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Decision 09-06-028 June 18, 2009

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Annual Revisions to Local Procurement Obligations and Refinements to the Resource Adequacy Program.	Rulemaking 08-01-025 (Filed January 31, 2008)

DECISION ADOPTING LOCAL PROCUREMENT OBLIGATIONS FOR 2010 AND FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM

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DECISION ADOPTING LOCAL PROCUREMENT OBLIGATIONS FOR 2010 AND FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM

1. Summary

This decision establishes local capacity procurement obligations for 2010 applicable to Commission-jurisdictional electric load-serving entities. These procurement obligations are based on an annual study of local capacity requirements performed by the California Independent System Operator for 2010. For the second consecutive year, the total local capacity requirements determined by the California Independent System Operator for all local areas combined declined slightly from the prior year; the reduction is from 27,915 megawatts in 2009 to 27,727 megawatts in 2010.

In addition, this decision adopts several proposed resource adequacy program refinements. Most significantly, we revise the existing rule for counting the net qualifying capacity of intermittent wind and solar power generation. The current rule significantly overstates the dependable level of generation that is available during peak hours. To more accurately reflect the actual performance of those resources during peak load conditions, we adopt an "exceedance" method for calculating the net qualifying capacity of these resources that explicitly takes into account very large variances in output during peak periods. With the adopted exceedance factor of 70%, the qualifying capacity of a wind or solar resource would be equal to the minimum output achieved by the resource for at least 70% of the hours in the data set of historical generation for each month.

Notwithstanding our objective to increase the use of renewable resources such as wind and solar generation, as well as our objective to minimize the costs of the resource adequacy program to the extent consistent with reliable service,

we find that this modification to the resource adequacy counting rule is necessary to insure against the risk of over-reliance on the ability of these resources to provide capacity during peak demand periods.

Other modifications to the resource adequacy program that we adopt today include the following:

- We specify the conditions under which new resources that are expected to become commercially operational during the following compliance year may be counted by load-serving entities in their compliance demonstrations for local resource adequacy procurement.

- The allocation of "Cost Allocation Methodology" capacity credits to load-serving entities that was ordered by the Commission in Decision 07-09-044 will be performed on a monthly basis under specified circumstances.

- Resource adequacy capacity credits associated with certain demand response programs will be allocated to load-serving entities using load impact protocols adopted in Decision 08-04-050. Also, we provide for greater transparency in how this allocation process is implemented.

- The rule for counting the net qualifying capacity of resources whose capacity value is calculated using a rolling average of historical performance is modified to account for scheduled outages during the averaging period.

2. Procedural Background

Phase 1 of this proceeding was concluded with the issuance of Decision (D.) 08-06-031 on June 27, 2008. The *Assigned Commissioner's Phase 2 Ruling and Scoping Memo* (Phase 2 Scoping Memo), issued on September 15, 2008, identified the issues to be considered in Phase 2 as well as the procedure and schedule for their consideration. Two broad categories of issues were established. The first category, local resource adequacy (RA) issues, pertains to the California Independent System Operator's (CAISO) 2010 local capacity requirements (LCR) study as well as this Commission's establishment of local procurement obligations for 2010 based on the LCR study. The second category, program refinement issues, pertains to various proposals to modify the RA program.

The Commission's Energy Division facilitated workshops on RA program refinement issues on October 6, 2008 and on January 22-23, 2009. In connection with the January workshops, parties were permitted to serve workshop proposals on January 9, 2009. Energy Division issued a workshop report on February 6, 2009. Comments on these issues were filed on February 17, 2009 by Alliance for Retail Energy Markets (AReM); CAISO; California Wind Energy Association, American Wind Energy Association, and Solar Alliance (CalWEA/AWEA/SA); California Large Energy Consumers Association (CLECA), Division of Ratepayer Advocates (DRA); Dynegy Morro Bay, LLC, Dynegy Moss Landing, LLC, Dynegy Oakland, LLC, and Dynegy South Bay, LLC (Dynegy); Large-Scale Solar Association (LSA); NRG Energy, Inc. (NRG); Pacific Gas and Electric Company (PG&E); Southern California Edison Company (SCE); San Diego Gas & Electric Company (SDG&E); Sempra Energy Solutions, LLC (SES); Sempra Generation; and The Utility Reform Network (TURN). AReM; CAISO; CalWEA/AWEA/SA; DRA; Dynegy; EnerNOC, Inc. (EnerNOC); LSA; PG&E; SCE; SDG&E; SES; and TURN filed replies on February 27, 2009.

On March 23, 2009, the Energy Division published a report (2008 Resource Adequacy Report) summarizing the RA program experience for 2008 with the intention of providing factual information relevant to current RA rulemakings, including this proceeding. By joint motion filed on April 14, 2009, SCE, PG&E, and TURN requested that the Energy Division's 2008 RA report be made a part of record. No responses were filed. We will grant the motion as the report provides information relevant to the issues in Phase 2.

Following a stakeholder process that began in 2008, on May 1, 2009, the CAISO posted its "2010 Local Capacity Technical Analysis, Final Report and Study Results" (2010 LCR Study) on its website, served notice of the report's availability, and filed it with the Commission. To accommodate the CAISO's LCR study schedule and associated stakeholder review process, the Phase 2 Scoping Memo deferred the dates for comments and reply comments on Local RA issues to May 8 and May 12, 2009, respectively. AReM and SCE filed comments regarding the LCR study and the establishment of local procurement obligations for 2010. Replies were filed by the CAISO, DRA, and PG&E.

3. Local RA for 2010

3.1. 2010 LCR Study

D.06-06-064 determined that a study of local capacity requirements performed by the CAISO would form the basis for this Commission's Local RA program. The CAISO conducts its LCR study annually, and this Commission resets local procurement obligations each year based on the CAISO's LCR determinations. As noted above, the CAISO issued its final LCR report and study results for 2010 on May 1, 2009.

The CAISO states that the assumptions, processes, and criteria used for the 2010 LCR study were discussed and recommended in a stakeholder meeting held on November 3, 2008, and that, on balance, they mirror those used in the 2007, 2008, and 2009 LCR studies. The CAISO identified and studied capacity needs for the same ten local areas as in the previous study: Humboldt, North Coast/North Bay, Sierra, Greater Bay, Greater Fresno, Big Creek/Ventura, Los Angeles Basin, Stockton, Kern, and San Diego.

The 2009 and 2010 summary tables in the 2010 LCR report, copied below, show that for all ten areas combined, the total LCR associated with reliability Category C declined from 27,915 megawatts (MW) in 2009 to 27, 727 MW in 2010. The existing capacity needed increased from 27,008 MW in 2009 to 27,075 MW in 2010. LCR needs decreased in the Sierra and Stockton areas mainly due to new transmission projects, and decreased in the Humboldt, Bay Area, Fresno, and Kern areas where the load trend is downward. LCR needs increased slightly in the North Coast/North Bay, Los Angeles Basin, and Big Creek/Ventura areas mostly due to load growth. The San Diego area LCR need increased partly because of load growth and partly because of the new Otay Mesa generating facility becoming the biggest single generation contingency in the area.

2010 Local Capacity Requirements

	Qualifying Capacity			2010 LCR Need Based on Category B			2010 LCR Need Based on Category C with operating procedure		
Local Area Name	QF/ Muni (MW)	Market (MW)	Total (MW)	Existing Capacity Needed	Deficiency	Total (MW)	Existing Capacity Needed	Deficiency	Total (MW)
Humboldt	48	135	183	176	0	**176**	176	0	**176**
North Coast / North Bay	149	736	885	787	0	**787**	787	3	**790**
Sierra	1066	769	1835	1133	102	**1235**	1717	385	**2102**
Stockton	229	266	495	357	0	**357**	432	249	**681**
Greater Bay	1096	5608	6704	4224	0	**4224**	4651	0	**4651**
Greater Fresno	502	2439	2941	2310	0	**2310**	2640	0	**2640**
Kern	656	9	665	187	0	**187**	403	1	**404**
LA Basin	3918	8212	12130	9735	0	**9735**	9735	0	**9735**
Big Creek/ Ventura	947	4146	5093	3212	0	**3212**	3334	0	**3334**
San Diego	205	3502	3707	3200	0	**3200**	3200	14	**3214**
Total	**8816**	**25822**	**34638**	**25321**	**102**	**25423**	**27075**	**652**	**27727**

2009 Local Capacity Requirements

	Qualifying Capacity			2009 LCR Need Based on Category B			2009 LCR Need Based on Category C with operating procedure		
Local Area Name	QF/ Muni (MW)	Market (MW)	Total (MW)	Existing Capacity Needed	Deficiency	Total (MW)	Existing Capacity Needed	Deficiency	Total (MW)
Humboldt	48	135	183	177	0	**177**	177	0	**177**
North Coast / North Bay	217	728	945	766	0	**766**	766	0	**766**
Sierra	1012	768	1780	1453	226	**1679**	1617	703	**2320**
Stockton	276	265	541	491	34	**525**	541	185	**726**
Greater Bay	1111	5662	6773	4791	0	**4791**	4791	0	**4791**
Greater Fresno	510	2319	2829	2414	0	**2414**	2680	0	**2680**
Kern	646	31	677	208	0	**208**	417	5	**422**
LA Basin	3942	8222	12164	9728	0	**9728**	9728	0	**9728**
Big Creek/ Ventura	931	4201	5132	3178	0	**3178**	3178	0	**3178**
San Diego	201	3442	3663	3113	0	**3113**	3113	14	**3127**
Total	**8894**	**25773**	**34687**	**26319**	**260**	**26579**	**27008**	**907**	**27915**

The comments reveal no disagreement with CAISO's LCR determinations for 2010. As we noted in D.08-06-031, it appears that past efforts towards greater transparency and opportunity for participation in the LCR study process have paid off in significant part, as reflected in the comments. We determine that the CAISO's final 2010 LCR study should be approved as the basis for establishing local procurement obligations for 2010 applicable to Commission-jurisdictional LSEs.

SCE noted that for the 2010 LCR study, the CAISO coordinated with the California Energy Commission (CEC) to obtain a revised 2010 peak load demand forecast that incorporates the effects of the current economic downturn. SCE urges continuation of this practice, and asks that we encourage such coordination going forward. DRA supports this recommendation. We concur that load forecasts should be as-up-to date as reasonably possible, consistent with the orderly administration of the RA program.

3.2. Local Procurement Obligations for 2010

3.2.1. Continuation of the Local RA Program

D.06-06-064 adopted a framework for Local RA and established local procurement obligations for 2007 only. D.07-06-029 and D.08-06-031 established local procurement obligations for 2008 and 2009, respectively. We intend that Local RA program and associated regulatory requirements adopted in those decisions shall be continued in effect for 2010, subject to the 2010 LCRs and procurement obligations adopted by this decision.

In previous decisions, we delegated ministerial aspects of RA program administration to the Commission's Energy Division. The Energy Division should implement the local RA program for 2010 in accordance with the adopted policies and principles.

3.2.2. Reliability Options

The 2010 LCR report sets forth two sets of LCRs associated with reliability options based on North American Electricity Reliability Council (NERC) Performance Level B and Performance Level C criteria. As the CAISO's report explains:

> 1. **Option 1 – Meet Performance Criteria Category B.**
> Option 1 is a service reliability level that reflects generation capacity that must be available to comply with reliability standards immediately after a NERC Category B given that load cannot be removed to meet this performance standard under Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the only means of meeting any Reliability Criteria that is beyond the loss of a single transmission element (N-1). These situations will likely require substantial load interruptions in order to maintain system continuity and alleviate equipment overloads prior to the actual occurrence of the second contingency.
>
> 2. **Option 2 – Meet Performance Criteria Category C and Incorporate Suitable Operational Solutions.**
> Option 2 is a service reliability level that reflects generation capacity that is needed to readjust the system to prepare for the loss of a second transmission element (N-1-1) using generation capacity *after* considering all reasonable and feasible operating solutions (including those involving customer load interruption) developed and approved by the CAISO, in consultation with the [Participating Transmission Owners (PTOs)]. Under this option, there is no expected load interruption to end-use customers under normal or single contingency conditions as the CAISO operators prepare for the second contingency. However, the customer load may be interrupted in the event the second contingency occurs.
>
> As noted, Option 2 is the local capacity level that the CAISO requires to reliably operate the grid per NERC, [Western Electric Coordinating Council (WECC)], and CAISO standards. As such,

> the CAISO recommends adoption of this Option to guide resource adequacy procurement. (2010 LCR Report, p. 15; emphasis in original.)

D.06-06-064 determined that the reliability level associated with Option 2 as defined in the 2007 LCR study should be applied as the basis for local procurement obligations for that year. 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 [resource adequacy requirements] for 2008 and beyond." (D.06-06-064, p. 21.) D.07-06-029 and D.08-06-031 adopted Option 2 as recommended by the CAISO for 2008 and 2009 local procurement obligations. There is no evidence or recommendation before us suggesting that assumption of the reduced reliability associated with Option 1 is reasonable for 2010. We therefore affirm the continued application of Option 2 to establish local procurement obligations for 2010.

3.2.3. Aggregation of Local Areas

To address supplier market power concerns, D.06-06-064 established an approach for aggregation of certain local areas for 2007. After determining each LSE's allocation of Local RAR for each local area based on its share of load in the investor-owned utility (IOU) distribution service area, the Commission 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 RA compliance. D.07-06-029 and D.08-06-031 found that continuation of the aggregation approach for these six areas was reasonable for 2008 and 2009, respectively.

No party has raised a concern that reliability would be impaired by continuing the approach for 2010. We find it is reasonable to continue the previously adopted aggregation approach for 2010.

3.2.4. Local Area Resource Deficiencies

The LCR study identifies deficiencies in qualifying capacity resources in certain local areas. In the 2010 study, for performance Category C, the CAISO determined that such deficiencies exist in the Sierra, Stockton, Kern, and San Diego local areas. The total of such area deficiencies for 2010 is 652 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, at 21-22.) D.06-06-064 authorized this "blanket waiver" treatment of deficiencies for 2007 only, and subsequent decisions have approved such waivers on a year-to-year basis. We will again approve such blanket waiver of the local procurement requirement in the resource-deficient areas identified by the CAISO.

3.2.5. Coordination with CAISO Backstop Procurement

In the previous local RA decisions we have established local RA compliance filing procedures in coordination with the CAISO's Reliability Must Run (RMR) mechanism. To minimize unnecessary procurement, we established an iterative process whereby load-serving entities (LSEs) submitted preliminary showings in September that the CAISO would consider before making RMR commitments. The final compliance showings were made due on October 31, and the System RA compliance filing date was reset to October 31 as well.

In an April 14, 2009 stakeholder meeting, the CAISO advised stakeholders that its tariff requires it to identify collective effectiveness deficiencies in local capacity areas at least 60 days prior to the beginning of the RA compliance year, i.e., on November 2, 2009 for the 2010 compliance year. To make this identification, CAISO staff needs local procurement information submitted by Commission-jurisdictional LSEs. CAISO staff indicated to participants in that stakeholder meeting that the final local RA showings for 2010 would need to be advanced to early October. Although the CAISO did not submit a proposal to this Commission to change the historical filing procedure, AReM and SCE commented on the scheduling issue. In its reply comments, the CAISO stated that it agrees to issue a revised deficiency notice in mid-November that reflects the final procurement information provided by LSEs on October 31. The CAISO also asks that the Commission encourage all LSEs to submit as much procurement information as they have by no later than October 9, 2009 so that the CAISO can incorporate it into the November 2 Local Capacity Area deficiency notice. With this procedure, it is not necessary to significantly revise the filing dates that have been applied in the local RA program. We are informed by our Energy Division staff that a minor shift would better enable processing the information in the compliance filings.

Accordingly, for the 2010 compliance cycle, preliminary local procurement showings shall be made on September 18, 2009 and final compliance showings for both local RA and System year-ahead RA shall be due on October 29, 2009. In addition, we incorporate the CAISO's proposal to encourage advance reporting by October 9 by authorizing the Energy Division to initiate an optional supplemental reporting procedure for that purpose.

D.07-06-029 approved a procedure (Proposal 8) for integrating the Commission's RA and the CAISO's procurement procedures, and D.08-06-031 found that it would be reasonable and appropriate to implement the Proposal 8 procedure in 2009. We will again provide that this procedure should be implemented for 2010, with appropriate scheduling adaptations as determined by the Energy Division, and with the CAISO only designating units with 2009 RMR contracts that were not under RA contracts in the preliminary RA compliance filings.

4. Resource Adequacy Program Refinements

4.1. Net Qualifying Capacity (NQC) List

The Energy Division made a workshop proposal to post the NQC list that will be used for compliance purposes on the Commission's and/or the California Energy Commission's website. The Energy Division reports that no parties expressed concern about this proposal and that some parties favored it. AReM, DRA, and PG&E supported the proposal in their filed comments. AReM notes that when the CAISO updates the NQC list, it often removes the previous list, making unclear to LSEs which NQC values to use for their RA showings.

Discussion

It should be clear to LSEs what NQC values the Energy Division will apply in its review of LSEs' compliance filings. We therefore endorse this proposal. We concur with the Energy Division that that this is a ministerial action that is within the province of the Energy Division to carry out.

4.2. Local RA Credit for New Resources

In Phase 1 of this proceeding, PG&E proposed that new resources that have not reached commercial operation may be counted toward local RA obligations if the LSE demonstrates local procurement sufficient to cover the obligation in the months preceding the expected commercial operational status of the new resource. PG&E also proposed a stipulation that any LSE relying on a new resource for local RA needs would be responsible for replacing the capacity if the new resource's commercial operational date is delayed. PG&E characterized its proposal as interim, and the Phase 1 decision (D.08-06-031) adopted it for 2009 only. The decision included a provision that an LSE that relies on a new resource that has not become commercially operational as of the date of its final annual local RA compliance showing shall, in such showing, (1) claim the entire new resource and (2) show a single local unit that it will show on every monthly filing to make up the capacity until the new unit has reached commercial operational status.

In the Phase 2 workshops, Energy Division, CAISO, SDG&E, and PG&E proposed to make the interim rule permanent. TURN and other workshop participants suggested that the requirement that a single substitute unit must be shown until the new unit is available is unnecessary and may have an unintended consequence of delaying the retirement of certain older units in some local areas. Instead, these parties believe that LSEs should be allowed to use multiple substitute units in their compliance showings. CAISO, DRA, NRG, PG&E, SDG&E, and TURN filed comments generally supporting continuing the interim rule for counting new resources. Four of these parties (DRA, PG&E, SDG&E, and TURN) proposed that the provisions for claiming the entire new unit and requiring a single substitute unit be eliminated or revised.

Discussion

We will make the interim rule for new resources permanent. As SDG&E points out, the local RA compliance demonstration is made only once a year. In the absence of this program refinement, new capacity could remain uncounted for up to 11 months, unnecessarily driving up costs. We will delete the provision that the LSE must claim the entire new resource and show a single local substitute unit. Allowing only one LSE to claim capacity from a new unit could undermine efficient trading of local resources by inhibiting the owner of the new resource from laying off excess capacity to a capacity-deficient LSE. Requiring that the substitute capacity come from a single resource in the local area would reduce the options available to the LSE for fulfilling its compliance obligation, which would further drive up costs

4.3. Cost-Allocation Methodology (CAM) Credit Allocations

In Phase 1 of this proceeding, AReM sought to change the quarterly allocation of CAM-related RA credits that was ordered by D.07-09-044 to a monthly allocation. During the Phase 1 workshops, most parties agreed that the existence of just one CAM contract in force at that time did not justify the administrative costs of a move to monthly allocations. The Phase 1 workshop discussions then centered on defining the threshold for determining when the change from quarterly to monthly allocations would be justified.

AReM proposed in Phase 1 that the trigger for changing to monthly allocations of RA credits be defined as the date that one additional CAM contract becomes operational. D.08-06-031 noted that this was a straightforward proposal that was not contested by any party, but declined to adopt it in light of unresolved workload issues noted by the Energy Division. The Commission deferred the issue to Phase 2 for resolution.

In the Phase 2 workshops the Energy Division proposed that the switch to a monthly allocation of CAM credit should be triggered when an individual service territory has two or more operational CAM contracts. Service territories with one operational CAM contract would continue to have quarterly reallocations of CAM credits. The Energy Division also proposed that if a reallocation would result in no change greater than 0.5 MW for any LSE, CAM credits would not be reallocated that month. In their filed comments, AReM, DRA, and SCE support the Energy Division proposal, and PG&E does not oppose it.

Discussion

We will adopt the Energy Division proposal for allocating CAM credits, as it strikes a reasonable balance between fairly allocating CAM credits and avoiding additional administrative burdens on the Energy Division.

4.4. Maximum Cumulative Capacity (MCC) Buckets

As explained in the Energy Division's Phase 2 workshop report, MCC "buckets" were established early in the RA program to ensure that LSEs do not over-rely on resources with limited availability to the point that CAISO would not be able to reliably operate the grid with RA resources.[1] The buckets represent the maximum cumulative percentage of an LSE's procurement obligation that can be met with use-limited resources (ULRs) and RA contracts that provide less than "7x24" hours per week availability.[2]

In its workshop proposal, AReM recommended eliminating the requirement to categorize RA resources into MCC buckets. AReM noted several changes to the RA program that have occurred since the MCC bucket approach

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[1] D.05-10-042, Section 7.1, at 43-51.

was established: the ability to count liquidated damages (LD) contracts has been phased out of the RA program, the CAISO tariff requires ULRs to submit monthly use plans, and NQC counting conventions for intermittent resources are under review. AReM contends that these changes justify the elimination of the MCC buckets and associated compliance checks. At the workshop, several parties expressed opposition to AReM's proposal, and no consensus was reached.

In its filed comments, AReM notes that MCC data provided by LSEs have not been used for any purpose except for checking that the data have been provided and comply with the rules. AReM notes in particular that the CAISO had originally pressed for the MCC bucket approach yet it does not use the data. AReM also disputes the view advanced by LSA that MCC buckets are necessary to recognize the capacity value of ULRs. Finally, AReM requests that if the MCC bucket approach is continued, a column be added to the NQC list to identify the MCC category attributable to each resource to ease the filing burden and reduce the potential for filing errors.

Along with AReM, DRA and NRG filed comments in support of eliminating the MCC bucket approach. CAISO, Dynegy, LSA, SCE, and SDG&E opposed the proposed elimination in their filed comments and/or reply comments. PG&E noted the need to coordinate the MCC bucket provision with the RA counting rules. PG&E would not support elimination of the MCC bucket approach if, as suggested by the Energy Division, such elimination would mean

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[2] Some resources, because of fuel limitations, limits on annual emissions, and similar constraints, are capable of generating only limited amounts of energy during the course of the year.

that energy contracts that call for delivery or provide dispatch rights during less than all hours of the year could no longer be used to comply with RA procurement obligations. TURN stated no strong preference with respect to this issue but noted that the CAISO's most recent draft Standard Capacity Product (SCP) does not include any reference to MCC buckets.

Discussion

In adopting the MCC approach, D.05-10-042 noted that it was proposed to alleviate over-reliance on ULRs that could not be counted on to serve a large portion of a month outside of the peak period. (D.05-10-042, at 44.) Thus, the MCC bucket approach can be seen as an important reliability measure. As SDG&E notes, if too many ULRs are included in the RA mix, there arises at least a theoretical possibility that the CAISO-operated system could become energy deficient, especially in years when imported hydro generation is low, weather is hotter than normal, and one or more nuclear plants have unexpected outages. The MCC bucket approach can also be seen as a cost-saving measure because it allows for the prudent use of ULRs to make up the RA fleet.

One alternative to the MCC bucket approach would be adopt the Energy Division's interpretation that elimination of the MCC buckets would mean, for example, that 6x16 energy contracts would no longer count for RA. Another alternative would be to accept RA compliance showings without regard to any use limitations on resources nominated by the LSEs in fulfillment of their capacity procurement obligations. We are concerned that the first alternative would unnecessarily exclude significant amounts of reliable capacity from the RA program and lead to excessive procurement costs, while the second alternative could lead to significant reliability concerns.[3] At this time, we are not aware of any additional alternatives, although we note SDG&E's observation that a better tool designed by the CAISO may eventually replace the MCC buckets.

Nothing in the record of this proceeding assuages our concerns about eliminating the MCC bucket approach at this time. In particular, we do not find the phase-out of LD contracts, the fact that the CAISO tariff requires ULRs to submit monthly use plans, or the fact that the counting rule for intermittent resources is under review to be evidence that reliability concerns surrounding ULRs have been adequately resolved. The phase-out of LD contracts has no impact on resources with physical use limitations, the monthly plans submitted by ULRs are informational, and it is at best premature to base elimination of the MCC buckets on the current review of the counting rules for intermittent resources. Finally, the fact that the CAISO has not made direct use of the MCC data contained in the LSE filings may be somewhat puzzling but it does not mean that our decision to limit reliance on ULRs for RA purposes lacks important reliability benefits. Accordingly, we will leave the MCC bucket requirement in place.

We find AReM's request that a column be added to the NQC list to identify the MCC category attributable to each resource to be a potentially worthwhile suggestion that could improve the RA compliance filing process. We

[3] The reliability concern would undoubtedly be translated into a cost concern. The CAISO anticipates that in the event that the MCC bucket requirement is eliminated and not replaced with a comparable mechanism, its use of the Residual Unit Commitment Mechanism, Exceptional Dispatch, and the Interim Capacity Unit Commitment Mechanism would be more frequent.

therefore urge the Energy Division and the parties to explore with CAISO whether this suggestion is feasible and, if it is, how it might be implemented.

TURN's observation that CAISO's draft SCP omits any reference to MCC buckets raises an issue that needs to be considered in further development of the SCP and/or RA program modifications that may be needed to coordinate the RA program with the SCP tariff.

4.5. Demand Response (DR) Resources

4.5.1. DR Counting Conventions

In accordance with earlier RA decisions, dispatchable DR resources are allowed to count for purposes of RA compliance.[4] However, DR resources are not treated in the same manner as generation resources. Among other things, they do not currently appear on the NQC list. As part of the annual RA compliance reporting cycle, Energy Division staff performs the ministerial function of calculating DR program impacts and allocating DR capacity credits to all LSEs pursuant to Commission-adopted policy.

D.08-04-050 adopted load impact (LI) protocols for DR resources, and Energy Division staff proposed to use the adopted protocols as RA counting rules for DR capacity. Staff also proposed to list DR programs on the NQC list for information only. This proposal would apply both to DR programs controlled by IOUs and non-IOU controlled DR programs. For those IOU DR programs for which funding has been approved by the Commission, staff would use the underlying load impacts associated with that approval. For non-IOU DR programs that do not involve Commission approval, the LI protocols would

[4] D.04-10-035 at 26-27; D.05-10-042 at 51-54.

serve as NQC counting rules, and the DR program operator along with the LSE that wishes to count the program would provide information comparable to the protocols. Energy Division would then determine the NQC of the program. Finally, staff proposed to use other protocols if appropriate. At the workshops, staff clarified that the intent is to use the adopted LI protocols to the greatest extent possible. Alternative protocols would only be used for new DR programs that do not have Commission-approved LI protocols.

With staff's clarification that it would use the LI protocols to the greatest extent possible, DRA, PG&E, SCE, and SDG&E support the staff's proposal. AReM agrees that those seeking RA credit for DR programs should be obligated to provide information to verify RA capacity, and that there should be a reasonable standard for measurement and verification that all DR programs should meet. Nevertheless, AReM has serious concerns about application of the LI protocols to non-IOU DR programs. As AReM sees it, the LI protocols were developed to determine the cost-effectiveness of IOU DR programs and for long-term resource planning, and are not appropriate for evaluating non-IOU DR programs. AReM contends that cost-effectiveness is unrelated to independently-funded DR programs. Moreover, according to AReM, the LI protocols would be burdensome and expensive obligations that would discourage electric service providers (ESPs) from developing their own programs. AReM also notes that the CAISO has begun a stakeholder process that will address measurement and verification requirements for DR resources, and suggests that those requirements will provide appropriate standards for determining the NQC of RA capacity for non-IOU DR programs. In light of the foregoing, AReM proposes flexible compliance that would allow each non-IOU DR program provider to submit a proposal for counting the RA capacity of its

DR program that complies with the measurement and verification requirements of the CAISO. EnerNOC filed reply comments stating concerns similar to those raised by AReM.

Discussion

We are intrigued that the CAISO is developing tariff standards for measurement and verification of DR resource performance, and we look forward to an opportunity to evaluate whether such standards, once adopted, would be appropriate for use in the RA program. However, we cannot commit prospectively to using such standards. At this time, staff's proposal to use the LI protocols for assessing DR impacts provides a means of evaluating DR programs with the use of a defined, uniform standard for all programs, and we therefore approve it. We note that AReM agrees there should be a standard "that all such programs must meet to obtain an RA credit." (AReM Comments, at 3.) Yet, AReM would have the LI protocols apply to IOU DR programs but not other DR programs.

In their discussion of D.08-04-050, AReM and EnerNOC emphasize the role that cost-effectiveness analysis plays with respect to the LI protocols. It is true, as AReM observes, that the Commission found that LI estimates are necessary for analysis of the cost-effectiveness of DR programs and for long-term resource planning. (D.08-04-050, Finding of Fact 1.) However the Commission also found that LI protocols improve consistency and accuracy in the calculation of DR load impact estimates. (*Id.*, Finding of Fact 2.) We believe that improved consistency and accuracy in the calculation of DR load impact estimates would benefit the RA program by giving appropriate weight to the capacity value of these resources. Moreover, D.08-04-050 explicitly stated that evaluations based on the LI protocols may be of use in other proceedings, including RA proceedings. (D.04-08-050, at 28. Further, it directed the IOUs to use the protocols in estimating DR impacts for RA purposes unless directed otherwise by the Administrative Law Judge (ALJ) or assigned Commissioner in the relevant proceeding. (*Id.*, Ordering Paragraph 5.)

We are mindful of AReM's concern that the application of the LI protocols could be burdensome and expensive for DR providers and ESPs, just as we presume it would be for IOUs. As noted above, the CAISO's development of a measurement and verification standard may turn out to be a promising approach that could be used for the RA program. For now, however, the alternative to adopting a clear and defined standard (such as the LI protocols) that can be delegated to the Energy Division for implementation as a ministerial function would be to conduct formal Commission proceedings to review and determine the load impacts of DR programs. This could raise timing problems in the administration of the RA compliance filing cycle.

We do find that it would be appropriate for Energy Division to convene an educational workshop and/or publish guidelines to describe and explain the process and criteria that will be used to apply the adopted LI protocols and we direct that it do so. Finally, we concur with SDG&E's recommendation that the Energy Division should provide notice in the appropriate RA proceeding whenever it seeks to alter application of the LI protocols in determining the NQC for a particular DR resource.

4.5.2. Transparency in Allocation of DR Credits

PG&E and TURN jointly submitted a workshop proposal to address what they see as a lack of transparency in the DR allocation process. They initially recommended that the Commission publish an explicit accounting of how the RA megawatts associated with each DR program are allocated to specific LSEs at the same time that LSEs are notified of their respective allocations. The workshop discussions yielded suggestions that DR credit allocations should be provided to LSEs on a program-specific basis and that draft allocations should be shared with LSEs before final allocations are provided. This would allow LSEs to raise any concerns about the allocation with staff. Workshop participants raised a confidentiality concern, and PG&E revised its proposal to provide that the program-specific and total DR allocations to an LSE should only be shared with that LSE.

Staff suggested in its post-workshop report that publishing the total qualifying capacity of DR programs on a program-specific basis would increase transparency in a way consistent with the parties' suggestion. Staff also suggested that DR allocations could include the distribution area coincident peak load-share percentage used for the LSE and a list of the DR programs allocated using that load-share. Finally, staff noted that providing draft allocations, conferring with LSEs, and then issuing final allocations could delay the date of final allocations.

Parties generally supported the need for greater transparency in their filed comments. AReM reiterated the workshop discussion regarding the need to respect confidentiality of certain data, and would oppose the public posting of LSE-specific allocations. AReM believes that the total RA credits assigned to each IOU DR program should be publicly available. PG&E proposed that the Commission provide clear justification for any reductions made in the RA capacity associated with any specific DR program

With respect to the proposal that staff provide preliminary allocation information to LSEs and provide opportunity for discussion before final allocations are assigned, AReM notes that specific DR allocations are provided to individual LSEs relatively late in the RA compliance cycle. AReM therefore opposes the preliminary review process if it would cause any additional delay. PG&E supports providing LSEs an opportunity to review and discuss preliminary allocations with the expectation and understanding that any delay in making the final assignment would be modest. SCE would support such a process if it would not delay the DR allocations beyond the historical release date of early July, while SDG&E believes the possible delay may be worth the benefit. TURN also believes that the Commission should err on the side of caution and provide for preliminary review, and notes that this could avoid disputes that could lead to even greater delay.

Discussion

To promote fairness and confidence in the RA program, the DR capacity credit allocation process should be transparent to the maximum extent consistent with Commission policy regarding confidentiality of electric procurement data made in D.06-06-066 and subsequent decisions in the underlying rulemaking (R.05-06-040). This includes making public information about the process and criteria used by the staff to administer the program as well as any actual data used in the allocation process where such disclosure would not reveal market-sensitive information.

The PG&E/TURN transparency proposal, clarified to provide that LSE-specific allocations and supporting information should be provided only to the LSE and not made public, would provide greater understanding and should be adopted. Staff's suggestion to provide individual LSEs with the distribution area coincident peak load-share percentage used for the LSE and a list of the DR programs allocated using that load-share is consistent with this approach and is therefore also approved. Staff's proposal to publish the total RA capacity associated each DR program (which AReM supports) would likewise promote transparency and is therefore approved. LSE-specific allocations and the total for each program type should be disclosed to the LSE at the level of aggregated local areas.

Balancing the need for greater transparency and accuracy in allocations, on the one hand, and the need for timely assignment of final DR capacity credit allocations, on the other hand, we find that limited provision should be made for preliminary notice to LSEs of assignments of credits. As SCE points out, the staff has targeted the assignment date in early July of the applicable compliance year. We believe a modest extension, not to exceed 15 days, could be added to the DR credit assignment process to accommodate an opportunity for expedited review based on preliminary assignment notices. Authority to grant such an extension is appropriately delegated to the Energy Division.

4.5.3. DR Credit Allocation Method

Energy Division staff assigns DR program capacity credits based on the established principle that DR impacts should be allocated to LSEs in proportion to the funding that their respective customers provide toward DR programs. (D.05-10-042 at 38.) PG&E and TURN submitted a workshop proposal that the credits associated with IOU DR programs whose costs are recovered in Energy Resource Recovery Account (ERRA) should be allocated exclusively to the IOUs that administer them. The reasoning is that since DR programs whose costs are recovered through the ERRA are paid by bundled service customers exclusively, the same customers should receive the RA benefits of those programs.

AReM proposed that DR credits should be allocated to LSEs based on the shares of bundled and direct access (DA) participants in an IOU's DR program. The IOU would receive credit for the share of bundled participants and ESPs would receive the DA customer share. Among ESPs, credit would be allocated on a load-share basis. AReM notes that commercial and industrial customers are the predominant participants in DR programs and that DA penetration is higher in these customer classes. AReM argues that these customers are disadvantaged by the current method. Several workshop participants responded that AReM's proposal is inequitable because customers that enroll in DR programs are paid for their participation in the program.

AReM reiterated its proposal in its filed comments. CLECA, DRA, PG&E, SCE, SDG&E, and TURN argued for retention of the "who pays" allocation principle.

Discussion

We affirm the established principle that DR program capacity credits should be allocated to LSEs in proportion to the funding that their respective customers provide toward DR programs. The proposed alternative of basing the allocation on relative participation rates of bundled and DA customers in a DR program fails to account for the fact that customers decide to enroll in DR programs because of the direct benefits of doing so. Since bundled service ratepayers generally provide funding for those DR program benefits, they effectively procure DR capacity. It would be inequitable to bundled service customers to assign DR capacity credits to LSEs on the basis of who participates in the DR program, without regard to how it is funded.

The PG&E/TURN proposal to allocate DR credits associated with IOU DR programs whose costs are recovered in ERRA exclusively to the IOUs that administer them, along with PG&E's clarification that credits for DR programs whose costs are recovered through distribution rates should be allocated on a load share basis, are consistent with our adopted allocation principle, reflect current practice, and are hereby affirmed.

4.6. Qualifying Facility (QF) Outage Counting

D.06-07-031 adopted a protocol for determining how the NQC of resources with scheduled outages should be counted. In Phase 1 of this proceeding, PG&E raised a concern that the protocol results in scheduled outages being counted twice in assessing the RA value of certain resources, such as QFs, that utilize historic performance as the basis for setting their NQC. As PG&E explained in Phase 1, the initial NQC calculation for these resources reflects their reduced generation during scheduled outages taken in the three-year historic averaging period. The scheduled outages of these units are applied a second time to reduce their RA counting value under the protocol. The Phase 1 decision (D.08-06-031) found that the double counting of outages for these resources should be corrected to avoid unnecessary procurement, but did not find that the proposed solution was ready for adoption. Instead, it deferred this topic to Phase 2.

CAISO and the three IOUs (PG&E, SCE, and SDG&E) jointly submitted a workshop proposal with a method to remove scheduled outages from the data used to calculate the NQC of non-dispatchable QF units whose NQC is currently based on a three-year rolling average of energy production. Under this proposal, CAISO would provide data on historical outages subject to the scheduled outage counting criterion to the California Energy Commission (CEC). The CEC would then substitute proxy data for the hours of the scheduled outage. This proxy data would be calculated by averaging the same hours for the other two years of data used in the overall NQC calculation. The NQC calculation would then be completed based on the current counting rules. This proposal would not modify the scheduled outage counting criterion.

At the workshop, staff suggested that it would be reasonable to include all units that are subject to the three-year rolling average counting convention within this proposal. Staff does not believe that the contract type (i.e., QF or renewable) justifies different treatment in this regard. CAISO and IOU representatives tentatively agreed to this modification during the workshop discussions.

The CAISO and the IOUs affirmed their support for the proposal in their filed comments. However, the CAISO conditioned its support on a Commission decision to retain the existing replacement rule for scheduled outages set forth in D.06-07-031, Section 3.1. DRA and TURN also support the proposal. No party objects to the Energy Division proposal to extend the proposed method to any resource type for which a rolling average is used to calculate NQC values, and the proposed extension is supported by DRA, PG&E, SCE, SDG&E, and TURN.

Discussion

With the clarification that it should apply to all resource types whose NQC is calculated using a rolling average, not just QF resources, the proposed "Historical Output Correction" method for correcting the double counting of outages fairly and adequately resolves our concern that such double counting could lead to unnecessary procurement. We therefore adopt it. We make this determination irrespective of the CAISO's stated condition for its support. As TURN points out, we are revising the counting rule for resources whose NQC is based on a rolling average in order to treat such resources more consistently with resources whose NQC is not de-rated for past scheduled outages. Whether to modify the replacement requirement is a separate issue.

4.7. Load Forecasting Issues

4.7.1. Year-Ahead Forecasting Method

D.05-10-042 confirmed the previously established "best estimate" approach in lieu of the "current customer" approach to year-ahead load forecasting. It also indicated a willingness to revisit the determination at an appropriate time.[5] The Phase 2 Scoping Memo noted that parties have continued to express concern that some LSEs may systematically under-forecast their load using the best estimate approach, and invited proposed solutions. It also provided that parties making such proposals should show that the conditions for revisiting the topic set forth in Section 6.1 of D.05-10-042 have been met.

AReM submitted a workshop proposal to continue the best estimate approach unless there is evidence of significant under-forecasting by LSEs. AReM observed that even if there is under-forecasting, staff has enforcement authority to seek penalties for the offending LSE. AReM also noted that the conditions for revisiting the issue set forth in D.05-10-042 have not yet been met.

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[5] The best estimate approach, adopted by D.04-10-035, requires LSEs to submit load forecasts using their best estimates of future customers and their loads. The current customer approach would require LSEs to assume that their customer base will remain fixed for the forecast period, i.e., that load migration will not occur. D.05-10-042 denied a petition for modification in which TURN sought to reverse the determination and adopt the current customer approach. D.05-10-042 noted that an organized capacity market might provide LSEs with a means of addressing the impact of load migration on their RA obligations, and stated the conditions for revisiting the topic:

> "In particular, if a capacity market is in place and it has been shown that the load migration problem can be readily addressed by the ability of LSEs to acquire and dispose of increments of capacity sufficiently small (and located where needed) to match such migration, then it would be reasonable to revisit this topic." (D.05-10-042 at 35-36.)

PG&E and TURN submitted a joint workshop proposal to adopt the current customer method. They argue that there is systematic and significant under-forecasting in the year-ahead LSE forecasts. Further, they contended that a current-customer year-ahead forecast would ease the burden of a monthly local true up (see Section 4.7.2).

In its post-workshop comments, AReM reiterated its contention that the conditions stated in D.05-10-042 for revisiting the best estimate versus current customer issue have not been realized. In particular, AReM submits that there is no liquid capacity market in place, either bilateral or centralized. Moreover, according to AReM, LSEs currently have no reasonable and cost-effective means to adjust their local RA portfolios after the year-ahead RA compliance filing is submitted. AReM believes that as the Standard Capacity Product (SCP; see Section 4.8) is adopted and a more liquid capacity market structure is put in place, a review of the forecasting method may be appropriate.

SCE's filed comments concur with AReM that the stated conditions for revisiting the year-ahead forecasting method have not been met, and NRG's comments in effect do so. However, SCE goes on to urge that the Commission use its discretion to disregard the conditions if new circumstances warrant doing so. TURN on the other hand contends that the conditions have been met because LSEs and suppliers have developed a bilateral market for the exchange of RA capacity, and even the smaller LSEs have been able to fulfill their RA obligations on a consistent basis. Apparently agreeing in part with AReM regarding the importance of the SCP, TURN notes that the CAISO has proposed to implement the SCP for the 2010 compliance year, which TURN believes will greatly facilitate the trading of RA capacity. Finally, TURN its reiterates concern about the under-forecasting issue. TURN notes an estimate by the CEC that the gap between LSEs' forecasts and actual load has been in the range of 500 MW.

Discussion

We find that the conditions specified in D.05-10-042 for reviewing whether to replace the best estimate with the current customer method have not been met. It is true that the Commission did not specify that the capacity market would need to be "centralized," but the context of the passage in D.05-10-042 where the Commission described the conditions makes it apparent that the Commission believed that something more conducive to trading than the current bilateral market environment would be needed.

However, we do not wish to overemphasize the "letter of the law" with respect to the preconditions that D.05-10-042 established for replacing the best estimate with the current customer method. As SCE points out, we could exercise discretion to waive the conditions. More important is the underlying principle. The Commission clearly did not want to place LSEs in a position where they could be saddled with excess capacity, or in need of additional capacity, under market conditions where they would not be able to conduct reasonable and appropriate transactions to acquire or dispose of capacity as needed for load migration.

Despite the evolution of the RA program since D.05-10-042 was issued, we are not persuaded that it is time to change the forecast method. The fact that LSEs have been able to meet their year-ahead RA obligations does not provide assurance that, over the course of the compliance year, the market would be sufficiently liquid to accommodate transactions associated with load migration. Most significantly in this regard, the CAISO's SCP tariff proposal has not yet been implemented. Further, as explained in Section 4.8 of this decision, whether the SCP tariff will be implemented in time for the 2010 compliance year is an open question. Given the importance that most parties ascribe to having the SCP in place to facilitate capacity trading, we view the successful implementation of the CAISO's SCP tariff provisions as a necessary condition for adoption of the current customer approach. Accordingly, we decline to change the year-ahead forecast method to a current customer approach for the 2010 compliance year.

To the extent that under-forecasting by some LSEs continues in practice, we are concerned with the potential for cost-shifting from those LSEs that under-forecast to LSEs who more accurately forecast their loads.[6] The current customer method could provide incentives for greater forecasting accuracy by focusing attention on the likely loads of existing customers. In addition, it would facilitate measures to accommodate load migration in connection with the Local RA program component (see Section 4.7.2). However, this focus may be limited to migration between ESPs, and may not apply to utilities. On balance, we do not find that the concerns regarding under-forecasting outweigh concerns about the impact of market illiquidity at this time.

After the market liquidity issue has been satisfactorily mitigated with the implementation of the SCP tariff, along with any RA program refinements that may be necessary to coordinate with the SCP tariff, it will be appropriate to further evaluate whether to convert year-ahead forecasts to the current customer

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[6] Mitigating this concern is the Energy Division's findings that for the 2008 compliance year, monthly load migration adjustments were significantly decreased from previous years and plausibility adjustments contributed more significantly to total adjustments made to LSE forecasts. (2008 Resource Adequacy Report, at 9.) This suggests that to a greater extent than in prior years, the CEC load forecast review process is resolving and correcting under-forecasting before final load forecasts are assigned to the LSEs.

method. Assuming that the SCP tariff has been approved and implemented before the record of the proceeding establishing RA requirements for the 2011 compliance year is closed, the conversion could take place for that year. SCE makes two additional proposals: (1) expected load growth or reduction for current customer load forecasting should be determined on a system-wide basis by the CEC and calculated as a percentage factor (positive or negative as weather, economic, and other relevant conditions warrant) that LSEs must apply to their prior year's peak load forecast, and (2) the detailed rules necessary for implementation of the current customer approach, including, for example, the appropriate date for determining LSEs' current customer counts and the process for determining the annual load growth/reduction percentage factor shall be developed in workshop jointly conducted by the Energy Division and CEC staff in a subsequent proceeding. (SCE reply comments at 3-4.) While we are not inclined to adopt substantive proposals that first appeared in reply comments, we generally concur with the procedural aspects of SCE's recommendation and believe it is necessary to include these elements in our review.

Finally, it is unclear what changes in administrative burdens for Energy Division and CEC staff are implied by this shift in forecast methodology. We need to be sensitive to such impacts, particularly since a substantial portion of the burden will fall upon the CEC. We welcome the advice of the CEC as well as our own staff in future proceedings on this topic so that we can give appropriate consideration to staffing needs.

4.7.2. Local RA and Load Migration

The RA program provides for monthly true-ups of system RA obligations to account for load migration but does not allow such adjustments for local RA obligations. This has certain adverse effects, as described below. In D.07-06-029, the Commission stated that it remained open to considering a mechanism that would true-up local obligations. D.08-06-031 referred this topic to Phase 2 of this proceeding.

Workshop proposals to address the load migration issue were submitted by SES and jointly by PG&E and TURN. SES describes its view of the problem as follows:

> "Under the current Year-Ahead Local RA model, Local RA is procured annually; there is no obligation to procure additional Local RA capacity if, during the course of the compliance year, an LSE acquires load. Nor are there any opportunities to re-sell Local RA capacity if an LSE loses load. As a consequence, there is no 'market' for the value of Local RA capacity after the year-ahead showing. This results in Local RA capacity losing its local premium value, because if Local RA capacity is resold after the Year-Ahead Local RA showing, it will be valued by the market at the system price for RA. For many LSEs this phenomenon imperils their future viability. From the beginning of the RA program, this risk was identified as an issue that needs to be addressed, for it creates huge regulatory-imposed financial risks. Moreover, it gives any LSE new to the State which acquires customers from an existing LSE an unfair cost advantage, at least for the first year of operation. Allowing LSEs to true-up their Local RA obligations, as they currently do for System RA capacity, may help minimize this financial exposure." (Phase 2 proposal of SES at 2.)

In its pre-workshop submittal, SES proposed to permit LSEs to assign local RA capacity obligations to each end-use customer that migrates. The obligation would be based on the ratio of the customer's August peak demand to the LSE's total August peak demand for all the LSE's customers in a local area. That ratio would be multiplied by the LSE's local capacity obligation for the local area to determine each end-use customer's obligation. For at least the first year of the proposal, the customer-specific obligation would be waived for customers with less than 1,000 kilowatts (kW) August peak demand. As customers migrate from one LSE to another, the losing LSE would report the migrating customer account and the accompanying capacity obligation to the Energy Division. The Energy Division would confirm the release of the capacity obligation on the part of the losing LSE and impose the corresponding obligation on the gaining LSE. SES believes that the number of migrating customers would be low, and therefore does not expect that this process would impose an undue administrative burden on the Commission. SES proposed that the current $40 per kW-year trigger price for local RA capacity remain in effect, and that the utilities be directed to make excess local RA capacity available for purchase. Finally, SES proposed to implement this process on a pilot basis for 2010, assuming that the SCP is implemented during 2009 in time for its use in 2010 procurement.

Responding to concerns raised in the workshop discussions, SES revised its proposal in several respects.[7] First, SES proposes that the assignment of local capacity obligations be limited solely to customers with demand meters. Second, in response to questions about how to manage potential disputes between LSEs about a migrating customer's peak load, SES proposes that each LSE show in its year-ahead local RA compliance submittal the customer-specific August peak load and associated local RA obligation for the lagging year (i.e., August 2009 peak for the 2010 compliance showing submitted in October 2009). Third, utilities would be encouraged rather than directed to offer excess local capacity.

PG&E and TURN submitted a pre-workshop proposal to keep the current year-ahead compliance process and allow trading of the obligation for

[7] Excerpts from the revised SES proposal, which was appended to the Energy Division workshop report, are reproduced in Appendix A to this decision.

month-ahead demonstrations based on a migrating customer's August usage. This proposal was made in connection with the PG&E/TURN proposal to convert to the current customer method for determining year-ahead procurement obligations. Like SES's revised proposal, the PG&E/TURN proposal does not require the utilities to offer the sale of excess capacity. In its post-workshop comments, PG&E proposed to require month-ahead compliance filings for local RA, similar to system RA monthly filings.

Some workshop participants raised the possibility of unbundling the "local attribute" from an RA contract, so that only the local attribute would be traded from month to month due to load migration. Energy Division suggested that since local RA obligations are allocated to LSEs based on the share of utility area coincident peak, the customer-specific capacity obligation should likewise be based on the coincident peak.

AReM, PG&E, and TURN support adoption of the revised SES proposal, and DRA and SDG&E state their support for a monthly true-up mechanism. The support is generally conditional, however. AReM believes an additional workshop is needed to explore implementation details. Also, AReM notes that some ESPs are concerned about the risk of taking on an additional procurement obligation before a liquid capacity market is available. AReM's support is contingent upon the implementation of the SCP tariff. DRA believes the true-up mechanism would be facilitated by development of the SCP and by allowing trades between long and short LSEs. PG&E believes that the specific language in the SES proposal that defines the "peak-to-load" ratio requires clarification. PG&E also supports several technical clarifications suggested by TURN at the workshops. SDG&E's support for a true-up mechanism is dependent upon use of the current customer approach to year-ahead forecasts and the institution of the ability to trade the local RA attribute of system RA resources. TURN would modify the SES proposal to base the customer-specific local RA obligation on its forecasted August coincident peak demand for the RA compliance year rather than the recorded peak of the prior year. TURN also believes that the true-up mechanism would function much more smoothly with the current customer approach rather than the best estimate approach.

SCE believes that the proposals for true-ups during the compliance year are inappropriate. Among other things, SCE is concerned that LSEs would have additional procurement requirements imposed on them during the course of the compliance year. SCE believes this would be improper to the extent that the Commission retains the best estimate forecasting method, since that method does not necessarily ensure that all customers are accounted for. SCE is also concerned about having to procure capacity pursuant to a monthly true-up obligation because of the extremely short time frame allowed for such procurement and because there would be an obligation for the gaining LSE to buy but no corresponding obligation for the losing LSE to sell the capacity associated with the migrating customer. Finally, SCE sees the true-up proposals as unnecessary because customer migration is already accounted for in the system RA program, which does allow true-ups for migration. Since a losing LSE can sell excess system RA capacity, the actual financial impact is that the losing LSE bears, for no more than one year, the difference in price between system and local RA capacity acquired to serve the lost customer.

Discussion

Local RA procurement obligations are currently established annually for a 12-month compliance period. Thus, when an LSE loses a customer to another LSE during the compliance period, it temporarily remains saddled with Local

RA procurement costs associated with that customer.[8] At the same time, the LSE that gains the migrating customer has no obligation to procure capacity on behalf of that customer for the remainder of the compliance year. This has the effect of shifting costs to the losing LSE, which runs counter to our policy, and the requirements of Section 380(b)(2), to equitably allocate the cost of generation and prevent cost shifting.[9] Among other things, as SES notes, this could provide an unjustified competitive edge to new LSE entrants. SCE argues that this situation is mitigated by the losing LSE's ability to sell system RA capacity on a month-to-month basis, but that is not a complete solution.

This issue has lingered since the Local RA program began, and finding a solution that fairly and effectively resolves the load migration problem without creating problematic new issues has been elusive. After considerable effort over several RA proceedings, SES has presented a proposed mechanism that goes a long ways towards a full solution. By limiting monthly true-ups to instances of documented load migration from one LSE to another, this approach appears less administratively burdensome for LSEs than the proposed alternative of requiring monthly compliance filings for local RA.

We adopt the core principle of the revised SES proposal as set forth in Appendix A, i.e., limiting local RA adjustments to documented load migration, but go no further at this time. In light of the potential benefits of such a process, as well as the time it has taken to get to this point, it is with considerable

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[8] We recognize the concern that this statement holds true only to the extent that the customer's load was reflected in the year-ahead load forecast that underlies the local capacity procurement obligation for that LSE.

[9] Section references herein are to the Public Utilities Code.

reluctance that we defer implementation of such an approach to the 2011 compliance period. We find we must do so for the following reasons:

- Several parties, notably including SES, emphasize the importance of implementing the SCP tariff in connection with the true-up proposal. We concur. We declined to adopt the current customer method for year-ahead load forecasts for several reasons, including the fact that the SCP tariff has not yet been implemented. We did so to provide greater assurance of a more liquid market environment in light of procurement obligations that could unduly impact LSEs. Similarly, since the SES true-up proposal imposes new procurement obligations that must be met in a limited time frame during the compliance year, it is necessary and appropriate to provide that the SCP must be in place before implementing the true-up process.

- We believe it is necessary to explore whether basing the quantity of load that has migrated on the customer's historic peak load for the previous year would be any more accurate than using the forecast of load for the customer. A known value has attractive qualities, but it is not necessarily the most accurate value. A forecast developed closer to the point that migration occurs may be more accurate.

- We concur with AReM that additional workshops are needed to resolve technical issues. Examples of details remaining to be worked out include clarification of the "peak-to-load" ratio, whether to aggregate local areas for simplicity, and whether to use actual or forecast ratios. We note that TURN offered several technical suggestions and commend them to the attention of the workshop participants. Also, the workshops would be needed to address any proposal for unbundling the local attribute of RA capacity to accommodate migration. In this regard, we concur with SCE that it would be improper to adopt a major concept that was first suggested in workshops and not properly proposed according to established procedures.

- We remain concerned that administrative burden of processing LSE's migration claims on our staff may not be as negligible as SES anticipates. Deferring implementation has the advantage of providing our staff an opportunity to develop appropriate procedures and to make necessary staffing assignments.

The SES proposal provides a strong foundation for development of a load migration mechanism that we intend to adopt for 2011. We provide the following guidance. First, we concur with parties who claim it would be improper to require or encourage utilities that are long on local RA capacity to sell that capacity to other LSEs, but not impose the same provision on other LSEs. One of the guiding principles of the RA program, and a requirement of Section 380(e), is the nondiscriminatory imposition of the same requirements on all LSEs. We see no basis for disparate treatment here. Also, in light of our concern about the potential administrative burden of this mechanism, it may be appropriate, at least for the first year, to limit the tracking of migrating customers to those customers with peak demands of, for example, 3 MW.

In comments on the proposed decision, SCE reiterated its opposition to a monthly true-up mechanism for local procurement obligations to account for load migration, and it proposed several issues that it believes must be resolved prior to implementation of such a mechanism. Since we are providing for further proceedings on this issue, SCE may introduce its position on unresolved issues in those proceedings. We do not find it necessary to further specify the scope of those proceedings at this time. We also note, as SES observes, that SCE's concerns about market power may be addressed, in whole or in part, by the market power mitigation measures adopted in D.06-06-064.

4.8. Standard Capacity Product (SCP)

At the request of stakeholders over an extended period, and with the encouragement of this Commission in prior orders, the CAISO staff has developed a draft SCP with availability requirements and incentives for RA resources that would enable more efficient transactions of RA capacity. The CAISO distributed a draft SCP document for discussion in the Phase 2 workshops. CAISO staff indicated that it intended to seek approval of its Board of Governors in February 2009 and file an SCP tariff at the Federal Energy Regulatory Commission (FERC) in March 2009. In its opening comments, the CAISO indicated it planned to file the SCP tariff with the FERC in April 2009. At the time of the workshops, CAISO staff was still developing provisions of the SCP proposal dealing with contract grandfathering, unit substitution, and clarifications to the proposal.

The CAISO staff summarized the draft SCP proposal as follows:

- "Availability Standard. If a resource receives payments for providing RA capacity, there is an expectation that the full RA capacity of that resource will be available to the CAISO, i.e., the resource is not on a forced equipment outage or derate that diminishes its ability to provide the full amount of its RA capacity. Under the SCP, hourly resource availability will be tracked on a monthly basis and compared against a single availability standard or target based on the historic performance of the RA resource fleet during the peak hours of each month of the previous year."

- "Availability Incentives. The SCP proposal will provide incentives for each resource to meet or exceed the target availability standard. On a monthly basis the CAISO will assess financial penalties to resources whose availability falls short of the target, and will provide bonus payments to resources whose availability exceeds the target. Bonus payments will be funded only through available financial penalty revenues. This will ensure that the mechanism is revenue neutral on a monthly basis and does not depend on revenues from other sources."

- "Unit Substitution. A resource owner will be able to substitute a non-RA resource for an RA resource on forced outage in order to avoid the outage being counted against the RA resource's availability. A pre-approval process will be required to ensure that the replacement capacity is comparable to the original RA capacity in an operational sense."

- "Transition to SCP. The SCP has provisions for the grandfathering of existing RA contracts that have availability standards and incentives comparable to those specified in the SCP tariff language. Such grandfathered contracts would be exempt from the CAISO-enforced availability standards and incentives under the SCP. Upon the expiration of such contracts, any grandfathering would cease."

- "Deferment of SCP availability standards and incentives for certain RA resource types. The CAISO proposal would not initially apply the SCP availability provisions to intermittent renewable generation (wind and solar), [QFs], and demand response resources. The CAISO intends to revisit the applicability of the SCP provisions to these resource types at a later date."

Since FERC approval of the SCP tariff was not obtained sufficiently in advance of the close of the Phase 2 record, parties have not had an opportunity to comment on the final SCP provisions and whether and how this Commission's RA program might need to be modified in light of them. At this time, we are hopeful that such FERC approval and opportunity for comment can be realized so that, if found to be appropriate, the SCP can be fully integrated into our RA program for the 2010 compliance year. Accordingly, we will leave this proceeding open for a limited time, and for the limited purpose of addressing SCP implementation issues that include whether and to what extent the final SCP should be required for RA compliance and whether the existing replacement requirement of the scheduled outage counting protocol should be eliminated if the SCP is implemented. We clarify that while we defer action on mandating the SCP for RA compliance, contracts that include the final SCP provisions will be eligible to count for RA compliance in 2010.

We also adopt SCE's proposal to maintain a three-month interval between a Commission decision on SCP issues and the date for LSE compliance showings. As SCE observes, it would be poor policy to require parties to assume the outcome of the SCP process and, in effect, begin implementing a program still being conceptualized. Thus, for example, if FERC approval of the SCP tariff occurs in May 2009 and it is then possible to conduct an expedited comment process that concludes by mid-June 2009, then it might be possible for the Commission to act on SCP issues at its scheduled July 30, 2009 meeting. In the event it is not possible to conclude the process with a final decision by July 30, 2009, then the SCP implementation issues would be addressed in a future RA proceeding, and the SCP would be fully implemented with the 2011 compliance year.

4.9. Ancillary Services (AS) Must Offer Obligation (MOO)

Under the CAISO's Market Redesign and Technology Upgrade (MRTU) tariff, RA resources (except units in an outage and certain ULRs) have an obligation to submit in the Integrated Forward Market (IFM) either self-schedules or economic bids for all their RA capacity. This obligation is referred to as the RA MOO. The CAISO staff presented a workshop proposal explaining its plan to file a proposed tariff with the FERC to add an AS MOO to the existing RA MOO. Although related to the draft SCP tariff, it is a separable proposal. Under CAISO's AS MOO proposal, generators who are certified to provide AS must bid the AS capacity into the CAISO's IFM in addition to making an energy bid. CAISO states that the AS MOO is needed so that the MRTU markets can "co-optimize" energy and AS bids and to prevent withholding of AS capacity. CAISO staff clarified that they do not intend this proposal to change the way that LSEs contract for RA. In particular, CAISO is not proposing that there be a requirement that LSEs, either individually or collectively, procure a certain amount of AS certified resources for RA. The CAISO seeks a statement of support for its AS MOO proposal.

DRA, SCE and TURN support the CAISO's proposed AS MOO. PG&E supports it as long as the exemption for ULRs such as hydro is maintained. NRG is concerned about the equity of the AS MOO because it exempts self-scheduled hydro resources that are otherwise certified to provide AS.

Discussion

The CAISO states the approval of the AS MOO tariff will not impose any additional burdens or costs on LSEs. By requiring suppliers to bid into the AS market, the CAISO will be able to better optimize the resources its selects, which should result in lower costs for ratepayers. We therefore generally support this proposal. However, we note that the record was not adequately developed to enable us to weigh the substantive merits of NRG's or PG&E's concerns regarding the exemption of certain hydro resources from the AS MOO. We further note that the record does not enable us to weigh the concern of the Independent Energy Producers Association that the proposed tariff could create uninterested incentives and decrease the overall supply of ancillary services.

4.10. Qualifying Capacity (QC) for Intermittent Resources

4.10.1. Background

Qualifying Capacity (QC) represents the gross amount of a resource's capacity, prior to an adjustment for deliverability, that can be counted for meeting the Commission's RA procurement obligation. Net qualifying capacity (NQC) is the amount of a resource's capacity that can actually be counted for RA compliance filings. For intermittent resources, including wind, solar, biomass, and as-available cogeneration, QC values are calculated for each month of the year based on averages of historic production performance data.

In recent years, concerns have arisen that the averaging method may not be appropriate for determining the NQC of wind and solar resources. In its 2007 Resource Adequacy Report (April 15, 2008), the Energy Division provided data showing that the current method overstates the available capacity of wind resources during peak demand periods. Energy Division observed that:

> "…[D]aily production deviates broadly, in both directions, from the established NQC." (2007 Resource Adequacy Report, at 20.)
>
> "Wind production is extremely variable." (*Id.*)
>
> "…[W]ind production is negatively correlated with CAISO system load and prices in both zones (North of Path 15 (NP 15) and South of Path 15 (SP 15)) during the summer months, indicating that wind production is generally lower during the periods of high prices and high demand. (*Id.* at 23-24.)
>
> "Wind production at super-peak hours very often falls below NQC. Figure 8 shows that in only one of the twenty hours of highest load during the summer of 2007 did the actual hourly wind production [exceed] NQC." (*Id.* at 24.)

In view of such concerns, a review of the counting rule for intermittent resources was taken up in Phase 1, where the issue was referred to Phase 2. While much of the focus has been on existing wind resources, we also consider the intermittent resource counting rule as it applies to solar resources. As the Energy Division notes, many large new solar resources are expected in California in the next several years, and the counting rules for new solar units warrant discussion.

4.10.2. Proposals

Workshop proposals regarding the counting rule for intermittent resources were submitted by CAISO, SCE, and SDG&E (Joint Proponents; see Appendix B); CalWEA and AWEA; DRA; Dynegy; LSA; and PG&E. Along with these parties, NRG, SA, Sempra Generation, and TURN addressed this issue in their post-workshop comments.

As the staff workshop report explains, the proposals for counting the QC of intermittent resources can generally be grouped into three categories:

> **Historical Average (current method):** Either a straight or weighted average of historical data typically from a specific set of "important" hours. CalWEA and AWEA proposed to continue this approach. LSA also proposed to maintain the current counting method but suggested another approach for intermittent resources, described below. PG&E proposed averaging the production of intermittent generation during the top ten load hours from each month.
>
> **Historical Exceedance:** Usually in a set of important hours, this method uses a percentile to estimate how much generation is available for some percent of the time. For example, what quantity of generation was exceeded during 80% of the important hours? Exceedance approaches recognize an important diversity effect; an exceedance of multiple, different resources will generally have a higher exceedance than the sum of the exceedances of the individual resources.

Dynegy presented an exceedance approach with an exceedance factor of one minus the forced outage rate of thermal RA generators. Joint Proponents presented an exceedance proposal for both wind and solar resources that uses three years of data, all days of the month, and five important hours per day. Wind units would receive a "diversity benefit" based on the difference between the exceedance value of a wind area and the sum of the exceedance value of the resources in that wind area. The diversity benefit would be allocated proportionally to the individual exceedances. New units would use proxy data based on the wind area for wind units or Transmission Access Charge (TAC) area for solar resources. Energy Division suggested a variation of the exceedance method intended to capture the benefits of geographic diversity. This proposal would apply to three different classes of intermittent resources: wind, solar, and intermittent cogeneration. An exceedance value would be calculated for each class, statewide. Then the total class exceedance would be allocated to individual units based on energy production.

Effective Load Carrying Capacity (ELCC): A statistical calculation of the amount of "reference" capacity needed to improve reliability by the same amount as the intermittent resource. Reference capacity is often a thermal resource with a zero forced outage rate. An ELCC calculation requires an hourly risk metric such as Loss of Load Probability (LOLP) for the historical hours used in the analysis. ELCC studies are generally performed for all hours of the day at once; no set of "important" hours is defined or used. However, the production of the intermittent resource is most important to the calculated ELCC at high risk hours. CalWEA and AWEA believe that the ELCC approach has yielded results that are consistent with continued use of the averaging method. DRA proposed an ELCC approach based on a technique known as the "Garver Approximation."

LSA took a different approach. Rather than changing the QC counting rule, LSA proposes to use the MCC buckets, revised as needed due to changing grid realities, for recognizing both the capacity value and the limitations of intermittent resources. Sempra Generation proposes that the counting rule be considered in conjunction with our current review of the planning reserve margin (R.08-04-012).

4.10.3. Discussion

In its Phase 2 workshop report, Energy Division observed that parties have proposed inconsistent objectives for the RA program. According to the Energy Division, some parties argued that QC rules should measure the performance of a unit at and near the time of system peak load, while others argued that the CAISO needs assurance that RA resources are available at all times. This "all hours" versus "peak hours" dichotomy turns out to be the key issue in determining and resolving the appropriate treatment of intermittent resources in the RA program.

Referring to statements in D.04-01-050 and D.04-10-035, CalWEA and AWEA contend that the Commission has determined that the RA program is not focused solely on the peak hours:

> "The purpose of the RA program is to provide 'reliable service at least cost.' [Footnote reference to D.04-01-050.] The focus of the program is enhancing system reliability. Some parties may assert that the purpose of the RA program is the narrower goal of serving demand during the monthly system peak hour. Although providing capacity during the system peak hour is one aspect of reliability, it does not fully measure a resource's contribution to reliability – indeed, it is a simplified measure, because an electric grid is at a significant risk of failing to meet load in many hours, not just in the peak hour. Indeed, in D.04-10-035, which implemented the RA program, the Commission clarified that the intent of the RA obligation is not limited to serving the single peak hour, but rather the set of hours whose demands are within 10% of the monthly peak. [Footnote reference to D.04-10-035.]" (CalWEA/AWEA proposal, at 2.)

We concur with the proposition that peak system load conditions are not the sole concern of the RA program. We have often acknowledged the importance of maintaining reliability at all times. For example, as we noted earlier in this decision, our MCC bucket approach for determining how to count ULRs provides greater reliability in off-peak periods. The fact remains, however, that providing assurance of dependable resource availability to the CAISO at peak demand periods is and should be the primary focus of the RA program, not just another aspect of it.

After the decisions cited by CalWEA and AWEA were issued, the legislature enacted Section 380, the resource adequacy statute that now constitutes the blueprint for the program.[10] Section 380 (c) provides that:

> (c) Each load-serving entity shall maintain physical generating capacity adequate to meet its load requirements, including, but not limited to, *peak demand* and planning and operating reserves. The generating capacity shall be deliverable to locations and at times as may be necessary to provide reliable electric service. (Emphasis added.)

If there were any doubt prior to the enactment of Section 380, the statute now makes clear that the adequacy of physical generation capacity to meet peak demand plus reserves is a key objective for the RA program. We also note that several aspects of the broader RA program as administered by this Commission, the CAISO, and the CEC are designed based on peak demand hours and are consistent with a primary focus on meeting the peak demand. These include local RA studies, deliverability, import capacity, load forecasts, transmission

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[10] Section 380, enacted by Assembly Bill 380 (Stats. 2005, Chapter 367), became effective January 1, 2006.

system availability, CAM allocations, DR allocations, Path 26 allocations, and import allocations.

By and large, there is little dispute regarding the contention that the current counting rule overstates the availability of wind resources during peak periods.[11] Similarly, parties have not contested the findings that there is a negative correlation between wind production and loads on the CAISO controlled grid, and that wind production is extremely variable and difficult to predict in advance of the hour of interest. Instead, proponents of maintaining the status quo emphasize the need to assure reliability during off-peak periods, in effect acknowledging that intermittent QC as now measured might not be dependable during peak hours. For example, in their January 15, 2009 workshop proposal, CalWEA and AWEA state that "[i]mportantly, the ELCC measures the capacity value of a resource across all hours of the year, and does not focus on just a few peak hours." (CalWEA/AWEA proposal at 5.)

We find this emphasis on off-peak hours to be incompatible with the key objective of the RA program to meet peak demand. Given the demonstrated variability in wind production, the current averaging method is inaccurate because it can produce NQC values that overstate, by a significant amount, the actual, dependable capacity available to the CAISO during the conditions in which monthly peaks are experienced. For example, as the Joint Proponents point out (Joint Proposal, Footnote 5, at 11), production by wind resources in the San Gorgonio wind region for 2005, 2006, and 2007 was 4.9%, 2.4%, and 40.4% of nameplate capacity, respectively. The three-year average is 15.9%, which far

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[11] CEC staff, *California Wind Generation on Hot Summer Days*, presented at the Phase 1 workshop on March 25, 2008.

exceeds the actual output for two of the three years. Such a discrepancy between calculated QC and actual availability demands a correction in how the calculation is made.

Some proponents of continuing the current averaging method argue that the proposed exceedance method could lead to higher procurement costs due to the need to replace the devalued intermittent capacity. While replacement procurement would be required to offset devaluation that results from a more accurate measure of peak availability, that does not constitute a valid argument for continuing a method that overstates the QC of a resource. The goal of resource adequacy is achieve reliability at least cost, not simply to achieve least cost. To the extent we design resource adequacy requirements that fail to provide the resources needed by the CAISO, the CAISO could find it necessary to activate its backstop procurement mechanisms such as the Residual Unit Commitment process, the Exceptional Dispatch process, or the Interim Capacity Procurement Mechanism. The costs of such backstop procurement would ultimately be passed on to ratepayers, offsetting savings that would be realized from a more liberal QC counting rule.

We find that subject to certain clarifications and modifications noted below, the Joint Proposal of the CAISO, SCE, and SDGE best meets our objectives for RA.[12] It calculates QC of intermittent resources that the CAISO can reasonably rely on to serve peak load, thereby meeting the RA program's reliability objective, and it will best mitigate backstop procurement. In addition, it addresses solar as well as wind resources. Moreover, apart from the proposals

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12 Excerpts from the Joint Proponents' comments describing the Joint Proposal are copied in Appendix B.

to continue the current averaging method, it is the only comprehensive proposal that is ready for implementation with the 2010 compliance period. We believe implementation of a more accurate counting convention for intermittent wind and solar resources is important for reliability as soon as practicable, and the Joint Proposal provides a means of achieving such implementation.

Accordingly, we will adopt the Joint Proposal with the following clarifications and modifications. First, we note that Joint Proponents suggest that the exceedance level could be set between 70% and 80%, and propose initially setting it at 70%. We adopt a 70% exceedance level and specify that any change would be considered in a future RA proceeding. Second, we adopt the CalWEA/AWEA/SA proposal to aggregate the diversity benefits of solar and wind generation to recognize the complementary profiles of these resources. Conceptually, this is not unlike the Joint Proposal's provision for aggregating wind resources within a defined wind area, and it gives appropriate recognition to the growing importance of both wind and solar generation in California. Finally, we are persuaded that it would be reasonable to recognize and incorporate into the exceedance method the locational diversity benefit of aggregating intermittent resource on a statewide basis. Although the CAISO expressed concern that transmission constraints may limit the practical benefits of geographic diversity because, for instance, Northern California wind resources may not be deliverable to Southern California during a peak event, we are not persuaded that systematic congestion during peak loads prevents intermittent resources from being deliverable. To the extent that the CAISO has concerns about deliverability due to congestion on Path 26, such concerns should be revised in the next RA update process. The adopted rule is set forth in Appendix C.[13] Finally, we note our concern that data on nameplate capacity for existing units may contain errors. While we adopt the use of nameplate capacity as described in the Joint Proposal for 2010, we direct Energy Division to investigate the issue and propose a solution, if appropriate, in the successor to this proceeding.

5. Disposition of Proceeding

This decision concludes consideration of all Phase 2 issues except for the CAISO's SCP tariff and coordination of the RA program with the final, adopted SCP provisions. As determined in Section 4.8, we will leave this proceeding open for a limited time to accommodate the possibility that the FERC will approve an SCP tariff, and we can institute a comment process and issue a final decision on SCP issues not later than July 30, 2009. We intend to institute a successor rulemaking proceeding later this year both to oversee the RA program and to establish local procurement obligations for 2011 and possibly in future years. We will therefore order the closure of this proceeding on July 30, 2009. In the event it is not possible to resolve SCP issues by July 30, 2009, the record of this proceeding with respect to those issues shall be incorporated in the record of the successor rulemaking proceeding.

In D.08-06-031, we authorized the assigned Commissioner or assigned ALJ to extend any compliance dates set forth in that decision. Since we will be closing this proceeding, we will not provide similar authorization in this

[13] To clarify the adopted exceedance methodology, we have made minor changes to the wording of Appendix C as it appeared in the proposed decision. It clarifies that the diversity benefit is allocated based on energy production.

decision. Accordingly, any requests for extensions of time to comply with this decision should be submitted to the Executive Director pursuant to Rule 16.6 of the Commission's Rules of Practice and Procedure.

6. 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 comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed by CAISO, CalWEA, AWEA, SA, and LSA; Center for Energy Efficiency and Renewable Technologies; DRA, Dynegy; Independent Energy Producers Association, PG&E, SCE, SDG&E, and TURN, and reply comments were filed by CAISO; CalWEA, AWEA, SA, and LSA, DRA, PG&E, SCE, SDG&E, SES, and TURN. To the extent that the comments and replies merely reargued positions previously taken, or attempted to introduce new proposals not previously identified in the record, such comments and replies are accorded no weight.

7. 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. The assumptions, processes, and criteria used for the 2010 LCR study were discussed and recommended in a CAISO stakeholder meeting, and they generally mirror those used in the 2007, 2008, and 2009 LCR studies.

2. The Option 1 (Category B) reliability level presented in the 2010 LCR study report 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 (Category C) is the local capacity level that the CAISO needs to reliably operate the grid per NERC, WECC, and CAISO standards.

3. Allowing new capacity that will become commercially operational during an RA compliance period to be counted in an LSE's compliance showing for that period could avoid unnecessarily driving up costs.

4. The portion of the interim rule adopted by D.08-06-031 for counting new capacity that provides that an LSE must claim the entire new resource and show a single local substitute unit could undermine efficient trading of local resources and reduce the options available to the LSE for fulfilling its compliance obligation.

5. Switching to monthly reallocations of CAM credits when an individual service territory has two or more operational CAM contracts, and reallocating CAM credits only when there is a change greater than 0.5 MW for any LSE, appropriately balance the need for fairly allocating CAM credits and avoiding additional administrative burdens on the Energy Division.

6. The MCC bucket approach is both a reliability measure and a cost-saving measure, and elimination of the approach without a viable replacement mechanism could increase reliability concerns and raise procurement costs.

7. The LI protocols adopted by D.08-04-050 would provide a defined, uniform standard for evaluating DR programs for RA purposes.

8. Improved consistency and accuracy in the calculation of DR load impact estimates would benefit the RA program by giving appropriate weight to the capacity value of these resources.

9. Greater transparency in the DR capacity credit allocation process would promote fairness and confidence in the RA program.

10. Since bundled service ratepayers provide funding for the benefits of certain DR programs, they effectively procure DR capacity associated with those programs.

11. The proposed "Historical Output Correction" methodology for resources whose NQC is based on a rolling average avoids double counting of schedule outages that could lead to unnecessary procurement.

12. Successful implementation of the CAISO's SCP tariff provisions is expected to facilitate capacity trading.

13. Under-forecasting by an LSE has the potential to cause cost-shifting from that LSE to LSEs that more accurately forecast their loads.

14. Requiring year-ahead load forecasts without allowing for monthly true-ups based on customer load migrations could contravene our policy to equitably allocate the cost of generation and prevent cost shifting.

15. Providing assurance of dependable physical generation resource availability to the CAISO at peak demand periods is the primary focus of the RA program.

16. The current QC counting rule for intermittent resources overstates the availability of wind resources during peak periods, and there is a negative correlation between wind production and loads on the CAISO controlled grid.

Conclusions of Law

1. The CAISO's 2010 LCR study should be approved as the basis for establishing local procurement obligations for 2010 applicable to Commission-jurisdictional LSEs.

2. Application of the Option 2/Category C local area reliability standard should be continued for setting local procurement obligations for 2010.

3. 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.

4. The RA program should be modified with respect to (a) new resources whose anticipated commercial operation date is after the date for annual compliance filings, (b) CAM allocations, (c) LI protocols for DR resources, (d) transparency in the DR capacity credit allocation process, (e) scheduled outages for resources whose NQC is calculated using a rolling average, and (f) the Joint Proposal for counting the QC of intermittent wind and solar resources should be adopted with a 70% exceedance factor and with modifications to aggregate the diversity benefits of wind and solar resources and to incorporate the locational diversity benefit of aggregating intermittent resource on a statewide basis.

5. The MCC bucket approach for counting use-limited resources adopted by D.05-10-042 should be continued in effect.

6. The Energy Division should convene an educational workshop and/or publish guidelines to describe and explain the LI protocols used to calculate the capacity of demand response programs.

7. It would be inequitable to bundled service customers to allocate and assign DR capacity credits to LSEs on the basis of which customers participate in the DR program.

8. Whether year-ahead load forecasts should be based on the current customer method should be reviewed in future RA proceedings.

9. The revised SES proposal for monthly true-ups of local procurement obligations, set forth in Appendix A, should be considered in a future RA

proceeding subject to the qualifications and modifications stated in the foregoing discussion.

10. This proceeding should remain open for a limited time to provide opportunity for comment on SCP issues, and should be closed on July 30, 2009.

O R D E R

IT IS ORDERED that:

1. The local resource adequacy program and associated requirements adopted in Decision (D.) 06-06-064 for compliance year 2007, and continued in effect by D.07-06-029 and D.08-06-031 for compliance years 2008 and 2009, respectively, are continued in effect for compliance year 2010, subject to the modifications, refinements, and Local Capacity Requirements adopted by this decision, as set forth in the ordering paragraphs below.

2. The "Option 2/Category C" Local Capacity Requirements set forth in the California Independent System Operator's *2010 Local Capacity Technical Analysis, Final Report and Study Results*, dated May 1, 2009, are adopted as the basis for establishing local resource adequacy procurement obligations for load-serving entities subject to this Commission's resource adequacy program requirements.

3. The following modifications to the resource adequacy requirements adopted by D.04-01-050; D.04-10-035; D.05-10-042 as modified by D.06-02-007, D.06-04-040, and D.06-12-037; D.06-06-064, D.06-07-031; D.07-06-029; and D.08-06-031 are adopted beginning with the 2010 resource adequacy program compliance year:

   a. A load-serving entity may count toward its local resource adequacy obligation all or a portion of a new generation unit that has not reached commercial operation as of the due date for submission of its year-ahead local compliance showing, provided that the load-serving entity must show a unit or units in the same local area that it will continue to list on every monthly filing to make up its local capacity obligation until the new unit has reached commercial operation.

b. For service territories with one operational Cost Allocation Methodology contract, Energy Division shall perform quarterly reallocations of Cost Allocation Methodology credits. For service territories with two or more operational Cost Allocation Methodology contracts, Energy Division shall perform monthly reallocations of Cost Allocation Methodology credits. If, for any month, a reallocation would result in no change greater than 0.5 megawatts for any load-serving entity, Cost Allocation Methodology credits would not be reallocated that month.

c. For purposes of the resource adequacy program, calculation of the capacity of demand response programs should, to the maximum extent possible, reflect the load impact protocols adopted by Decision 08-04-050.

d. In allocating and assigning demand response program capacity credits to individual load-serving entities, Energy Division should (1) provide each load-serving entity with an explicit accounting of how the megawatts associated with each demand response program were allocated to the load-serving entity, (2) provide each LSE with a preliminary assignment of demand response credits not less than 10 days prior to the final assignment, (3) publish the total qualifying capacity of demand response programs on a program-specific basis, and (4) publish information about the process and criteria used to administer the demand response credit allocation process as well as any actual data that do not inappropriately disclose market-sensitive information.

e. When the net qualifying capacity of a resource is calculated using a rolling average, scheduled outages shall be accounted for using the "Historical Output Correction" jointly proposed in workshops in Phase 2 of Rulemaking 08-01-025 by the California

Independent System Operator, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company. The California Independent System Operator will provide data on historical outages subject to the scheduled outage counting criterion to the California Energy Commission. The California Energy Commission will substitute proxy data for the hours of the scheduled outage. This proxy data will be calculated by averaging the same hours for the other two years of data used in the overall qualifying capacity calculation.

f. The rules for counting the qualifying capacity of intermittent wind and solar resources set forth in Appendix C to this decision are adopted.

4. The April 14, 2009 motion of Southern California Edison Company, Pacific Gas and Electric Company, and the Utility Reform Network to supplement the record with the Energy Division's 2008 Resource Adequacy Report is granted.

5. Rulemaking 08-01-025 shall be closed on July 30, 2009.

This order is effective today.

Dated June 18, 2009, at San Francisco, California.

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

APPENDIX A

Excerpts from the Revised Monthly Local Capacity Proposal of Sempra Energy Solutions, LLC (SES)[1]

[T]he California Public Utilities Commission ("Commission") should permit [load-serving entities (LSEs)] to calculate, using a standard methodology, Local [resource adequacy (RA)] capacity obligations for end-use customers that migrate. Annually, LSEs would assign a Local RA capacity obligation to each and every end-use customer in their service portfolio.

A simple assignment methodology would be based on the end-use customer's previous year's August peak demand (2009 for the 2010 compliance year) at the time of the [California Independent System Operator's (CAISO)] August system peak, by service account, divided by the LSE's total 2009 August peak demand for all of the LSE's customers at the local area's August system peak time in that local area. This number is the customer's peak-to-load ratio, by local area aggregated by [utility distributed company (UDC)], and would be a number less than 1.00. The sum of all of an LSE's customer's peak-to-load ratios should add to approximately 1.00 for each local [investor-owned utility (IOU)] service area. Each customer's peak-to-load ratio would then be multiplied by the LSE's [California Energy Commission (CEC)]-assigned Local RA capacity obligation for 2010 (assuming a 2010 compliance year) for that customer's local IOU service area. The result of this exercise would be the end-use customer's [local procurement obligation (LPO)] based on the CEC-assigned Local RA capacity obligation for the compliance year. For simplicity's sake, or until stakeholders determine otherwise, local RA areas are aggregated by IOU service areas, and tracking and transferring monthly [LPO] is waived if, for that month, all service accounts migrating within an IOU's service area aggregate to 0.99 MW of [LPO] or less, by LSE to LSE.

For the first year of the program, or until stakeholders determine otherwise, only accounts that are demand metered will be eligible for [LPO] migration.

As end-use customers migrate during the year from one LSE to another, the losing LSE would identify the account(s) and the associated [LPO] in a tabbed

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[1] These excerpts are copied from Appendix 2 of the February 6, 2009 Energy Division Workshop Report.

sheet on the monthly RA forecast submitted to the CEC and the Energy Division of the Commission. The forecast is submitted approximately 60 days prior to the monthly RA showing. The migrating customer(s) would also be identified on the gaining LSE's monthly forecast and tabbed sheet. The Energy Division would match this migration and confirm the release of Local RA capacity obligation from the losing LSE and impose an additional Local RA capacity obligation on the gaining LSE. At the time of the monthly RA resource showing, which is approximately 30 days following the forecast, the gaining LSE would identify the additional Local RA capacity used to meet the incoming load.

If there is a dispute between LSEs as it pertains to the migration obligation, it will be the responsibility of the LSE losing the obligation to document the capacity calculations and submit to the Energy Division. Since the only component of the calculation that is potentially debatable is an account's August peak load, at the time of the 2010 Year-Ahead [LPO] showing, due in October of 2009, each LSE is shall make the account specific obligation calculations and submit the results to the Energy Division. This list should maintain customer confidentiality, yet document each [direct access (DA)]-eligible service account's 2008 August peak demand and their [LPO] for 2010, rounded to the hundredths place. An LSE that elects not to submit the list of account [LPO] will not be allowed to request a transfer of LAR Obligation as their load migrates to another LSE. However, that same LSE will still be required to assume a [LPO] from an LSE that has submitted the list if that obligation transfer is approved by the Energy Division.

To address the concerns of asymmetry, the $40.00 per kilowatt per year trigger price for Local RA capacity would remain in effect, and the three UDCs, which control the majority of Local RA capacity, should endeavor to make any excess Local RA capacity available for purchase via a monthly request for offer process or similar non-discriminatory access – as the sale of Local RA capacity reduces the costs of utility procurement for bundled customers.

This proposal is intended as a pilot for the 2010 compliance period assuming that a Standard Tradable Capacity product will likely be implemented during 2009 or sometime 2010 by the CAISO. Any extensions, changes or modifications to the process outlined herein can be proposed during the appropriate proceeding in early 2010 defining the parameters of the 2011 RA program and after parties have gained some experience with this Local RA true-up mechanism during the 2010 program year.

(END OF APPENDIX A)

APPENDIX B

Excerpts from the Joint Proposal of the California Independent System Operator, Southern California Edison Company, and San Diego Gas & Electric Company Regarding Calculation of Quality Capacity for Wind and Solar Resources[1]

1. Proposed Methodology for Counting Wind and Solar Resources with Three or More Years Operating Data

Set forth below is the specific intermittent resource counting methodology reflected in the Joint Proposal, including the steps in the calculation and the data that must be obtained to implement the methodology.

Performing the analysis requires the following load and generation data:

1. The previous three years of wind generation energy production data (hourly integrated) for each wind resource for each of the six wind areas within California.[2] Each wind resource will be assigned to one of the six wind areas within California.[3]
2. For each wind area and for each wind resource within that wind area, the hourly integrated generation that corresponds to the five peak hours of each day of the month. A set of about 450 data points (5 peak hours * 30 days per month * 3 years of data) will be collected for each wind area and each wind resource within that wind area. The hours for each month shall be:

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[1] These excerpts are copied from the opening comments of CAISO, pp. 14-21.

[2] The CAISO, SCE and SDG&E have proposed that the CPUC establish the following six wind areas within California for purposes of this proposal:

- San Gorgonio;
- Tehachapi;
- Altamont;
- Solano;
- Pacheco Pass; and
- San Diego.

[3] The wind areas may change over time to the extent wind resources are constructed in areas other than those previously defined.

Jan–Mar, Nov and Dec	HE17-HE21 (4:00 p.m.-9:00 p.m.)
Apr–Oct	HE14-HE18 (1:00 p.m.-6:00 p.m.)

The Joint Proposal is based on establishing an appropriate level of confidence that intermittent RA resources will be generating at (or above) their RA capacity value during the peak demand period through the use of an exceedance methodology. The Joint Proposal also captures the diversity benefit of aggregating multiple intermittent resources in a wind resource area. The diversity benefit is a result of higher output from some wind resources offsetting lower output of other resources in the same wind area. As a result, the QC value for the wind area will generally equal or exceed the sum of the individual wind resource QCs at a given exceedance level. The initial proposal served on January 15, 2009 provided a means to allocate this diversity benefit across individual resources within a wind area. Following the initial filing, the CAISO, SCE and SDG&E worked with the California Energy Commission ("CEC") to refine the calculation procedure to fairly allocate diversity benefits. This procedure is as follows:

Using the data identified above, the following would be determined for each resource and the six wind areas within California:

1. Calculate the exceedance (70-80% as appropriate) QC for each resource in the wind area for each of the three years of the data period. These are referred to as the **initial QCs** for each resource; Save these values.
2. Calculate the exceedance QC for the entire wind area for each year of the data period; these are the **wind area QCs**.
3. Calculate the diversity factor for each wind area for each year of the data period. The diversity factor is the wind area QC divided by the sum of all initial QCs for that month; a value greater than 1 implies a positive diversity benefit. These are the **annual diversity factors** for each wind area. Save these values.
4. Calculate the percentage of nameplate by dividing wind area QC by total nameplate capacity for each year of the data period. These are the **annual wind area % nameplate ratings**. Save these values.
5. Calculate the future NQC for each resource by multiplying each year's **initial QC** (from Step #1) by that year's **annual diversity**

factor (from Step #3); this is the annual calculated QC for each resource.

6. If there are less than three years of data, estimate the resource's NQC for the missing year(s) by multiplying the resource nameplate capacity by the **annual wind area % nameplate rating** (from Step #4); this is the **annual estimated NQC**.
7. For each resource, average the **annual calculated QCs** and **annual estimated QCs** (if any) together. This average is the final QC for each resource that would be used for the following year's RA requirements.
8. QC values are calculated by the CEC and published on the CAISO website.

As a general matter, the Wind Area QC will be greater than the sum of the wind resource QCs within that wind area due to the diversification benefit described in section III.C. The positive delta will be added to each wind resource's Initial QC on a *pro rata* basis. An example of this allocation is provided below:

- For a given exceedance factor, Wind Area A (containing three wind resources) has a Wind Area QC of 75 MW. Each wind resource (at the same exceedance factor) has Initial QCs as follows:

  Wind Resource 1: 30 MW Initial QC

  Wind Resource 2: 20 MW Initial QC

  Wind Resource 3: 10 MW Initial QC

- The positive delta of 15 MW (Wind Area QC minus sum of Wind Resource Initial QCs) is allocated in proportion to each wind resource's Initial QC; 7.5 MW or 50% of the positive delta is added to Wind Resource 1's Initial QC, 5 MW or 33% is added to Wind Resource 2's Initial QC and 2.5 MW or 17% is added to Wind Resource 3's Initial QC.
- The final QC for each wind resource is as follows:

  Wind Resource 1: 37.5 MW final QC

  Wind Resource 2: 25 MW final QC

  Wind Resource 3: 12.5 MW final QC

2. Proposed Revisions To The Methodologies for Counting Wind and Solar Resources with Less than Three Years of Operating Data

a. Wind Resources

The rules for counting wind resources with less than three years of operating history were established under Decision (D.) 07-06-029, June 21, 2007. These rules provide as follows:

> **<u>For new units</u>**: 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, 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%, year 2 was 22%, and year 3 was 24%, the new unit's QC for June would be 23% of its NDC: (23 + 22 + 24) / 3 = 23%.
>
> **<u>For units with some operating experience, but less than two years of data</u>**: 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 three-year formula. For example, if the average wind unit production in the TAC area as a percent of NDC during June of year 1 was 23%, year 2 was 22%, and year 3 was 24%, and the new unit production for June was 21% of NDC for year 3, the unit's QC for June would be 22% of its NDC: (23 + 22 + 21) / 3 = 22%.
>
> **<u>For units with at least two years of operating experience, but lessthan three years of data</u>**: The unit's actual operating experience will be used. In some months, the QC value will be based on two years of data rather than three years of data (as established in the counting convention).

The CAISO, SCE and SDG&E have proposed that the current RA provisions for wind units with less than three years of operating data (copied below in section C.1.a.), be changed as follows:

- o Use a wind production factor calculated on a wind area basis as described in this proposal, instead of using the wind production factor of all wind units within the TAC area; and
- o Determine the production factor using the exceedance approach described above for resources with three years of operating data,

instead of using the average wind production factor of all units within the area where the unit is located.

Specifically, for new wind resources without three years of operating data, the QC value would be determined using "proxy" data derived on a wind area basis for the years for which actual operating data is not available. Thus, until the particular resource has three years of historic production data, the amount of capacity that a new wind resource can be counted for RA purposes would be determined by using the Wind Area QC (the calculation of which is described above in the proposal for how to treat resources with three years of operating data) of the particular wind area in which the resource is located to "fill in" the missing years of data.

The "missing data" for a particular year for a new resource would be derived as follows. Note that a Wind Area QC value will be determined each year by the CEC and CPUC. The nameplate MW of a new resource that does not have three years of operating data would be multiplied by the following factor:

$$\text{Factor} = \frac{\text{Wind Area QC in MW}}{\text{Sum of Nameplate MW of All Wind Resources in Wind Area}}.$$

Example:

Nameplate MW of all RA resources in Wind Area A = 1,000 MW
CEC calculated Wind Area QC MW value = 100 MW
Factor = 100 MW/1000 MW = 10.0%
QC value for this year for a 150 MW new resource is 150 MW x 0.100 =15 MW

b. Solar Resources

The CAISO, SCE and SDG&E have proposed that the exceedance methodology described above for use with wind resources also apply to solar resources with less than three years of operating data. However, the CAISO notes that there are two significantly different categories of technology in the solar resources. First, "photovoltaic" technologies typically receive the solar radiation and directly convert this to electricity. This approach is highly responsive to sunlight and therefore can have rapid and significant fluctuations with broken cloud cover. Second, the thermal solar technologies receive solar radiation to heat an intermediate substance before producing electricity through a thermal conversion such as a steam turbine connected to an electric generator. This technology is able to maintain more stable electric output and is less susceptible to cloud cover changes. Thus, the CAISO supports dividing solar resources into two categories -- "thermal solar" and "photovoltaic" – because they are sufficiently different technologies.

The CAISO has not recommended using the wind area for determining the proxy value to use in the years where there is no actual data, but instead recommend that the proxy be calculated using an exceedance methodology focused on the production of all solar units within each technology category within the TAC area where the solar unit is located. The CAISO proposes that this approach be used as the starting point for a methodology that would be in effect starting in 2010. However, the CAISO recognizes that as more solar resources come on line over the next few years the methodology may need to be revisited. The TAC area is a sufficiently vast geographic area that it will capture a reasonable amount of solar resources to serve as "proxy" resources for the QC determination. At this time, given the limited number of solar resources that have come on line, there is no option comparable to a "wind area" in which like solar resources can be grouped.

(END OF APPENDIX B)

APPENDIX C

Adopted Methodology for Counting Wind and Solar Resources

Set forth below is the specific intermittent resource counting methodology adapted from the Joint Proposal, including the steps in the calculation and the data that must be obtained to implement the methodology.

Performing the analysis requires the following load and generation data to calculate a monthly QC:

1. The previous three years of wind/solar generation energy production data (hourly integrated) for each wind/solar resource within California.
2. For each wind/solar resource, the hourly integrated generation that corresponds to the five peak hours of each day of the month. A set of about 450 data points (5 peak hours * 30 days per month * 3 years of data) will be collected for each wind/solar resource. The included hours for each month shall be:

Jan–Mar, Nov and Dec:	HE17-HE21 (4:00 p.m.-9:00 p.m.)
Apr–Oct:	HE14-HE18 (1:00 p.m.-6:00 p.m.)

The Joint Proposal is based on establishing an appropriate level of confidence that intermittent RA resources will be generating at (or above) their RA capacity value during the peak demand period through the use of an exceedance methodology. The Joint Proposal also captures the diversity benefit of aggregating multiple intermittent resources in California. The diversity benefit is the result of higher output from some wind/solar resources offsetting lower output of other resources. As a result, the wind/solar QC value for California will generally equal or exceed the sum of the individual wind/solar resource QCs at a given exceedance level. The initial proposal served on January 15, 2009 provided a means to allocate this diversity benefit across individual resources within the state. Following the initial filing, the California Independent System Operator Corporation (CAISO), Southern California Edison Company, and San Diego Gas & Electric Company worked with the

California Energy Commission (CEC) to refine the calculation procedure to fairly allocate diversity benefits.

Using the data identified above, the following would be determined for each calendar month of each included year (therefore, steps 1-7 will be repeated 36 times {3 years * 12 months} and step 8 will be repeated twelve times {once for each month}) for each resource individually or for California as a whole:

1. Calculate the exceedance (70%) QC for each resource for each month of each of the three years of the data period. These are referred to as the **initial QCs** for each resource. As described above, a resource with at least three years of operational history will have 36 initial QCs. Save these values.

2. Calculate the exceedance QC for the entire state for each month of each year of the data period; these are the 36 **wind/solar state QCs**.

3. Calculate the **diversity benefit** for each month of each year of the data period. The diversity benefit is the difference between the wind/solar state QC and the sum of all initial QCs for that month these are the **diversity benefits**. Save these 36 values.

4. Calculate the percentage of capacity[1] by dividing wind/solar state QC by total capacity for each month of each year of the data period. For this step, all wind and solar resources are treated together. For each of the 36 included months, only the units with production (MWh) for at least 15 days during the month should have their capacity (MW) included in the denominator. These are the **wind/solar state% capacity ratings**. Save these 36 values.

[1] Nameplate capacity values will be used for 2010 compliance, but due to concerns about the validity of reported nameplate capacity data, another approach (e.g., maximum reported production) may be adopted for 2011.

5. Calculate the 36 **diversity shares** for each resource by dividing the total energy produced during included hours by the resource for each month of each year by the total energy produced by all wind/solar resources during included hours each month of each year.

6. Calculate the future QC for each resource by multiplying the **diversity share** (from Step #5) by the **diversity benefit** (from Step #3); this is the **calculated QC** for each resource. This is done for each month of each year, resulting in 36 **future QCs** for each resource with at least three years of data.

7. For each calendar month, if there are less than three years of data, estimate the resource's QC for the missing year(s) by multiplying the resource capacity by the **wind/solar state% capacity rating** (from Step #4); this is the **estimated QC**.

8. For each resource, average the **calculated QCs** (if any) and **estimated QCs** (if any) together. This average of the three most recent calculated or estimated month specific QCs is the **final QC** for each resource that would be used for the following year's RA requirements. Twelve monthly QC values are calculated for each resource and published on the CAISO website.

As a general matter, the wind/solar state QC will be greater than the sum of the wind/solar resource QCs due to the diversity benefit described in section III.C of the Joint Proposal. The positive delta (diversity benefit) will be added to each wind/solar resource's Initial QC on a *pro rata* basis (based on the fraction of total MWh produced, i.e. diversity share). An example of this allocation is provided below, using three wind/solar resources:

- For a given exceedance factor, the wind/solar state QC is 75 MW. Each wind/solar resource (at the same exceedance factor) has Initial QCs as follows:
    - Resource 1: 30 MW Initial QC; 50% Diversity Share
    - Resource 2: 20 MW Initial QC; 30% Diversity Share

- Resource 3: 10 MW Initial QC; 20% Diversity Share

- The diversity benefit is 15 MW (wind/solar state QC minus sum of wind/solar Resource Initial QCs) is allocated in proportion to each wind/solar resource's diversity share. Note that this is achieved by multiplying the diversity share (resource MWh/{sum of state MWh} as described in Step 5, above) by the diversity benefit. The product of the diversity share and diversity benefit is added to the Initial QC.
- The calculated QC for each wind/solar resource is as follows:
  - Resource 1: 37.5 MW calculated QC
  - Resource 2: 24.5 MW calculated QC
  - Resource 3: 13 MW calculated QC

To calculate each month's final QC of a wind/solar resource, three most recent calculated QCs are averaged together. Or, in the case of a resource with fewer than three years of operating history, any calculated QCs are averaged with one to three estimated QCs. Three QC values (either calculated or estimated, or a combination) are averaged to calculate the final QC. For example, to calculate the 2010 QC of a unit that first operated during 2008, one calculated QC (2008) will be averaged with two estimated QCs (2006-7).

(END OF APPENDIX C)