for LSEs without Grandfathered RA Commitments reflects a pro rata share of the total amount by which the allocations for LSEs with Grandfathered RA Commitments exceed the load-ratio shares for those LSEs. The CAISO will notify LSEs of their baseline allocations by mid-July. An LSE will be able to receive more than its baseline share if additional capacity becomes available through the netting process identified in Step 3. Once the Grandfathered RA Commitments expire, an LSE's baseline share will revert to its load-ratio share.

Step 3. Once the baseline quantities are determined, LSEs will have an opportunity, but not an obligation, to submit RA resource contract commitments (Preliminary Path 26 Submittals) that exist as of July 31 of each year, including Grandfathered RA Commitments, that need to use Path 26 to deliver to the LSE's loads (Existing RA Commitments). The CAISO will use these Preliminary Path 26

[3] The transfer capacity on Path 26 must be de-rated to accommodate ETCs that are used to serve load outside the CAISO control area. "Loop flow" is common to large electric power systems and must be accommodated to prevent overloading of lines.

Submittals to "net" the north-to-south and south-to-north Path 26 RA counting impacts associated with the Existing RA Commitments. An LSE's Preliminary Path 26 Submittal cannot exceed its baseline Path 26 RA counting capacity. Once submitted, the Preliminary Path 26 Submittals will create a binding obligation on the LSE to include the Existing RA Commitments in its year-ahead and month-ahead RA compliance filings. The Existing RA Commitments submitted and accepted by the CAISO through the Preliminary Path 26 Submittals process will also be subject to all CAISO Tariff offer obligations. This Preliminary Path 26 Submittal process will take place each year.

Step 4. The CAISO will allocate the additional Path 26 RA counting capacity that was made available due to netting of existing commitments. This additional counting capacity will be allocated to LSEs based on load-ratio shares, and will be additive to the LSEs' baseline allocations. However, LSEs whose baseline Path 26 RA counting capacity exceeds their load-ratio shares because of Grandfathered RA commitments will only receive additional Path 26 RA counting capacity after all other LSEs have been "topped off" by being allocated additional Path 26 RA counting capacity in an amount that causes them to exceed their respective load-ratio share by the same percentage that the initial LSE receive because its baseline allocation exceeded its load-ratio share.

Step 5. The CAISO will notify LSEs of the final results of the Path 26 RA counting capacity process within 5-7 business days of July 31 of each year. This final notification can only increase the amount initially allocated to each LSE by mid-July in Step 2, but cannot decrease that initial allocation. In order for an LSE to count an RA resource that requires the use of Path 26 to be delivered to its load zone, an LSE would have to have sufficient Path 26 RA counting capacity.

3.2.2. Minimum Percentage Requirement (DRA)

DRA essentially agrees that the Path 26 Counting Constraint is a conceptually simple resolution of the reliability problem caused by potential over-reliance on Path 26. DRA nevertheless finds that that proposal's provisions for establishing the quantity of RA counting rights available on Path 26 are complicated due to existing RA resource commitments, loop flow, and netting impacts. DRA proposes that a simpler way to ensure an appropriate regional balance of RA resources is to set minimum percentages of System RA that must be provided by RA capacity located in either SP 26 or NP 26. The minimum percentages would be calculated by determining the load forecast for each zone, subtracting DR impacts, and adding 15% to determine a Total Zonal Need that includes a PRM. Then, to determine the Zonal Physical Capacity Need to be met through intra-zonal RA procurement obligations, the total of import and Path 26 capacity and DWR Liquidated Damages (LD) contract capacity would be subtracted from the Total Zonal Need. The minimum percentage to be applied to LSE procurement obligations would be based on the ratio of Zonal Physical Capacity Need to Total Zonal Need. Using data for 2008 that was available in the Track 1 workshops, DRA determined for illustrative purposes that each LSE[4] located in SP 26 would have to provide at least 53.0% of its System RA obligation from plants located within SP 26. For LSEs located in NP 26, the minimum percentage would be set at 63.5%. DRA notes that these percentages would have to be refined to take into account loop flow, the size of DWR LD contracts by zone, and the size of DR impacts within each zone.

DRA proposes that the CAISO would annually calculate the minimum percentages for each zone and provide the results to LSEs. LSEs would be required to show they have met the minimum intra-zonal percentage

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[4] Although DRA referred to "ESP" in presenting its proposal (DRA Zonal Capacity proposal, p. 4), we understand the intended references are to "LSE."

requirements in their RA compliance filings. DRA anticipates the percentages would change over time as changes occur in load, DR impacts, import capacity, and the size of DWR LD contracts.

3.2.3. Discussion – Adopted Approach for Zonal Reliability

In the wake of the Track 1 workshops, no party proposes that we establish a stand-alone Zonal Capacity RA requirement. Compared to such a requirement, the two alternatives before us represent relatively minor modifications to the existing System RA program that should operate to achieve the same objectives of a stand-alone requirement. We appreciate the parties' efforts in fashioning such practical solutions to reliability issues. We find that the relative RA program simplicity achieved by these alternatives is consistent with our stated objective to reduce regulatory uncertainty pertaining to the RA program. (D.06-07-031, pp. 23-24.)

Having determined that there is a significant zonal reliability problem arising from the physical constraint across Path 26, and that the problem should be addressed through LSE procurement obligations rather than CAISO procurement, we turn to resolving which of the two proposals—the Path 26 Counting Constraint or the Minimum Percentage Requirement—will more effectively resolve the problem both from a reliability and a cost standpoint.

DRA presented its proposal as a less complicated, and therefore preferable, alternative to the proposed Path 26 Counting Constraint. We are not persuaded that is the case, however. If the DRA approach is less complex, it is because it does not consider counter-flows across Path 26 that would allow netting of resources across the path. In contrast, the Joint Parties' Path 26

Counting proposal explicitly provides for such netting. By not providing for netting, DRA's approach unnecessarily restricts LSE access to economic resources at times when no physical limitation exists that would preclude such access. The effect of such a restriction would be a constraint on the RA market that could lead to LSEs and ultimately their customers paying more for RA capacity, with no resulting enhancement to reliability.

Moreover, the simplicity advantage of the DRA approach does not appear to be a straightforward proposition. As the Joint Parties point out, if we were to approve the Minimum Percentage Requirement it may be appropriate to implement it using monthly calculations of the physical zonal requirement. If such a determination were made, the need for monthly calculations would offset any simplicity advantage of the method. In addition, by assigning the same minimum percentage requirement to each LSE based on aggregate amounts of DR impacts, RA imports, Path 26 transfer capability, and DWR LD contracts, the DRA proposal in effect assigns a pro-rata allocation of these RA counting assets to LSEs. However, these are LSE-specific assets under the current RA regime. As the Joint Parties note, the proposal could result in a "false deficiency," i.e., an LSE could be found deficient with respect to its minimum required percentage of resources within a zone even though the CAISO's zonal reliability needs have been satisfied and the LSE has met its System and Local obligations.

AReM is concerned that the Path 26 Counting Constraint's grandfathering provision would give preferential access to Path 26 counting rights to some LSEs. AReM might be inclined to support the proposal if the Path 26 allocations were capped at the load-ratio share for each LSE. AReM has found that the RA intertie import allocation process to be contentious, and is concerned that it disadvantages ESPs. AReM is therefore hesitant to support a similar allocation process for Path 26 counting rights. Constellation et al., Pilot Power, and Sempra Global also raise concerns about the proposed allocation process for Path 26 and the preference it gives to long-term arrangements. Like AReM, Constellation et al. support making the allocation on a load-ratio share basis. Constellation et al. also disagree with the selection of February 21, 2007 as the cutoff for preferential treatment of RA contracts.

We find the grandfathering of existing arrangements under the Path 26 Counting Constraint to be reasonable. In particular, it is appropriate to recognize that some LSEs have entered into long-term commitments prior to the advent of a path allocation requirement, and that such procurement practices are consistent with the objectives of the RA program. We also note that according to Joint Parties, the impact of grandfathering is "inconsequential overall." It is proposed in response to the need to give effect to the policy of honoring DWR contracts for RA purposes. Joint Parties state there is only one ETC held by an LSE serving load within the CAISO control area that exists on Path 26, in the South to North direction amount of 52.5 MW.

Based on the foregoing, we will adopt the Path 26 Counting Constraint beginning with the 2008 compliance period, with one modification. Joint Parties propose February 21, 2007 as the cutoff date after which new RA resource agreements would not be grandfathered for Path 26 allocation purposes. We understand that this cutoff date was selected because it is the date of the Track 1 workshop at which the concept of the Path 26 constraint was first discussed. We do not find that date to be reasonable. As Constellation et al. point out, the workshop discussion was initially focused on the need for a zonal RA procurement requirement, not the mechanics of a path allocation. We will instead set March 22, 2007, the date the proposal was filed, as the cutoff date.

4. Local RA for 2008 and Beyond

4.1. 2008 LCR Study

In D.06-06-064, the Commission determined that a study of local capacity requirements conducted by the CAISO would form the basis for this Commission's Local RA program. As noted above, the CAISO published its 2008 LCR study on March 9, 2007. Following a March 21, 2007 stakeholder meeting, it filed an updated study on April 4, 2007. In Section 4.1 of this decision we address the extent to which the 2008 LCR study should be approved as the basis for local procurement obligations to be met by Commission-jurisdictional LSEs for the 2008 RA compliance year. We also address the need for improvements to the LCR study process.

4.1.1. Basing Local RAR on the 2008 LCR Study

The CAISO states that the assumptions, processes, and criteria used for the 2008 LCR study mirror those used in the Commission-approved 2007 study. The overall LCR trended upward from 2007 to 2008 due to load growth. The LCR for the Greater Bay Area was reduced from 4,771 MW to 4,688 MW (using LCRs associated with the Category C level of reliability) due to installation of the Vaca-Dixon 500/230 kilovolt (kV) transformer. The LCR for the Los Angeles (LA) Basin increased from 8,843 MW to 10,130 MW based largely on an evaluation of the South-of-Lugo operational path rating that was not available for the 2007 study. In addition, a new local area was identified—the Big Creek/Ventura area with an LCR of 3,658 MW. The total of LCRs for all areas increased by 22%, from 22,934 to 28,030 MW.

The magnitude of increases in LCRs, particularly in Southern California, led to substantial concern regarding the study and how its results should be translated into LSE procurement obligations. AReM recommends, among other things, that year-to-year increases in LCRs be capped at 10%. Drawing on the capping approach espoused by AReM, Aglet recommends a cap of 5%. SCE contends that the 2008 LCR study inappropriately used outages of intertie transmission lines to define local needs in both the Big Creek/Ventura Area and the LA Basin Area. SCE believes the increases in the amount of local generation required are therefore improper. SCE recommends that the LCR study be modified to recognize that San Diego area generation relieves South-of-Lugo loading. SCE further recommends that the LCR for the Big Creek/Ventura Area be defined by outages within the area, not on the contingencies identified by the CAISO. If the Commission approves the establishment of the Big Creek/Ventura Area, SCE believes that the Commission should either (1) not establish a local procurement requirement for that area based on the 2008 LCR study[5] or (2) if it does establish such a procurement obligation, explicitly waive penalties for LSEs that fail to meet their local requirement for the Big Creek/Ventura Area.

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[5] SCE characterizes this as a phase-in of the Big Creek/Ventura area. As we understand SCE's phase-in proposal, Commission-jurisdictional LSEs would be placed on notice by the issuance of the Track 1 decision that the Commission has approved the establishment of the Big Creek/Ventura Area for purposes of the RA program beginning in 2009.

The 2007 to 2008 LCR increase for the LA Basin Area appears large, but it is explained by a combination of load growth and an up-to-date evaluation of the effect of transmission upgrades on the South-of-Lugo operational path rating. The CAISO notes that if accurate data had been available for the 2007 study, the LA Basin Area LCR for 2007 would have been 9,923 MW, not 8,843 MW. Stated differently, the 2007 LCR study understated LA Basin Area requirements due to the lack of a current evaluation of the path rating. That does not render the 2008 study inaccurate or unreasonable, however. On the contrary, now that more current information regarding the path rating is available, it would be unreasonable to adhere to an understated LCR determination that was made a year ago in connection with the 2007 study.

SCE's objection to the establishment of the Big Creek/Ventura Area is based on the contention that the CAISO has changed the LCR study approach by using the contingency of an intertie outage. This objection does not appear to be well-founded, since the potential universe of transmission outages that may be considered for purposes of identifying the most severe contingency has consistently encompassed any transmission line, including interties. We find no substantial grounds for invalidating the LCR study, and therefore find that the Big Creek/Ventura Area should be established without a phase-in or blanket penalty waivers as proposed by SCE. No party has shown that the existing waiver procedure that was adopted by D.06-06-064 is inadequate to address LSEs' concerns about potential market power, if any, that may be associated with the Big Creek/Ventura Area. LSEs have been on notice since the March 2007 release of the 2008 LCR study that CAISO is proposing to establish the new area. As the CAISO notes, the implementation schedule for procurement obligations arising from the newly identified area is comparable to the schedule that was followed when local procurement obligations were first established last year pursuant to D.06-06-064. Similarly, we find inadequate justification for capping the year-to-year LCR increases as suggested by AReM and Aglet.

The LCR study is based on 1-in-10 year summer peak load forecasts. Aglet believes that the use of 1-in-10 forecasts leads to a high level of RA procurement that is not cost-effective. Aglet proposes that we approve local procurement obligations based on 1-in-5 forecasts. Using (1) "willingness to pay" data from a value-of-service study prepared for PG&E, (2) assumptions about RA resource costs drawn from the CAISO's Reliability Cost Services Tariff, and (3) an estimate that the 1-in-10 forecast leads to the procurement of an additional 364 MW by PG&E compared to a 1-in-5 standard, Aglet calculated benefit/cost ratios for various classes of PG&E customers. Aglet concluded that use of a 1-in-10 standard is not cost-effective for PG&E's residential customers unless resource costs are at or below $37/kW-year.

The PG&E specific value-of-service analysis before us relies on assumptions that may not be accurate or reliable for purposes of local RA.[6] For example, it assumes that a one MW reduction in LSE procurement will be realized for every MW reduction in LCR. That may not be a supportable assumption in light of the fact that local capacity procurement also counts

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[6] Aglet proposes that the SCE and SDG&E be directed to perform value of service studies similar in scope to the PG&E study. We find this proposal, which first appeared in Aglet's April 6, 2007 comments, to lack adequate substantiation. It may be appropriate to incorporate value of service analyses either in future LCR studies or in future Commission proceedings that consider the use of LCR studies if it can be shown that the benefit of this approach outweighs the cost to the IOUs of performing the requisite studies.

towards system RA obligations. In addition, Aglet's benefit/cost conclusions at best apply to PG&E's residential customers. For all other classes of PG&E ratepayers the calculations show high, positive benefit/cost ratios associated with the higher reliability standard.

Even if we did accept the assumptions and analysis behind Aglet's conclusions, we would then need to weigh the apparent residential customer interest in reduced reliability against the interest of other customers in a greater level of reliability. This is because current system design does not permit the CAISO and the utilities to operate the electric system to differentiated reliability levels depending on customer class. Aglet's analysis does not provide any basis for making such a determination. In summary, we find no reason for departing from the use of 1-in-10 peak load forecasts for determining local reliability capacity needs.

In the following section we describe actions that are intended to address ongoing concerns about transparency and timing of CAISO's LCR study process. Notwithstanding the need for process improvements, we are persuaded that the 2008 LCR study should be approved as the basis for establishing local procurement obligations for 2008 applicable to Commission-jurisdictional LSEs. D.06-06-064 adopted a framework for Local RA and established local procurement obligations for 2007 only. We clarify here that the Local RA program and associated regulatory requirements adopted in D.06-06-064 are continued in effect for 2008, subject to the modifications and the 2008 LCRs adopted by this decision.

In D.06-06-064, the Commission determined that a level of reliability associated with "Option 2," which was based on "Category C" criteria as defined in the 2007 LCR study, should be applied as the basis for local procurement obligations.[7] The Commission stated that "[w]hile we expect to apply Option 2 in future years in the absence of compelling information demonstrating that the risks of a lesser reliability level can reasonably be assumed, we nevertheless leave for further consideration in this proceeding the appropriate reliability level for Local RAR for 2008 and beyond." (D.06-06-064, p. 21.)

The CAISO explains that the LCRs determined for the various local areas that are based on Option 1/Category B reliability level implicitly rely on load interruption as the only means of meeting any Applicable Reliability Criteria beyond the loss of a single transmission element. The CAISO states that Option 2 is the local capacity level that it needs to reliably operate the grid per NERC, WECC, and CAISO standards. The CAISO therefore proposes that the Commission approve the Option 2/Category C reliability level and the associated LCRs. No party has submitted compelling information that would cause us to depart from the standard approved for 2007 and recommended by the CAISO for 2008. We therefore approve and adopt the Option 2/Category C reliability standard for setting local procurement obligations.

On May 10, 2007, the CDWR filed a motion for acceptance of late-filed comments to note concerns with the LCR study process and to advise the

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[7] Pub. Util. Code § 345 provides that the CAISO "shall ensure efficient use and reliable operation of the transmission grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western Electric Coordinating Council [(WECC)] and the North American Electric Reliability Council [(NERC)]. See D.06-06-064, pp. 16-17, for a discussion of reliability options identified in the LCR report and their relationship to planning standards established by the NERC.

Commission of "apparent factual errors" in the 2008 LCR study. In particular, the CDWR believes that the CAISO erroneously identified CDWR pump load located in the Big Creek/Ventura Area as part of the load to be subject to local procurement requirements. CDWR states that the load is controllable and should not be included as firm load. The ALJ granted the motion in an e-mail ruling dated May 14, 2007.

CDWR has raised an important question about the appropriate treatment of pump load in the LCR study process that warrants investigation for future LCR studies. It may be the case that pump load should not be treated the same as tariffed interruptible DR programs, which programs generally qualify as resources under the RA program.[8] It does not appear, however, that this issue was adequately and timely developed such that a modification to the 2008 LCR is justified at this time. On the other hand, it may be appropriate for the CAISO and parties to consider the CDWR's concerns in the supplemental LCR review process described below. To the extent that pump load is reflected in the Big LCR for a local area but is also controllable or interruptible and therefore available as a DR resource, it may be feasible for CDWR and other agencies to enter into appropriate arrangements with LSEs for their use of this load in fulfillment of procurement obligations for the area. This topic should be included among those taken up in the workshop on LCR study improvement described in the following section.

Some parties have suggested that we allow for the identification of 2008 LCR study refinements and corrections as well as operational solutions that

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[8] See Section 5 of this decision.

might result in reduced LCRs without jeopardizing reliability. In view of both the desirability of ensuring that LCRs are based on accurate and current data and the limited time available for, such LCR revisions, we will approve a supplemental LCR study review procedure based on that adopted in D.06-06-064 in connection with the 2007 LCR study. Accordingly, while we adopt the CAISO's 2008 LCR study for purposes of establishing local procurement obligations in the coming year, we will authorize Energy Division to calculate and establish reduced local procurement obligations, if any, that might result from further LCR study analysis, either as determined by or agreed to by the CAISO staff. This is a ministerial determination, and the Energy Division is not authorized to approve LCR study adjustments or revisions that increase any LSE procurement obligation or that use a reliability standard lower than that approved herein. Notice of the operational solutions and study corrections approved by the CAISO, if any, should be provided to parties and stakeholders to the extent permitted by confidentiality protocols.

Staff analysis has shown that the LCR study did not use CEC-approved load forecast data for the San Diego local area. We therefore request the CAISO to recalculate the San Diego Area LCR using the correct data. We realize this adjustment may result in an increased LCR for that area, and hereby approve such increase.

4.1.2. Improving the LCR Study Process

For the 2008 LCR study, the CAISO formed the LCR Study Advisory Group (LSAG), a representative cross-section of stakeholders technically qualified to assess the issues related to the study and to recommend changes where needed. Notwithstanding this generally positive development, several parties have expressed concerns about the 2008 LCR study process. CMUA notes, for example, that by the time the LSAG began work in earnest, it was considered too late to review changes to the methodology in time for the 2008 RA cycle.[9] CMUA, whose members were among active CMAG participants, believes there needs to be better coordination of the CAISO study cycle consistent with CAISO tariff requirements and the Commission's RA schedule. CDWR faults the study's lack of transparency in connection with the asserted failure to disclose study inputs and assumptions. PG&E observes that "time and resource constraints on the CAISO have been detrimental to the process of developing a clearly understood, verifiable study in which assumptions and judgment calls are sufficiently transparent to assure consistency with the Commission's principles and expectations." (PG&E Comments, p. 4.) PG&E goes on to state that for 2009 and beyond, a more deliberative process is needed that is consistent with Grid Planning studies, subject to checks and balances, and designed for greater stability. The CAISO itself acknowledges in its reply comments that study improvements must still be made.

It is clear that concerns about timing and transparency issues continue to vex the LCR study process. Stakeholders remain uncertain regarding study inputs and assumptions, and opportunities for meaningful dialogue seem limited. In view of the tight schedule of the RA compliance cycle, LSEs face

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9 Although CMUA's members are not subject to the Commission's RA program, CMUA is concerned that decisions made in this proceeding will impact all entities within the CAISO Control Area. This is because the LCR study results serve as the foundation for determining Local Area Capacity obligations and the CAISO's backstop procurement.

significant if not severe constraints on their ability to plan their procurement activities. This Commission's own decisionmaking process is also impacted by the schedule. There is simply too little time between the publication of the LCR study report in March and the issuance of a Commission decision in June to enable the careful and methodical review and refinement that the study warrants.

Improvements to the LCR study process for 2009 and beyond (including the schedule) are both needed and achievable. It would be helpful for the CAISO to issue the planned study assumptions for comment prior to conducting the study. More generally, PG&E's and TURN's proposals for improving the LCR process merit careful consideration.[10] We note that the CAISO shares the objective of integrating the LCR and grid planning processes, and we agree this objective should be pursued. In addition, stakeholders would clearly benefit from the CAISO's multi-year assessment of LCRs taking into account known and planned transmission system developments. As PG&E points out, a long-term forecast of LCRs may be essential for both transmission planning and generation procurement activities. Also, as AReM points out in its comments on the proposed decision, LSEs would benefit from early notice (e.g., two years) that the CAISO has identified a new load pocket.

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[10] PG&E Comments, pp. 6-7; TURN Reply Comments, p. 3. PG&E suggests that CAISO publish a study plan at the beginning of each year for stakeholder comment, that LCR stakeholders have adequate time to review and comment on draft LCR studies, that the CAISO meet with PTO stakeholders to review and verify draft results, that broader stakeholder meetings follow those PTO meetings and that the CAISO issue the final study after responding to questions and comments on the draft report. TURN proposes schedule reforms that would better allow stakeholders to review and comment on the study.

We ask our Energy Division to collaborate with the CAISO in developing proposals for LCR study process improvements and to convene a workshop to be held in the summer of 2007. The workshop should address, at a minimum, the need for timely submission of operating solutions, opportunities for stakeholders to review and discuss LCR study input assumptions and methodology prior to the actual conducting of the study, and opportunities for stakeholders to provide input on the draft LCR study well in advance of the final LCR study report. Following such workshop, we anticipate the issuance of an Assigned Commissioner's ruling directing the implementation of process improvements that have been identified through such collaboration and workshops.

4.2. Probabilistic Analysis in LCR Studies

In D.06-06-064 the Commission indicated support for using a probabilistic approach to the LCR study as it could lead to more economically efficient decisions regarding the capacity that LSEs must procure at any particular location. The Commission asked the CAISO and other parties to take all reasonable steps to implement this approach as soon as practicable. Recognizing that the CAISO will need to take a lead role in moving to a probabilistic approach for future LCR studies, the Phase 2 Scoping Memo asked the CAISO to present (1) a discussion of how probabilistic analysis can be incorporated into future LCR studies, (2) its recommendations on the steps to be taken by the CAISO, and (3) its recommendation as to the actions that the Commission should take on this topic.

The CAISO made its presentation for pursuing a probabilistic LCR study in the Track 1 workshops. The CAISO estimated that from the granting of initial funding for this study and gaining commitment from CAISO management, a proposed probabilistic study can be completed for consideration for implementation in the RA program within two years. The study would determine the Loss of Load Probability (LOLP) for each Local Area in RA, which could be used in setting future Local RAR. Milestones identified by the CAISO included adopting an LOLP methodology, evaluation and purchase of software, data needs identification and gathering, study assumptions and stakeholder input, data loading and modeling, first run results, a stakeholder review, and production of final results. Additionally, the CAISO recommended using the LSAG to address the technical issues involved with a LOLP study.

Parties generally support the Commission's and the CAISO's vision for incorporating probabilistic analysis into the LCR study process, although there are some questions regarding the priority of the undertaking. For its part, the CAISO has indicated its commitment to develop and integrate LOLP into the grid planning process for potential application in the RA program, consistent with strictures of competing priorities.

We remain supportive of a transition to probabilistic analysis for future LCR studies, and are gratified by general stakeholder support and the CAISO's commitment to move forward within the limits of its resources. As with the LCR study process generally, the process of incorporating LOLP analysis into the LCR study should be as open to stakeholder participation. There may be an appropriate role for the LSAG, but the opportunity for meaningful stakeholder participation should not be limited to subject matter experts. Because this is expected to be a two-year undertaking, and the start date has not yet been fixed, we intend to monitor progress toward achievement of the objective of probabilistic LCR analysis as the underpinning for Local RA. We therefore request that the CAISO submit periodic status/progress reports, not less frequently than bi-monthly, to our Energy Division and serve those reports on the service list for this proceeding or successor proceeding that addresses RA.

4.3. Seasonal LCR Analysis

Because 1-in-10 summer peak loads do not occur year round, parties have suggested that the CAISO calculate seasonal variations in the LCR. In theory, this would allow reduced local procurement obligations during times of the year when loads are lower. AReM contends that the current requirement to meet a peak requirement on a year-round basis is an onerous burden for LSEs, and particularly so for ESPs. AReM notes that some ESPs have local procurement requirements that nearly exceed their System RAR in some off-peak months. PG&E shares the view that the seasonal difference in LCRs could be very significant, and that for many areas there may be no winter requirements at all. System-wide, PG&E notes, peak loads during the winter are over 30% lower than summer peak loads. Also, most transmission line winter ratings are 25%-40% higher than summer ratings.

The CAISO, which opposes further consideration of a seasonal LCR at this time, identified several technical hurdles, operational impacts, and programmatic issues that would be associated with a seasonal LCR study. The technical hurdles involve LCR study assumptions and impacts such as planned outages, resource portfolio effectiveness, transmission capability into local areas, and deliverability of resources off peak. Operational impacts identified by the CAISO include potential effects on the CAISO's outage coordination process and a greater potential to rely on backstop procurement because resource assumptions on effectiveness in meeting contingencies may not be valid with a potentially lower LCR. This could lead to the RA resource mix not being adequate in lower load situations. Programmatic issues identified by the CAISO include the need for reevaluation of resource deliverability and import capability, and a greater administrative burden on LSEs.

We concur with the CAISO's assessment that we lack sufficient evidence to conclude that the potential benefits of a seasonal LCR approach outweigh the likely costs. Under the circumstances, and also in light of the fact that the current LCR study process is already time- and resource-intensive, we are hesitant to push forward with a seasonal LCR policy at this time. We are open to demonstrations of cost-effectiveness of seasonal LCR in future RA proceedings. We also believe that PG&E's recommendation for targeted pilot studies warrants careful consideration by the CAISO and stakeholders. While we are not prepared to order such pilot studies on the record before us, we welcome proposals for pilot studies, which may be taken up in the previously described summer 2007 workshop on improving the LCR study process.

4.4. Load Migration

Currently, LSEs must procure 100% of their Local RAR on a year-ahead basis. The Phase 2 Scoping Memo found that it would be reasonable to receive proposals for a monthly compliance filing process for Local RA to permit or require LSEs to reflect load migration impacts.

In response to the Phase 2 Scoping Memo's call for pre-workshop proposals on Track 1 issues, several parties commented on the pros and cons of monthly true-ups of local RAR to account for load migration without offering proposals for their implementation.[11] Sempra Global offered a proposal suggesting that protocols for Local RA be as similar as possible as System RA, including monthly true-ups. A key component of the Sempra Global proposal was that the Local RAR for each LSE should be expressed as the ratio of the total Local RAR in the utility service area to the total System RAR in that service area. Sempra Global suggested that using a percentage rather than a flat MW value would allow for variations in monthly peaks and more accurate true-ups.

The workshop discussions led to general consensus that a MW allocation would be better than a percentage allocation, but several questions remained about the need for numerical examples of how such an approach would actually work. Upon request and direction of the Energy Division, SES e-mailed a revised proposal for monthly true-ups on March 22, 2007. The latest proposal provides that when the adjusted monthly forecast exceeds the year-ahead, peak-month load forecasts, there would be an LSE obligation to procure additional Local RA capacity. When the monthly true-up forecast is below the year-ahead forecast for that month, the LSE would be permitted to adjust its Local RA obligation downward according to a "baseline ratio."

The comments reveal that significant problems remain in designing a monthly true-up mechanism, and that the latest proposal from SES is not ready

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[11] In proposals filed on January 26, 2007, AReM, Constellation et al., and CLECA/CMTA supported monthly true-ups. PG&E recommended exploration of seasonal or quarterly determinations that would include the opportunity for monthly trading. DRA proposed monthly compliance filings for the four summer months. SCE and SDG&E opposed monthly true-ups.

for adoption. As TURN notes, the proposal appears asymmetric with respect to when it would allow for increases and decreases in the LCRs for particular LSEs. Based on factual scenarios in examples in the proposal, an LSE that loses 500 MW of load in May of the compliance year would see its LCR reduced by 250 MW for every remaining month of the year, but the LSE that gains the same 500 MW of load in May would face an increased LCR that varies by month. This could lead to a shortfall in meeting the total LCR requirement. We note that Constellation et al. state that additional work on the proposal is needed, and Sempra Global acknowledges that the SES proposal would benefit from further discussion.

We remain open to consideration in future proceedings of a mechanism to true-up local procurement obligations to account for load migration, whether such mechanism is applied on a monthly, quarterly, or seasonal basis. We nevertheless conclude that there is no viable proposal for such a mechanism that can be adopted by the Commission at this time. In particular, we do not find that the SES proposal can be provisionally approved by this decision while remaining questions are left to a post-decision workshop. Further consideration by the Commission of a complete proposal on which there has been opportunity for comment would be required.

4.5. Local Area Aggregation

D.06-06-064 established aggregation of certain local areas for the 2007 Local RAR. This approach had two components. First, the Commission determined that each LSE's allocation of Local RAR for each local area would be based on its share of load in the IOU distribution service area. It then determined that six local areas within the PG&E territory (Humboldt, North

Coast/North Bay, Sierra, Stockton, Greater Fresno, and Kern) should be aggregated as one for purposes of Local RAR for compliance year 2007. It did so to address concerns about supplier market power in those six areas.

During the February 21 Track 1 workshop, stakeholders reached consensus in favor of an Energy Division proposal that (1) continues to calculate Local RAR based on load share of IOU distribution service area, and (2) continues the aggregation of the six PG&E local areas for compliance year 2008. Workshop participants expressed the concern that there will be a need to reevaluate the aggregation in future years. The workshop did not address allocation issues related to the Big Creek/Ventura Area proposed in the CAISO's 2008 LCR study.

The comments confirm consensus on these Energy Division recommendations, and we adopt them as reasonable extensions of the current program. As we stated in D.06-06-064, we would prefer not to provide for aggregation because it might lead to over- or under-procurement in some areas. Moreover, the need for aggregation may be an indication that there has not been sufficient investment in transmission and/or generation. We note however, that the CAISO determined on the basis of last year's experience that aggregation of the six PG&E areas is again acceptable, subject to continued monitoring. We accept the consensus of the participants that this aggregation is reasonable for 2008. We expect to again consider this question when we address local RA for 2009, and we agree with Constellation et al. that it would be helpful for the CAISO to report on an annual basis whether local area aggregation has led to CAISO backstop procurement.

The comments also reveal near-consensus that aggregation of the two local areas in the SCE territory should not be approved. AReM, however, asks that these two areas be aggregated. Countering AReM's request, SCE notes that generation located in each of the two areas will not mitigate overloads on transmission elements that are driving the other area's local capacity needs. Aggregating the areas could result in inefficient generation mix and additional CAISO backstop procurement, SCE contends. The CAISO concurs that such backstop procurement might be necessary, noting that if aggregation of these areas were permitted, LSEs could satisfy virtually all the combined obligation through capacity located solely in the LA Basin Area. As TURN notes, aggregation of the PG&E areas is appropriate because a number of those areas are small and/or contain resources primarily under IOU control. In the SCE territory, the Big Creek/Ventura Area has a relatively large LCR of 3,658 MW and the available resources (which exceed the LCR by a significant amount) are not predominantly under IOU control.

Although AReM raises general concerns about market power that lead to its proposal for aggregation of the SCE territory load pockets, it does not show that existing market power mitigation provisions are inadequate to address these concerns. Nor does AReM address the concerns about reliability and backstop procurement raised by the CAISO, SCE, and TURN. We find insufficient justification for aggregation of the LA Basin and Big Creek/Ventura Areas, and therefore determine that such aggregation will not be approved.

4.6. Waivers of Procurement Obligations

4.6.1. Local Area Resource Deficiencies

With respect to certain local areas, the LCR study identifies deficiencies in qualifying capacity resources. In the 2007 study the CAISO determined there were such deficiencies in the Sierra, Stockton, Greater Fresno, and Kern local areas that totaled to 466 MW. In the 2008 study the CAISO again identified such resource deficiencies in the same areas that total to 693 MW.

Because it would not be "reasonable to require LSEs to procure capacity that, according to the LCR study, does not currently exist in an area," the Commission directed the Energy Division to calculate reduced LCRs for those areas. (D.06-06-064, pp. 21-22.) The Commission stated that it was authorizing this "blanket waiver" treatment of deficiencies for 2007 only.

In its pre-workshop proposal, the CAISO noted that several transmission projects have been identified that will reduce the LCRs in currently deficient local areas for 2008 and 2009. The CAISO stated that for the projects scheduled to be in service in 2008, the precise amount of LCR reduction is being assessed in the 2008 LCR study. The CAISO states that to the extent the deficiencies are not eliminated, a continuation of the existing waiver policy appears appropriate for the same reasons expressed in D.06-06-064.

We will again approve blanket waiver of the local procurement requirement in the resource-deficient areas identified by the CAISO. LSEs should only be responsible for procurement to the level of resources that exist in the area.

4.6.2. Trigger Price for Waivers

In addition to the blanket waiver discussed above, D.06-06-064 approved a waiver process whereby an LSE would be able to specifically request waiver of a local procurement obligation if certain conditions are met. An important component of the adopted process is a capacity price of $40 per kW-year which functions as a threshold that could lead to a waiver grant. Energy Division proposed continuing this process, and there was general consensus favoring this proposal. IEP, however, contends that the waiver trigger of $40 per kW-year is unreasonably low, and proposes that it be doubled to $80 per kW-year. IEP asserts that is a conservative estimate of the cost of new entry.

We find insufficient record basis for modifying the waiver process or the trigger price adopted in D.06-06-064. As SCE notes, the Phase 2 Scoping Memo did not provide clear notice that proposed modifications to the waiver trigger price would be considered in Track 1. While IEP contended in its January 26, 2007 Track 1 proposal that the current waiver trigger is artificially low, and at that time it suggested that the Commission should consider the market price of capacity, this issue was not adequately addressed in the workshops. IEP's proposal to double the waiver trigger based on the cost of new entry first appeared in its post-workshop comments. As AReM points out, the trigger price was not adopted with the intention of its being a price signal for new capacity investment; it was established to provide an objective criterion for initiation of a regulatory process. Finally, as PG&E observes, the waiver trigger should not be raised without careful consideration of potential market power concerns, yet such consideration is not enabled by the current record.

5. DR Issues

5.1. Allocating DR to Local Areas

The RA program currently allows dispatchable DR resources to be "taken off the top" of an LSE's System RA procurement obligation. D.06-06-064 determined that dispatchable DR credit should also be allocated to each local area and counted for Local RAR to the extent feasible, but it recognized that it may not be possible for the 2007 compliance year due to the technical problems of mapping DR credits to local areas. It was possible to assign a DR allocation for the SDG&E service area since that area corresponds to a defined local area. It was not possible to do so for 2007 in the PG&E and SCE areas. In the Track 1 workshops PG&E and SCE presented and explained their proposals for allocating DR to local areas beginning with the 2008 compliance year.

SCE evaluated two allocation methods—estimation of customer impact by zip code and by substation. The former approach presents accuracy limitations and the latter requires a data intensive effort. SCE determined that under the zip code method, approximately 70 percent of its total DR resources would apply to the Local Area. PG&E believes that it will be able to determine the amount of DR that is located within each load pocket. Both IOUs are confident that the DR allocations can be completed in time for data to be evaluated as part of the DR allocation process for the 2008 RA compliance year.

We reiterate our policy preference that dispatchable DR programs should be counted as Local RA resources to the extent feasible. We recognize the technical issues involved in mapping these resources to local load pockets, and we are encouraged that both PG&E and SCE have identified mechanisms that can be implemented for the 2008 compliance year. While mapping according to zip codes may be less precise than alternative approaches, we find that this approach yields acceptable precision in allocations. We direct the IOUs to continue working with the CEC, the CAISO, and the Energy Division so that the policy implementation can be carried out to completion for 2008.

5.2. Emergency and Interruptible DR Programs

DR programs reduce load and therefore reduce the need for generation resources. There are two basic types of DR programs—reliability programs that are activated during periods of system stress and price responsive programs where energy users are paid to reduce consumption when energy prices are high. Both types DR programs are recognized as RA resources, subject to conditions and counting protocols determined in D.05-10-042.

The CAISO contends that interruptible and other DR programs that are not sufficiently coordinated with its market processes should not count for RA purposes. The CAISO takes the position that only those DR programs that can be committed a day-ahead should be allowed to count. The CAISO requests that the Commission reverse its prior decision to allow emergency and interruptible DR resources to count for RA compliance purposes.

Several parties responded in opposition to this request of the CAISO. They note that the emergency and interruptible programs have proven reliable and have considerable operational value that allows the CAISO to avoid shedding load. CLECA and CMTA are concerned that if the programs do not count for RA purposes, the IOUs will have less interest in pursuing them despite their operational value. Some parties indicate concerns about paying for the costs of DR programs if they do not count for RA.

We recognize the underlying concern of the CAISO regarding these DR programs. Despite their widely recognized value for operational purposes, the interruptible and emergency programs do not mesh well with the CAISO's day-ahead market processes. On a day-ahead basis, the CAISO must plan to dispatch resources to avoid emergencies and load shedding. A resource that is available only in an emergency, or that by its nature constitutes load shedding, cannot be dispatched a day ahead as are generation resources. On the other hand, as CLECA and CMTA point out, the CAISO knows on a day-ahead basis that these programs will provide it with reliable, dispatchable reserves to meet its needs the following day.

It appears that at least one preferred solution to this mismatch of resources and CAISO market rules would be to craft DR programs that are both attractive to customers and closely coordinated with the CAISO's day-ahead market processes. Subject to an appropriate transition mechanism that gives recognition to current arrangements entered into in good faith reliance on IOU tariff provisions, it may be appropriate to work toward the eventual exclusion of emergency based DR programs from the RA program. Such a determination cannot reasonably be made at this time, however.

R.07-01-041 was established to address various DR program issues, including consideration of modifications to DR programs needed to support the CAISO'S efforts to incorporate DR into market design protocols. Pending the outcome of R.07-01-041 regarding this issue, we find it is at best premature to order a reversal of our earlier decision to allow emergency and interruptible DR programs to count for RA purposes.[12]

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[12] We find additional support for this approach in *Order Granting In Part And Denying In Part Requests For Clarification And Rehearing*, issued April 20, 2007 in FERC docket No. ER06-615 at p. 222, ¶ 560, which reads in part, "[w]e believe that the CAISO must be allowed to make technical determinations as to whether a particular resource (whether a generator or demand response) can support grid reliability. However, we agree that the CAISO should respect

Footnote continued on next page

6. Load Forecasting and Compliance Year

6.1. Quarterly Forecasting Protocols

The RA program relies on the load forecasts supplied to and checked by the CEC as the foundation for each LSE's RAR. In order to establish the System RAR, CEC reviews the load forecast submitted by each LSE, reconciles the aggregate of those load forecast against its own forecast for each IOU service territory, and generates an individual load forecast for each LSE for each month of the year. LSEs currently submit a year-ahead load forecast for System RAR and then submit monthly load forecasts two months in advance of the applicable month to allow for load migration.

The Energy Division staff raised an issue in the Track 1 workshops based on concerns with the accuracy of load forecasting and load migration it has observed in its RA compliance reviews. The timing of the two-month-ahead load forecast can make it difficult to account for new customers or actual retention rates of existing customers when significant changes occur. Staff also noted that LSEs frequently have load migration that is stable from month-to-month and that ESPs generally forecast their load by accounting for known and expected load retention, but not new accounts.

Energy Division and CEC staff proposed a quarterly load forecast protocol that would replace the monthly load forecast approach. The objectives are to increase the accuracy of load forecasting, support the development of

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California's determination that energy efficiency and demand-side resources receive the highest priority in meeting future reliability needs. We therefore direct the CAISO to coordinate with the [California Public Utilities Commission] to minimize the potential for disagreements as to whether particular demand-side resources qualify on a technical basis in meeting resource adequacy requirements."

quantitative forecast accuracy standards, reduce the amount of load that is unaccounted for in the current RA program, provide flexibility for LSEs in making monthly load forecasting adjustments, and eliminate unnecessary filings.

The workshop participants expressed concerns about the after-the-fact review of load forecasts to actual loads, Commission enforcement of accuracy provisions, and penalty mechanisms for excessive error that were not clearly defined. No consensus was reached regarding the quarterly forecast approach.

The comments and replies reveal a substantial lack of support for adopting this proposal for the 2008 compliance year, and it is apparent that a number of questions regarding its efficacy remain unresolved. We urge the staff and the stakeholders to continue to evaluate alternatives for achieving the important objectives identified by the staff.

6.2. Redefining the Compliance Year

The Energy Division staff suggested an approach for better coordinating the RA compliance year with the annual load forecasting process by the CEC. Specifically, the RA program year would be May through April instead of January through December. Staff noted that system operators elsewhere follow this approach. Staff believes that significant benefits would include enabling LSEs to adjust their procurement to meet their RA requirements and incorporating the CEC's updated, post-summer load forecast that becomes available in the fall of every year.

While the workshop participants were generally open to this proposal, it was not sufficiently refined to warrant approval for 2008. Several parties expressed the need to review a complete proposal in order to evaluate the feasibility of a changed RA compliance year. Staff intends to develop a draft proposal for 2009 that would be more aligned with the CEC's load forecasting process and to provide the proposal to public stakeholders for review and further discussion. We encourage the staff to pursue this approach, while also considering and balancing the stated need for regulatory stability in the RA program.

7. Backstop Mechanism

The Commission has recognized that close coordination of the Local RA program with backstop procurement by the CAISO is necessary to promote cost-effective procurement. Over-reliance on backstop procurement is fundamentally at odds with the LSE-based procurement objective of the RA program. On the other hand, it is widely recognized that the CAISO requires access to some form of backstop procurement opportunities to insure against any capacity shortfall from the RA program.

In this respect, one of the long-term policy objectives of the Commission is to minimize the use of the CAISO's RMR process. In D.06-06-064, the Commission acknowledged that the RMR process would remain in place as a backstop reliability mechanism for 2007. Notwithstanding the long-term objective to minimize RMR reliance, the Commission determined that RMR units should generally qualify as Local RA resources. Another backstop mechanism that the CAISO uses at this time is the Reliability Capacity Services Tariff (RCST). The RCST is scheduled to expire at the end of 2007, although it is generally anticipated that the RCST or a similar replacement would be extended on an interim basis pending implementation of the CAISO's Market Redesign and Technology Upgrade (MRTU). MRTU implementation is currently targeted for 2008.

To address uncertainty regarding the RMR process for 2008 as well as uncertainty about when an RCST extension or a replacement mechanism will be approved by FERC, coordination of the RA program for 2008 and possibly beyond with any backstop mechanism was the subject of extensive workshop discussions. The CAISO discussed a proposal for continuing minimal usage of RMR in 2008 and using RCST as an interim backstop mechanism until MRTU can be implemented. The CAISO also committed to convene a public stakeholder process in April 2007 for development of a new backstop mechanism that would meet the needs of the CAISO's MRTU.

The challenges to coordinating this Commission's Local RA program and the CAISO's backstop procurement activities are significant. They include potential timing issues that, if not carefully addressed, could lead to costly and unnecessary over-procurement. It is also important to ensure that LSEs remain obligated to meet their procurement obligations, and that "free riding" and associated cost shifting are avoided. For the 2007 process, D.06-06-064 established a detailed process for coordination of RA and RMR activities. According to this plan, LSEs submitted preliminary Local RA filings in September and the CAISO then designated RMR units on October 1st. LSEs then procured additional units needed to meet their Local RAR showing in November.

The workshop discussions yielded eight separate proposals for coordinating Local RA and CAISO backstop procurement for 2008. In the wake of post-workshop comments and replies, widespread support has centered on "Proposal 8," which is summarized below:

> Proposal 8: Integrate RMR/Local RAR and use the 2007 schedule. On October 1st, the CAISO would only designate units with 2007 RMR contracts that were not under RA contracts as shown in the preliminary RA filings. The CAISO would then address any [Local RA] deficiencies after the final Local RAR filing by using new RMR contracts, RCST, or its successor.

Even those parties who favor one of the other alternatives generally concur that Proposal 8 is a second best alternative. We approve the Proposal 8 approach for 2008. As the CAISO points out, it addresses the concern that, due to the alignment of LARS and LCR study criteria, preliminary capacity showings by LSEs might effectively become final showings with the result that LSEs have no opportunity for supplemental procurement to minimize RMR designations. Also, while it continues the use of RMR unit designations, the Proposal 8 approach also works to minimize those designations. In view of the fact that uncertainty persists regarding the fate of RCST (or its successor) and MRTU implementation, there appears to be little choice but to recognize a minimal role for RMR unit designations in 2008. Proposal 8 does this while it is also consistent with promotion of LSE procurement as the primary procurement vehicle.

8. AB 1969

AB 1969 (Stats 2006, Ch. 731) requires electrical corporations to file tariffs providing for the purchase of renewable power from public water and wastewater treatment agencies. AB 1969 added Section 399.20 to the Pub. Util. Code to define and establish this requirement. Section 399.20 (g) provides that the physical generating capacity of an electric generation facility, as defined, shall count towards the electrical corporation's RA requirement for purposes of Pub. Util. Code § 380. The Phase 2 Scoping Memo provided that parties may address this topic while it also noted that prior RA decisions established a methodology to calculate the qualifying capacity (QC) for new generation, and it might not be necessary to take action in this proceeding.

The Energy Division proposed that the resources described by AB 1969 count for RA purposes and that the existing RA counting conventions are sufficient to accurately count QC for these resources. The workshop discussions and the post-workshop comments confirm this Energy Division proposal. We find that the current RA resource counting conventions are fully consistent with AB 1969's requirements. No further action is required in this proceeding to implement Section 399.20(g).

9. Minor Implementation Issues

9.1. Rounding Convention

D.06-06-064 adopted the following provision for rounding RA requirements:

> "LSEs should be exempted from procurement obligations of less than 1 MW in a particular local area. In addition, RARs of 0.5 and greater should be rounded up to the next highest MW and RARs of 0.49 or lower should be rounded down to the prior MW; provided, however, that this rounding convention does not supersede the local area exemption of less than 1 MW." (D.06-06-064, Conclusion of Law 13, p. 84.)

The Energy Division implemented the rounding convention for Local RAR but not for System RAR. Finding a need to clarify the rounding convention, the Energy Division proposed such a clarification for workshop discussion. Based on preliminary workshop discussions, Energy Division proposed the following rounding convention, which received consensus approval in a subsequent workshop:

- Local RAR rounding unchanged.
- For System RAR round at the level of RAR, after DR has been deducted and 15 percent PRM has been added.
- 1 MW minimum RAR, no LSE gets rounded down to 0 RAR.
- Grandfather existing LSEs with less than 1 MW RAR. They will not be rounded up.

We approve this uncontested proposal for clarification of the RA rounding convention. To the extent, if any, that this clarified rounding convention differs from or conflicts with D.06-06-064, it shall supersede that decision's provisions for rounding.

9.2. Wind Units With Less Than 3 Years Data

The monthly QC values used in RA for wind units are based on monthly historic performance during Standard Offer 1 (SO1) Peak hours from Noon to 6:00pm using a three year rolling average. This method was developed by participants in previous RA workshops and adopted in D.04-10-035 and D.05-10-042. The adopted methodology does not address wind units with less than three years of performance data. To address such units, the Energy Division developed a proposal for discussion in the workshops. The workshop participants reached consensus supporting the proposal, which is set forth below.

> **For new units:**
>
> The average wind production factor of all units within the Transmission Access Charge (TAC) area where the unit is located will be used. For example, for a new unit in if the average wind unit production as a percent of net dependable capacity (NDC) in the TAC area during June of year 1 was 23%, yr 2 was 22%, and yr 3 was 24%, the new unit's QC for June would be based on 23% of its NDC (23 + 22 + 24 / 3 = 23%).
>
> **For units with some operating experience, but less than 2 years of data:**
>
> The average wind production factor of all units within the TAC area where the unit is located will be used in place of the missing data in the 3 year formula. For example, if the average wind unit production in the TAC area as a percent of NDC during June of yr 1 was 23%, yr 2 was 22%, and yr 3 was 24%, and the new unit production for June was 21% of NDC for yr 3, the unit's QC for June would be 22% of its NDC (23 + 22 + 21 / 3 = 22%).
>
> **For units with at least 2 years of operating experience, but less than 3 years of data:**

> The unit's actual operating experience will be used. In some months the QC value will be based on 2 years of data rather than 3 years of data as established in the counting convention.

The post-workshop comments confirm this is a consensus proposal that should be approved by the Commission. As PG&E notes, establishing a counting convention for new resources should facilitate developers' efforts in qualifying the new RA capacity with the CAISO and create certainty regarding the QC amounts that buyers and sellers may expect from the projects. Energy Division, in consultation with the CEC and the CAISO as appropriate, should compute average wind values annually and publish the results for each TAC area by June 30 of each year.

PG&E believes that this proposal for wind resources may be appropriate for other as-available renewable resources such as solar, biomass, and small hydro. PG&E suggests that a portion of Track 2 be reserved for consideration and development of such proposals. We recognize that resource counting conventions developed in the past several years will need to be updated from time-to-time, and we therefore believe that PG&E's suggestion has merit. At the same time, we are mindful of resource constraints faced by parties as well as the Commission, and that Track 2 already has a heavy agenda. Rather than order this to be undertaken, we commend to the discretion of the Assigned Commissioner and the ALJ, in consultation with the Energy Division, the determination of whether it would be appropriate to expand Track 2 to consider this topic.

10. Standard Contract and Generator Obligations

D.06-07-031 was issued to provide guidance on the required elements of a standardized tradable capacity product that would facilitate transactions in furtherance of LSE procurement obligations. Several parties have expressed the need to develop a more standardized RA contract and more specific generator obligations in the RA program, and the issue was raised by Calpine in the workshops. While noting that this is not a Track 1 issue, the Energy Division requested Calpine to further explore developing a proposal with interested parties on this issue and to submit a proposal to be used for future Commission consideration.

Calpine et al. submitted such a proposal on March 22, 2007. It was developed through informal stakeholder discussions convened after the February 2007 workshops. The intent of the proposal is to implement the Commission's policy, expressed in D.06-07-031, of encouraging in the near term a standardized capacity product that is readily tradable, ensures availability of resources to the CAISO at times and places needed for reliability, and comports with RA Program requirements.

Calpine et al. state that the key to creating a readily tradable RA capacity product is making suppliers responsible directly to the CAISO, through explicit requirements in the CAISO tariffs. In addition, they seek to develop a standardized RA capacity contract with a standardized confirmation letter. To accomplish these steps, they ask that the Commission immediately initiate workshops to develop, for subsequent Commission approval, a pro forma standardized RA capacity contract. They also ask the Commission to co-host with the CAISO workshops to develop proposed tariff amendments that would define supplier obligations for submittal to the FERC.

The post-workshop comments strongly indicate that additional action is required if the objectives of D.06-07-031 are to be met. The comments also indicate that most if not all parties are ready to expand the RA procedural agenda at a time when several procedural tracks of the RA proceeding are already occupying the attention of the Commission and the parties. Because a readily available capacity product has significant potential benefits for the success of the RA program, we are willing to consider an expansion of the RA procedural agenda as necessary to consider this proposal. At the same time, we must consider the time and resource constraints that the Commission faces. We also are concerned that proponents may have underestimated the scope and depth of issues, and the ease with which they can be resolved.

Based on such concerns, the proposed decision would have directed the Assigned Commissioner and the ALJ, in consultation with the Energy Division and the CAISO, to determine the extent to which to expand Track 2 of Phase 2 of this proceeding to consider this topic. Commenting on the proposed decision, Calpine, et al., also joined by APS Energy Services, IEP, SDG&E, SCE, and TURN, believe that it is not necessary to expand Track 2 to consider their March 22 proposal. The parties believe that the additional work that is necessary to refine their proposal can be achieved in industry-sponsored workshops. They propose that we set a deadline of Fall 2007 for the parties to jointly report to the Commission on the results of their efforts and their procedural recommendations. We accept and endorse this procedural proposal. The parties should jointly report to the Commission on or before November 16, 2007 and provide the results of the industry-led process as well as their procedural recommendations (including a proposed schedule) for any Commission process that may be necessary to implement the proposal. To the extent their resource and time constraints permit, we encourage the Energy Division and the CAISO to participate in the industry process.

11. Future RA Proceedings

With this decision we complete the first track of Phase 2 of this proceeding. Major questions about the future of the RA program will be addressed in Track 2 of Phase 2, and Track 3 will address full implementation of Public Utilities Code Section 380 by considering RA obligations for small and multi-jurisdictional LSEs. Track 2 and Track 3 are currently targeted for completion early in 2008. When those tracks are completed it will be appropriate to close this proceeding.

While the nature of the future RA program and the associated procedural requirements cannot be fixed at this time, it is clear that there is an ongoing need for a procedural vehicle to address both modifications and improvements to the RA program as well as routine administrative (but not ministerial) matters that are not delegable to staff. Among other things, the Local RA program component requires annual approval of LCRs based on by the CAISO's LCR studies. For the near and intermediate term, we see a need for annual proceedings for these purposes.

We generally concur with PG&E's recommendation that an annual RA program assessment focused on summer program performance, coordinated by the Energy Division in consultation with the CEC and the CAISO, will be of significant value in the early years of the RA program. As we do not intend to establish reporting requirements that outlive their usefulness, we will revisit this determination upon recommendation of the Energy Division at an appropriate time.

12. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and Rule 14.2(a) of the

Commission's Rules of Practice and Procedure. Comments were filed by 16 parties or party coalitions. Replies were filed by 10 parties or party coalitions.

AReM proposes that we direct the Energy Division to publish, within one week of today's decision, proposed filing templates and related guidance for the 2008 RA compliance period that reflect the new requirements of the Path 26 Counting Constraint. AReM also proposes that staff be directed to hold an implementation workshop and to issue final compliance documents for 2008 by July 17, 2007. AReM further urges that we prescribe a schedule for the supplemental LCR review described earlier in this decision.

We recognize the importance to market participants of full and timely information regarding RA compliance requirements and filing procedures, and it appears that AReM has presented useful, concrete suggestions for our staff to consider as it moves forward to implement the RA program for 2008. We are not persuaded, however, that we should prescribe particular implementation actions that our Energy Division must follow. In D.06-07-031 we determined that the Energy Division should be authorized to modify the filing templates and instructions and promulgate additional filing procedures and instructions as necessary for the orderly implementation of the RA program and the changing needs of the program. (D.06-07-031, Conclusion of Law 8, p. 44.) We affirm that determination here.

In response to various concerns about scheduling matters that were raised by several commenting parties, and in consultation with the CAISO staff, the Energy Division has prepared a schedule of RA-related events for the coming year that includes the supplemental LCR review process, the CAISO's import allocation process, the coordinated backstop process for 2008, compliance filing dates, and the LCR study process for 2009. We approve and endorse this schedule, which is attached to this decision as Appendix A.

We note that the assigned Commissioner and the ALJ are authorized to implement changes to the schedule as may be necessary and appropriate. We also note that events and dates for the 2009 LCR process are subject to change pursuant to discussions at the summer 2007 workshop on the LCR study process. The Energy Division is authorized to implement changes to the schedule as may be necessary and appropriate with respect to events for which it is responsible, including workshop dates and minor changes to compliance filing dates that may be necessary for the orderly implementation of the RA program.

13. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Mark S. Wetzell is the assigned ALJ in this proceeding.

Findings of Fact

1. Existing transmission constraints preclude the CAISO's reliance solely on imported energy to serve load and comply with desired reliability performance standards in NP 26 and SP 26.

2. Under the current RA counting rules, even if system, local, and import RA requirements are collectively satisfied by LSEs, the portfolio of RA resources procured by LSEs could result in a zone relying on transfer capacity across Path 26 that exceeds the path's rated capacity.

3. Adding a third set of regulatory requirements to the existing system and local components of the RA program would add regulatory complexity to the program.

4. The proposed Path 26 Counting Constraint, which would limit the amount of capacity LSEs may count crossing Path 26 in connection with their System RA

compliance filings, treats Path 26 analogously to an RA import path for RA counting purposes.

5. The proposed Path 26 Counting Constraint as well as the proposed Minimum Percentage Requirement both represent relatively minor modifications to the existing System RA program that should operate to achieve the same objectives of a stand-alone Zonal RA capacity requirement.

6. The Path 26 Counting Constraint provides for netting of resources across that path, which would allow LSEs to access economic resources at times when no physical limitation exists that would preclude such access.

7. The proposed Minimum Percentage Requirement may not be significantly less complex to administer and comply with than the proposed Path 26 Counting Constraint, and it does not consider counter-flows across Path 26 that would allow netting of resources across the path.

8. Long-term resource commitments are consistent with the objectives of the RA program.

9. The 2007 to 2008 LCR increase for the LA Basin Area is explained by a combination of load growth and an up-to-date evaluation of the effect of transmission upgrades on the South-of-Lugo operational path rating.

10. Establishing the Big Creek/Ventura Area based on the contingency of an intertie outage is consistent with methodology used in prior LCR studies.

11. The Option 1 reliability level implicitly relies on load interruption as the only means of meeting any Applicable Reliability Criteria beyond the loss of a single transmission element, whereas Option 2 is the local capacity level that the CAISO needs to reliably operate the grid per NERC, WECC, and CAISO standards.

12. It may be possible for the CAISO to identify, in a supplemental LCR study review, 2008 LCR study refinements and corrections as well as operational solutions that might result in reduced LCRs without jeopardizing reliability.

13. Improvements to the LCR study process for 2009 and beyond are both needed and achievable.

14. A probabilistic LCR study can be completed for consideration for implementation in the RA program within two years from the date it commences.

15. There are technical hurdles, operational impacts, and programmatic issues that would be associated with a seasonal LCR study, and it cannot be determined at this time that the potential benefits of a seasonal LCR approach outweigh these issues.

16. The latest proposal for a monthly true-up mechanism for Local RAR could result in a shortfall in LSEs meeting the total LCR requirement.

17. The CAISO determined on the basis of last year's experience that aggregation of the six PG&E local areas is acceptable for 2008, subject to continued monitoring.

18. Generation located in each of the two local areas in the SCE service territory will not mitigate overloads on transmission elements that are driving the other area's local capacity needs, and aggregating those areas could result in inefficient generation mix and additional CAISO backstop procurement.

19. SCE and PG&E determined that DR allocations can be completed in time for data to be evaluated as part of the DR allocation process for the 2008 RA compliance year.

20. Emergency and interruptible DR programs have proven reliable and have considerable operational value that allows the CAISO to avoid shedding load.

21. If emergency and interruptible DR programs do not count for RA purposes, IOUs and customers may have less interest in pursuing them.

22. Current emergency and interruptible DR programs do not mesh well with the CAISO's day-ahead market processes.

23. The timing of two-month-ahead load forecasts can make it difficult to account for new customers or actual retention rates of existing customers when significant changes occur, yet LSEs frequently have load migration that is stable from month-to-month.

24. ESPs generally forecast their load by accounting for known and expected load retention, but not new accounts.

25. Changing the RA program year to May through April could potentially provide for better coordination of the RA compliance cycle with the annual load forecasting process by the CEC.

26. Costly and unnecessary over-procurement could occur if this Commission's Local RA program and the CAISO's backstop procurement activities are not coordinated.

27. The Proposal 8 approach addresses the concern that preliminary capacity showings by LSEs might effectively become final showings with the result that LSEs have no opportunity for supplemental procurement to minimize RMR designations, and it works to minimize RMR unit designations.

28. Current RA resource counting conventions are fully consistent with AB 1969's requirements.

Conclusions of Law

1. LSE-based procurement obligations to address the reliability problem caused by the Path 26 transmission constraint should be established to minimize CAISO-based procurement in SP 26 and NP 26.

2. The Path 26 Counting Constraint proposal should be adopted beginning with the 2008 compliance period, with March 22, 2007 set as the cutoff date after which new RA resource agreements would not be grandfathered for Path 26 allocation purposes.

3. The CAISO's 2008 LCR study should be approved as the basis for establishing local procurement obligations for 2008 applicable to Commission-jurisdictional LSEs.

4. Because there is no compelling information that would justify a departure from the Option 2/Category C local area reliability standard approved for 2007, that reliability standard should be adopted for setting local procurement obligations for 2008.

5. Because the current Local RA program establishes procurement obligations for the following year, LSEs should only be responsible for procurement in a local area to the level of resources that exist in the area.

6. To implement our policy that dispatchable DR programs should be counted as Local RA resources to the extent feasible, SCE and PG&E should continue working with the CEC, the CAISO, and the Energy Division so that the policy can be carried out to completion for 2008.

7. Pending a decision in R.07-01-041 that resolves questions pertaining to the coordination of emergency and interruptible DR programs and the CAISO's market design protocols, it would be premature to reverse our decision that the capacity of such DR programs should count for RA compliance filings.

8. Because over-reliance on CAISO backstop procurement is fundamentally at odds with the LSE-based procurement objective of the RA program, the 2008 Local RAR processes should be coordinated with the CAISO's backstop

procurement processes in accordance with Proposal 8 as set forth in the foregoing discussion.

9. The uncontested Energy Division proposals for clarification of the RA rounding convention for determining the QC of wind units with less than three years of performance data should be adopted.

10. The Energy Division should be authorized and directed to do the following:

a. Notify LSEs of reduced local procurement obligations for 2008, if any, that reflect any LCR reductions from the 2008 LCR study that are determined by the CAISO to be warranted.

b. Calculate and establish reduced LCRs for those areas for which the CAISO has identified a deficiency in qualifying capacity resources.

O R D E R

IT IS ORDERED that:

1. The *Joint Proposal of the California Independent System Operator Corporation, Pacific Gas and Electric Company (U 39 E), San Diego Gas & Electric Company (U 902 E), Southern California Edison Company (U 338 E), and The Utility Reform Network to Implement a Path 26 Counting Constraint in the CPUC's Resource Adequacy Program* (Joint Proposal), filed March 22, 2007, is adopted beginning with the 2008 Resource Adequacy (RA) compliance period, provided, however, that the cutoff date for "Grandfathered RA Commitments" as described in Step 2 of the Joint Proposal shall be March 22, 2007 rather than February 21, 2007.

2. The Local RA regulatory program and associated requirements adopted in Decision 06-06-064 for 2007 are continued in effect for 2008 subject to the

modifications, refinements, and Local Capacity Requirements (LCRs) adopted by this decision for 2008.

3. The "Option 2/Category C" LCRs set forth in the California Independent System Operator's (CAISO) *2008 Local Capacity Technical Analysis, Report and Study Results, Updated April 3, 2007*, filed April 4, 2007, are adopted as the basis for establishing Local RA procurement obligations for load-serving entities (LSEs) subject to this Commission's RA program and requirements, subject to the following:

a. The Energy Division may calculate and establish reduced local procurement obligations, if any, that may result from the supplemental LCR Study review process described in the foregoing opinion and as agreed to by the CAISO; and

b. The Energy Division may calculate and establish reduced local procurement obligations, if any, that may result from adjustments for resource deficiencies in particular local areas, as described in the foregoing opinion.

4. The Executive Director shall ensure that Commission staff undertakes the activities identified for staff in the foregoing discussion, findings, and conclusions.

5. This proceeding remains open for consideration of issues listed in the December 22, 2006 Phase 2 Scoping Memo that are not resolved by today's order.

This order is effective today.

Dated June 21, 2007, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

APPENDIX A

RESOURCE ADEQUACY PROGRAM SCHEDULE FOR 2007-08

Date	Entity	Event	Process
06/21/07	CPUC	Commission adopts Track 1 Decision including 2008 Local RAR	RA
07/02/07	CAISO	CAISO begins Import Allocation Process	RA
07/06/07	CPUC/ CEC	Local RAR, System RAR, and Demand Response allocations sent to LSEs	RA
07/13/07	CPUC	CPUC issues 2008 Local and System RA guides and templates for both "year-ahead" and "month-ahead" compliance filings.	RA
07/19/07	CPUC	CPUC holds teach-in regarding 2008 guides and templates	RA
07/20/07	CPUC/ CAISO	CPUC and CAISO hold workshop to increase transparency in the LCR process, and locate possible areas for refinement and coordination.	LCR
08/23/07	CAISO	CAISO completes import allocation process	RA
09/19/07	LSEs	LSEs file Preliminary Local RAR showing to accommodate RMR	RA
10/01/07	CAISO	CAISO identifies the 2007 RMR contracts to be renewed	RMR
10/05/07	CPUC	Energy Division notifies LSEs of their 2007 RMR credit for Local and System RAR.	RA
10/26/07	CAISO	CAISO hosts meet and confer regarding LCR study assumptions	LCR
10/31/07	LSEs	LSEs file Final Local RAR showing and "year-ahead" System RAR	RA
11/01/07	CAISO	CAISO analyzes demonstrations for "residual needs" due to effectiveness factors and reports back to LSEs	RCST
11/02/07	PTO	PTOs submit base cases and load forecasts to the CAISO for 2009 LCR study	LCR
12/03/07	LSEs	Last date for LSE to file amended Local RAR or System "year ahead" RAR showing to reduce CAISO backstop for collective deficiency.	RCST
After 12/03/07	CAISO	CAISO backstop procurement to cure collective local deficiencies; Energy Division notified to reallocate system credit to LSEs for monthly showings.	RA/ RCST
01/04/08	CAISO	CAISO releases 2009 Draft LCR study	LCR
01/25/08	CAISO	CAISO hosts meeting on LCR study	LCR
02/01/08	various	Parties comment on 2009 LCR study	LCR
05/01/08	CPUC	Proposed Decision on 2009 LCR	RA
06/01/08	CPUC	Final Decision on 2009 LCR	RA

(END OF APPENDIX A)