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Decision 11-06-022 June 23, 2011

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations.	Rulemaking 09-10-032 (Filed October 29, 2009)

DECISION ADOPTING LOCAL PROCUREMENT OBLIGATIONS FOR 2012 AND FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM

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DECISION ADOPTING LOCAL PROCUREMENT OBLIGATIONS FOR 2012 AND FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM

1. Summary

This decision establishes local capacity procurement obligations for 2012 applicable to Commission-jurisdictional electric load-serving entities (LSEs). These procurement obligations are based on an annual study of local capacity requirements performed by the California Independent System Operator (CAISO) for 2012. The total local capacity requirements determined by the CAISO for all local areas combined decreased slightly from the prior year; the decrease is from 28,058 megawatts (MW) in 2011 to 26,778 MW in 2012. The existing capacity needed decreased from 27,094 MW in 2011 to 26,158 in 2012.

In addition, this decision adopts the following Resource Adequacy (RA) program refinements:

1. The Standard Capacity Product is now a mandatory part of the RA compliance program.
2. Penalties for RA program violations are modified to impose specific dollar penalties for deficiencies remedied within five business days after notification from Energy Division.
3. The LSE replacement rule remains in effect for the 2012 RA compliance year.
4. The Humboldt, North Coast/North Bay, Sierra, Stockton, Greater Fresno, and Kern local areas within the Pacific Gas and Electric Company (PG&E) territory (known as "other PG&E" local areas) are permanently aggregated for RA compliance purposes.
5. LSEs are no longer required to file a Preliminary Local Resource Adequacy Filing, and are no longer allowed to use Portfolio Resources as RA capacity.
6. The requirement that to qualify for RA requirements, a resource must be able to operate for a minimum of four hours per day for

three consecutive days, now will apply to all demand response resources in the RA program.

7. For 2012, demand response program totals allocated towards RA credit for the Base Interruptible Program, the Summer Discount Plan, and the Agricultural Pumping Interruptible Program shall be less than or equal to 543.9 MW for PG&E; 1087.8 MW for Southern California Edison Company; and 27.2 MW for San Diego Gas & Electric Company, subject to the conditions of a Settlement in Decision (D.) 10-06-034.
8. For the 2012 RA program only, PG&E is granted an exemption from the RA program requirement that demand response programs must operate from 1:00 p.m. to 6:00 p.m.

2. Background

Public Utilities Code Section 380 (as amended by Stats. 2008, ch. 558, Sec. 13, effective January 1, 2009) requires that "the Commission, in consultation with the [CAISO], shall establish resource adequacy requirements for all load-serving entities." The statute establishes a number of objectives for the Commission to achieve with the program, including development of new generating capacity and retention of existing generating capacity, equitable allocation of the cost of generating capacity, and minimization of enforcement requirements and costs. Section 380(j) defines "load-serving entities" for purposes of this section as "an electrical corporation, electric service provider, or community choice aggregator."

Based on the statutory language, the Commission's Resource Adequacy (RA) program and requirements apply to all load-serving entities (LSEs) under our jurisdiction. Certain small or multi-jurisdictional LSEs are subject to different RA requirements which are more appropriate to their situations than those described in this order. A current list of LSEs subject to the requirements of this decision is found in Appendix A.

This proceeding has been divided into two phases. Phase 1 considered local capacity procurement obligations for 2011 applicable to Commission-jurisdictional electric LSEs and several proposed RA program refinements. See D.10-06-036. That decision deferred issues related to local true-up provisions for RA, which were decided in D.10-12-038.

An *Assigned Commissioner's Ruling and Scoping Memo* (Scoping Memo), issued on November 3, 2010, identified the issues to be considered in Phase 2 of this proceeding as well as the procedure and schedule for their consideration. Two broad categories of issues were established. The first category, local RA issues, pertains to the California Independent System Operator's (CAISO) 2012 local capacity requirements (LCR) study as well as this Commission's establishment of local procurement obligations for 2012 based on the LCR study. The second category, program refinement issues, pertains to various proposals to modify the RA program.

In response to further comments and motions, the Scoping Ruling was revised on February 3, 2011 to allow the following issues identified by parties in their comments and Motions into the scope of the proceeding:

- How should the Commission determine the RA counting treatment of new generation resources that come online mid-year?
- A review of the Path 26 counting constraint allocation methodology;
- Whether to use of Southern California Edison Company's (SCE's) Planned Outage Adder instead of generator based replacement obligation proposed by the CAISO;
- Revisions to the Coincident Adjustment Factor;
- Modification of the citation program to provide for a specific cure period for RA showings found to be deficient;

- Whether Pacific Gas and Electric Company's (PG&E's) peak day pricing programs should receive credit for RA;
- The level of the waiver trigger for Local RA capacity;
- Refinement of the Standard Capacity Product;
- The role of multi-year RA contracts; and
- The interaction between the RA proceeding and the Commission's long-term procurement process proceeding.

In addition, the CAISO proposed to add to the scope of Phase 2 the following issue:

> Review the plan for a non-generic capacity procurement requirement process to add resource operational characteristics such as regulation and ramping "load following" capabilities into the RA procurement requirements. CAISO will provide an annual cycle of studies and reports to inform load serving entities' RA procurement. In addition, CAISO proposes that the Commission expand the five month year-ahead showing to a full years showing for the year-ahead procurement to support the evaluations and assessments of needed non-generic capacity.

In the revised Scoping Memo, this issue was deferred to a future phase of this proceeding.

The Commission's Energy Division facilitated workshops on RA program refinement issues on January 18 and 25, 2011. Comments on the Phase 2 issues discussed in the workshops were filed on February 8, 2011 by Alliance for Retail Energy Markets (AReM); Calpine Corporation (Calpine); the CAISO; California Large Energy Consumers Association (CLECA), Cogeneration Association of California (CAC); Division of Ratepayer Advocates (DRA); Dynegy Morro Bay, LLC, Dynegy Moss Landing, LLC, Dynegy Oakland, LLC and Dynegy South Bay, LLC (Dynegy); GenOnCalifornia North LLC and GenOn Delta LLC (GenOn); EnerNOC, Inc. (EnerNOC); PG&E; SCE; San Diego Gas & Electric

Company (SDG&E); and The Utility Reform Network (TURN). The CAISO; DRA; Dynegy; Independent Energy Producers Association (IEP); PG&E; SCE; SDG&E; and TURN filed replies on February 22, 2011.

Following a stakeholder process that began in 2008, on April 29, 2011, the CAISO posted its "2012 Local Capacity Technical Analysis Final Report and Study Results" (2012 LCR Study) on its website, served notice of the report's availability, and filed it with the Commission on May 2, 2011. To accommodate the CAISO's LCR study schedule and associated stakeholder review process, the Scoping Memo deferred the dates for comments and reply comments on local RA issues to May 6, 2011 respectively.

3. Local RA for 2012

3.1. 2012 Local Capacity Requirements Study

D.06-06-064 determined that a study of local capacity requirements (LCR) 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. The CAISO issued its final LCR report and study results for 2012 on April 29, 2011, and filed it on May 2, 2011. Comments were filed by TURN and SDG&E on May 6, 2011.

The CAISO states that the assumptions, processes, and criteria used for the 2012 LCR study were discussed and recommended in a stakeholder meeting, and that, on balance, they mirror those used in the 2007 through 2012 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.

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 at 21.) Each of the RA LCR decisions in the last four years adopted Option 2 as recommended by the CAISO for 2008 through 2011 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 2012. We therefore affirm the continued application of Option 2 to establish local procurement obligations for 2012.

The 2011 and 2012 summary tables in the 2012 LCR report, copied below, show that for all ten areas combined, the total LCR associated with reliability Category C decreased by over 1200 megawatts (MW) (or almost 5%) from 28,058 MW in 2011 to 26,778 MW. The existing capacity needed decreased from 27,094 MW in 2011 to 26,158 in 2012. The LCR needs have decreased in the following areas: North Coast/North Bay and Greater Bay Area due to downward trend for load; Sierra, Stockton, Fresno, Kern and San Diego due to downward trend for load and new transmission projects. The LCR needs have slightly increased in Humboldt due to load growth; Los Angeles Basin and Big Creek/Ventura due to small load growth as well as load allocation change (to conform with a new California Energy Commission (CEC) forecast).

2012 Local Capacity Requirements

	Qualifying Capacity			2012 LCR Need Based on Category B			2012 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	54	168	222	159	0	**159**	190	22*	**212**
North Coast / North Bay	131	728	859	613	0	**613**	613	0	**613**
Sierra	1277	760	2037	1489	36*	**1525**	1685	289*	**1974**
Stockton	246	259	505	145	0	**145**	389	178*	**567**
Greater Bay	1312	5276	6588	3647	0	**3647**	4278	0	**4278**
Greater Fresno	356	2414	2770	1873	0	**1873**	1899	8*	**1907**
Kern	602	9	611	180	0	**180**	297	28*	**325**
LA Basin	4029	8054	12083	10865	0	**10865**	10865	0	**10865**
Big Creek/ Ventura	1191	4041	5232	3093	0	**3093**	3093	0	**3093**
San Diego	162	2925	3087	2849	0	**2849**	2849	95*	**2944**
Total	**9360**	**24634**	**33994**	**24913**	**36**	**24949**	**26158**	**620**	**26778**

2011 Local Capacity Requirements

	Qualifying Capacity			2011 LCR Need Based on Category B			2011 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	57	166	223	147	0	**147**	188	17*	**205**
North Coast / North Bay	133	728	861	734	0	**734**	734	0	**734**
Sierra	1057	759	1816	1330	313*	**1643**	1510	572*	**2082**
Stockton	267	259	526	374	0	**374**	459	223*	**682**
Greater Bay	1210	5296	6506	4036	0	**4036**	4804	74*	**4878**
Greater Fresno	485	2434	2919	2200	0	**2200**	2444	4*	**2448**
Kern	699	9	708	243	0	**243**	434	13*	**447**
LA Basin	4206	8103	12309	10589	0	**10589**	10589	0	**10589**
Big Creek/ Ventura	1196	4110	5306	2786	0	**2786**	2786	0	**2786**
San Diego	194	3227	3421	3146	0	**3146**	3146	61*	**3207**
Total	**9504**	**25091**	**34595**	**25585**	**313**	**25898**	**27094**	**964**	**28058**

* CAISO note: No local area is "overall deficient". Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency the numbers are carried forward into the total area needs. Resource deficient sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

** CAISO note: Since "deficiency" cannot be mitigated by any available resource, the "Existing Capacity Needed" will be split among LSEs on a load share ratio during the assignment of local area resource responsibility.

TURN claims the CAISO's 2012 LCR study's finding regarding the LCRs in the SDG&E service territory are disappointing, because the study does not show expected significant ratepayer benefits of reduced LCRs associated with the new Sunrise Powerlink transmission line. TURN points to D.08-12-058, footnote 331, for example, as indicating that the Sunrise Powerlink Project would reduce SDG&E's LCRs by 1000 MW. However, the 2012 CAISO LCR study shows a reduction of only 140 MW. TURN claims that, while the CAISO report shows the Sunrise Powerlink project appears to not be providing the expected benefits yet, that project may do so in the future. Therefore, TURN recommends that the Commission direct SDG&E and the CAISO to pursue such benefits through technical and ratings mechanisms, such as examining the need for a new Local Area in the SDG&E region. TURN also urges the Commission to encourage SDG&E and the CAISO to temporarily suspend aspects of the LCR computational process which limits the calculation of LCR benefits.

SDG&E calls for the CAISO to conduct a supplemental seasonal LCR assessment for non-summer months using the results of a to-be-developed CEC non-summer one-in-ten-year forecast. The requested CAISO study would be used as part of the CAISO's 2013 Local Capacity Technical Study, to be incorporated (after stakeholder comment) into the March 2012 preliminary CAISO 2013 LCR study. The information then may or not be used for the 2013 LCRs, depending on stakeholder/CAISO discussion.

AReM, PG&E, SDG&E, TURN, DRA and the CAISO filed reply comments on LCR issues.

The comments reveal no disagreement with the CAISO's LCR determinations for 2012. As we noted in D.10-06-036 and in previous years, it appears that past efforts towards greater transparency and opportunity for participation in the LCR study process have paid off in significant part. We determine that the CAISO's final 2012 LCR study should be approved as the basis for establishing local procurement obligations for 2012 applicable to Commission-jurisdictional LSEs.

We recognize that TURN and SDG&E have raised important technical issues in their comments. These are issues which are properly considered at the CAISO before they can be incorporated into a decision here. We request that the CAISO perform the studies suggested by TURN and SDG&E and incorporate any significant findings and outcomes into the 2013 LCR study.

3.2. Local Procurement Obligations for 2012

3.2.1. Continuation of the Local RA Program

The RA program includes both "system" and "local" RA requirements. Each LSE must procure sufficient RA capacity resources to meet both obligations. "System" RA requirements are calculated based on an LSE's peak load plus a 15% planning reserve margin. "Local" RA requirements are calculated based on the CAISO's Local Capacity Technical Analysis, and are allocated to each individual LSE. Each LSE must then procure sufficient RA capacity resources in each Local Area to meet their obligation.

While several decisions over the past five years (most recently D.10-06-036) have defined the RA program, it remains necessary and appropriate to have a procedural mechanism in place to address the ongoing needs of the program. As the Commission stated in a June 2007 RA decision:

> While the nature of the future RA program and the associate procedural requirements cannot be fixed at this time, it is clear that there is an ongoing need for a procedural vehicle to address both modifications and improvements to the RA program as well as routine administrative (but not ministerial) matters that are not delegable to staff. Among other things, the local RA program component requires annual approval of LCRs based on the CAISO's LCR studies. For the near and intermediate term, we see a need for annual proceedings for these purposes." (D.07-06-029 at 52.)

D.06-06-064 adopted a framework for local RA and established local procurement obligations for 2007 only. D.07-06-029, D.08-06-031, D.09-06-028 and D.10-06-036 established local procurement obligations for 2008, 2009, 2010 and 2011, respectively. We intend that local RA program and associated regulatory requirements adopted in those decisions shall be continued in effect for 2012 and thereafter until changed, subject to the 2012 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. Once again, Energy Division should implement the local RA program for 2012 in accordance with the adopted policies.

3.2.2. Change to Coincident Adjustment Factor

The coincident factor is a number calculated by comparison of total aggregate LSE peak load forecasts and the coincident CAISO peak load, in order to make each LSE's peak load forecast reflective of the CAISO's peak load. This is used in determining RA obligations by adjusting individual LSE peak forecasts for the fact that each LSE may or may not peak at the time of the CAISO's coincident peak.

D.05-10-042 adopted the current coincident adjustment methodology, which uses an average coincident adjustment factor to take advantage of the pooling effect; that is, using an average factor partially balances out the fact that LSEs serve diverse customer classes.

This methodology uses historical coincident factors and the same coincident adjustment factor for all LSEs. The Commission adopted this method because "averaging is more stable and easier to calculate, monitor, and apply."[1] LSEs have both coincident demand (the level of an LSE's demand at the time of system peak demand) and non-coincident load (the peak level of demand on an LSE's system, which may not be at the time of system peak demand). Per D.05-10-042, each LSE's non-coincidental monthly demand is reduced by a factor that reflects the average load diversity in the CAISO's control area in that month.[2] This adjusted demand level is the basis for each LSE's RA obligations.

Historically, all customers were required to take all power from the monopoly investor-owned utilities (IOUs). In the 1990s, customers were allowed to take power from other electric service providers (ESPs), a service known as Direct Access. Direct Access was suspended in the early 2000s, due to adverse market conditions. However, existing Direct Access customers were "grandfathered" into their then-current contracts with ESPs. Direct Access reopened in 2010 under defined circumstances[3] for commercial & industrial customers, who again were allowed to begin migrating from their current ESP to another ESP.

AReM proposes changing the coincident adjustment factor. Instead of using a system average approach as adopted in D.05-10-042, AReM proposes using an approach that is more specific to LSEs. Specifically, AReM proposes developing three or more LSE load profiles categories: 1. LSEs serving all customers; 2. LSEs serving commercial and industrial customers only; and 3. LSEs serving only residential and small commercial customers. Each LSE

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[1] D.05-10-042 at 38.

[2] *Id*.

[3] D.10-03-022.

would be assigned to the load profile category that reflects their load profile. Based on the load profile categories, the CEC would establish three average coincident adjustment factors and apply the adjustment factor to the LSEs associated with each category.

AReM argues that since ESPs serve mainly commercial and industrial customers, the current system average approach competitively disadvantages the ESPs, compared to other LSEs, and shifts costs to direct access customers.[4] This is because IOUs have an obligation to serve all customers, while ESPs do not. Thus, according to AReM, using the averaging approach allocates more RA costs to some ESPs and fewer costs to IOUs than if RA costs were allocated based on which customers are actually served by that entity.

Additionally, AReM contends that the re-opening of direct access adds to the problem because "since the market re-opening, ESPs have added commercial and industrial load, thereby increasing the 'peakiness' of [IOU] loads that have lost commercial and industrial customers. However because each LSE's RA requirements are calculated using the single, system average coincident adjustment factor, the additional 'peakiness' present in other LSE's load profiles, since market re-opening, is not appropriately reflected in their RA capacity obligations." [5]

DRA opposes any changes to the coincident adjustment factor until a full review of all relevant factors occurs.[6] TURN opposes AReM's proposal to change the Coincident Adjustment Factor, contending that this proposal "is one

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[4] AReM Motion to Add to Phase 2 Scope at 3.

[5] *Id*.

[6] DRA Reply Comments on Phase 2 Proposals at 4.

step on a road toward the selective deconstruction of bundled loads by non-IOUs LSEs that could leave the IOUs serving only the 'peakiest,' most expensive loads."[7] In reply comments, TURN agrees with SCE and PG&E that more implementation efforts need to be given on this issue.

PG&E recommends moving this issue into the 2013 RA proceeding because the issue will entail a fairly detailed analysis of alternative load profiles, how they would be constructed, and how they would be applied.[8] SCE opposes AReM's proposal. Because of the complexity of the issue, SCE says "if the Commission does intend to change the current methodology, it should complete a full review and consider all of the factors that contribute to the coincident adjustment factor, such as location, and not simply load shape."[9]

CLECA supports AReM's proposed method over the current method as more equitable and cost-based.

Discussion:

D.05-12-042 adopted the average coincidence adjustment in 2005 partially due to administrative simplicity and overall fairness. Since 2005, conditions have changed. The argument for simplicity is no longer valid. The CEC currently does not use an average coincidence factor in developing forecasts in its Integrated Energy Policy Report process, but instead applies a coincidence factor to each type of load class based on analysis and determinations supporting greater accuracy. The CEC uses a different coincidence factor to determine LSE

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[7] TURN Comments on Phase 2 Proposals at 4.

[8] PG&E Comment on Phase 2 Proposals at 16.

[9] SCE Comments on Phase 2 Proposals at 3.

specific loads. Harmonizing the two coincidence factors would promote greater simplicity, as well as improve cost allocation related to cost causation. Coincidence factors for bundled customers served by IOUs and ESPs are estimated separately, taking into account the customer mix of ESPs versus IOUs, and the restriction on residential load migration.[10]

The average coincident factor method is also inconsistent with methods used to develop a bundled customer forecast in support of the Commission's long-term procurement process. In both RA and long-term procurement proceedings, the Commission has determined that the adopted CEC forecast is to serve as the reference case. The CEC also provides LSE-specific coincidence adjustments to each California LSE which is outside of the Commission's jurisdiction for LSEs' use in CAISO RA compliance filings. Adopting an LSE-specific methodology for RA would harmonize the long-term procurement process and RA procurement process, as well as improve cost allocation related to cost causation.

TURN's concern is that IOU bundled customers may experience adverse rate impacts because the IOUs, because of their obligation to serve and the fact that they serve nearly all residential customers, on average serve more costly customers. TURN provides no analysis of specific impacts. While changes to the coincident adjustment factor would not directly change the overall distribution of customers among all LSEs, it would change the allocation of costs among LSEs. It is possible that more accurate reflection of cost drivers for different LSEs would increase the incentive for some customers to migrate from IOUs to ESPs,

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[10] *See* p. 51 in http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF.

as ESPs' costs decrease and IOUs' costs increase. However, there is no data showing this would be a significant factor. Further, current Direct Access rules provide very limited ability currently for customers to move between IOUs and ESPs. Therefore, any changes in cost allocation resulting from changes to the coincident adjustment factor would appear to be minimal.

We are committed to greater cost transparency and cost allocation based on cost causation for the RA program. All customer classes should be aware of the costs unique to the "peakiness" of that particular customer class, and all LSEs should face costs consistent with cost causation. An average coincidence factor across all customer classes hides certain cost differences among classes and LSEs. In essence, this method serves as a cross subsidy from industrial and commercial customers to residential customers.

Nevertheless, we will not adopt AReM's proposal at this time. We agree that there is significant technical analysis which remains to be produced before this proposal can be implemented. We request Energy Division and CEC staff to work to refine this concept over the course of the next year and provide a recommendation to the Commission in next year's RA proceeding for further consideration and possible implementation in 2013.

3.2.3. Mandating the Standard Capacity Product for Resources with Historical Qualifying Capacity

The Standard Capacity Product is a system of availability metrics and performance penalties that RA resources face if they are subject to forced outages at rates above the overall fleet average. D.09-06-028 deferred action on mandating the Standard Capacity Product for RA compliance due to the fact that Federal Energy Regulatory Commission (FERC) approval of the Standard Capacity Product tariff was still pending. On June 28, 2009, FERC approved the existing Standard Capacity Product tariff which exempted certain resources, including resources whose Qualifying Capacity was based on historical data and demand response (DR) resources. However, the CAISO was unable to create appropriate availability and performance standards for these types of resources within the timeline of the Standard Capacity Product stakeholder process. In its order, FERC directed the CAISO to work toward extending the Standard Capacity Product to currently exempt resources.[11]

During Phase I of this proceeding, parties addressed the exemption of resources with Qualifying Capacities based on historical production data. The main issue impeding these resources from becoming a part of the Standard Capacity Product was a potential double penalty issue for outages: one penalty that would result in the reduction of the Qualifying Capacity value of the resources and second financial penalty from the Standard Capacity Product availability standard. D.10-06-036 adopted a Qualifying Capacity methodology for these resources that eliminated the double penalty issue. The adopted counting methodology for these resources now subtracts any outage hours from historical load information before calculating a resources Qualifying Capacity. The decision further allowed use of the Standard Capacity Product for RA compliance by these previous exempt resources, but did not require it.

In 2010, the CAISO ran a stakeholder proceeding to develop the Standard Capacity Product II, which would address resources that were exempt from the original Standard Capacity Product because their Qualifying Capacity values were determined using historical data. The CAISO filed a proposed Standard

[11] D.10-06-036 at 20.

Capacity Product II tariff at the FERC in June of 2010 to address such resources. This proposed tariff language continued the express exemption of DR resources from the Standard Capacity Product.

In Phase 2 of this proceeding, the CAISO proposed that the Commission mandate compliance with the Standard Capacity Product for resources using the historical Qualifying Capacity method. The CAISO argues that this was appropriate because D.10-06-036 eliminated the double counting concern that had been the reason for the CAISO deferring application of the Standard Capacity Product to those resources. The CAISO urges the Commission to mandate compliance with the Standard Capacity Product by these resources.[12]

SCE opposes the CAISO's proposal because DR and other energy technologies are not yet included in the Standard Capacity Product. Also SCE contends the Standard Capacity Product is not a fully standard fungible product because the CAISO is seeking to add non-generic operational characteristics to the RA obligations.

Discussion:

D.10-06-036 altered the RA net qualifying capacity rules to accommodate the Standard Capacity Product performance and availability provisions that are now accepted by FERC and in effect starting January 1, 2011. The net qualifying capacity rules were modified to create proxy values for each resource for hours in which the resource was impacted by forced outage. This removed the "double penalty" issue seen when units on forced outage are penalized via the performance and availability penalties in the Standard Capacity Product and

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[12] CAISO Comments on Phase 2 Proposals at 10.

also have their Qualifying Capacity impacted by the low performance of that hour.

The Standard Capacity Product will now be a mandatory part of the RA compliance program. There is now no barrier to use of the Standard Capacity Product penalties and availability metrics for all resources which are covered by a currently adopted CAISO Standard Capacity Product program (which does not currently include DR programs). It is also reasonable to mandate the use of such penalties and metrics in RA contracts going forward. SCE's concern that the Standard Capacity Product is not fully robust yet because certain technologies are not included is not sufficient to prevent adoption for technologies which are covered by the CAISO program. Expansion of the Standard Capacity Product is an incremental process. There is no harm in expanding it to more resources now, and then evaluating further expansion to DR resources and other technologies in the future.

The Energy Division should monitor further developments regarding the Standard Capacity Product at FERC in order to implement the current Standard Capacity Product program, as well as to consider whether to recommend to enlarge the program in future RA proceedings to incorporate provisions for DR resources.

3.2.4. Cure Period for RA Procurement Deficiencies

Violations of RA requirements in Commission decisions are subject to Commission-imposed penalties. The penalties were first established in D.05-10-042. Penalties may be imposed for procurement deficiencies, late filing, or other reasons, subject to the current penalty structure adopted in D.10-06-036 and implemented by Energy Division in compliance with Resolution E-4195. RA filings are validated by Energy Division for compliance with Commission directives. Potential violations are identified by Energy Division and may be referred to the Consumer Protection and Safety Division for enforcement.

D.10-06-036 adopted a revised penalty structure for violations of RA requirements. That decision contained penalties for deficiencies that are remedied within five business days. This provision brought greater clarity to the role of Energy Division staff in validating RA Filings, and created clear differences in penalties between deficiencies that are remedied within five business days and those that are not. The penalty structure in D.10-06-036 provided that penalties are levied in every case where a deficiency is identified as of the LSE's filing due date. The current penalty structure takes a strict view of RA compliance, and does not contain a provision where deficiencies related to errors or mistakes would not trigger penalties.

AReM proposes to alter that strict view of RA compliance whereby Energy Division staff could notify LSEs of deficiencies and LSEs would be able to remedy these deficiencies in RA filings in a short timeframe as part of the normal validation process. AReM proposes that an LSE have five business days from the date of Energy Division notification of the deficiency/error to make a corrected RA filing without incurring a deficiency penalty. AReM proposes that if the LSE cures the deficiency within five calendar days, the only penalty would be the applicable late filing penalty specified in Resolution E-4195. If not corrected in the requisite period, then the applicable deficiency penalty adopted in D.10-06-036 would apply. AReM argues that the CAISO provides RA suppliers with ample time to correct deficiencies in their supply plans without being penalized, and that the Commission should align the RA buyer rules with the CAISO's RA supplier rules.

DRA does not believe it is necessary to revisit this issue now since the RA penalty structure and cure period was recently considered in D.10-06-036. DRA argues that the "duty to submit accurate and timely filings showing adequate procurement should remain with the LSEs. Removing the filing and procurement penalties in a newly-created grace period does not support the goals of the RA program." [13]

PG&E and Calpine support the AReM proposal. Calpine contends that this proposal provides parties with reasonable opportunity to correct deficiencies while maintaining reliability. Furthermore, Calpine observes that the proposal imposes penalties retroactively to the date that a deficiency is first noticed when the deficiency remains uncured after the five day period.[14] SDG&E supports AReM's proposal but suggests limiting applicability of the cure period to unintended clerical errors.

Discussion:

The history of the RA program this far has illustrated high levels of compliance and productive cooperation[15]. AReM's proposal asks the Commission to reconsider the strict enforcement policy whereby LSEs are potentially subject to penalties in the event a procurement deficiency is identified by Energy Division during the course of validation.

AReM is correct that the current penalty structure at times penalizes LSEs for mistakes that are identified by agency staff soon after filings are submitted

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[13] DRA Reply Comments on Phase 2 Proposals at 3.

[14] Calpine Comments on Phase 2 Proposals at 2-3.

[15] The history of compliance is supported by Commission annual RA reports, available here: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/.

each month. Because the RA program is complicated, at times some days elapse before either LSEs or agency staff become aware of a minor deficiency.

We adopt AReM's proposal with modifications. We will alter the penalty structure in D.10-06-036. The table below retains penalties for deficiencies not remedied within five business days.

	System Procurement Deficiency (modifying D.10-06-036 Ordering Paragraph 6g)	Local Procurement Deficiency (modifying D.10-06-036 Ordering Paragraph 6g)
Deficiency remedied after five business days from the date of Energy Division notification or not remedied at all	$6.66/kilowatt-month	$3.33/kilowatt-month

In addition, we will modify Appendix A to Resolution E-4195 to incorporate the creation of a new Specified Violation with a $5,000 or $10,000 penalty for LSEs (depending upon the size of the deficiency) that remedy deficiencies within five business days after the initial notification by Energy Division. This new Specified Violation will replace in total the current Specified Violation for Small Procurement Deficiencies. Other Specified Violations from Appendix A will remain and continue to be used.

In order to prevent LSEs from manipulating the new penalty structure, and to ensure that staff time is not wasted with intentional errors, we will double the penalty to $10,000 or $20,000 if Energy Division finds that an LSE has a second deficiency. This higher penalty applies only when Energy Division finds a subsequent deficiency in any filing within a compliance year after a first deficiency is found and cured within five business days, and the LSE also cures the second deficiency within five business days; otherwise the penalties per kilowatt (kW)/month apply.

We also reiterate that, in enforcing compliance with RA filing requirements, or in response to any Specified Violation, the Commission may initiate any authorized formal proceeding or pursue any other remedy authorized by the California Constitution, the Public Utilities Code, other state or federal statutes, court decisions or decrees, or otherwise by law or in equity. Finally, the Commission's enforcement of this Resolution by informal proceedings, formal proceedings, or otherwise, does not bar or affect the remedies otherwise available to other persons or government agencies.

The new Specified Violation will be as follows:

Specified Violation	**Deficiency in either System or Local RA Filing (Modifying Appendix A in Resolution E-4195)**
Deficiency cured within five business days from the date of notification by the Energy Division	$5,000 per incident if the deficiency is 10MW or smaller, $10,000 for a deficiency larger than 10 MW. For the second and each subsequent deficiency in any calendar year, penalties will be $10,000 per incident if the deficiency is 10 MW or smaller, $20,000 for a deficiency larger than 10 MW.

3.2.5. Outage Replacement Obligation and Planned Outage Adder

The Commission's RA policy adopted in D.06-07-031 includes what is know as the "LSE replace" rule, whereby LSEs are only able to count generating units that are not impacted by scheduled outages towards meeting their RA obligations. Generating units are to notify LSEs with whom they have transacted for RA capacity as to when the unit will be on outage. Some generating units also supply other capacity for the LSE to include in the RA filing to make up for the capacity ineligible due to scheduled outage. With this information, LSEs can calculate how much RA capacity they can count from a unit via a formula adopted in D.06-07-031. This formula is also included in the Commission's RA Guide. During validation of RA filings, the Energy Division checks and verifies RA filings with outage information to confirm that the scheduled outage formula is applied correctly.

CAISO outage coordination maintains the system of receiving outage requests from all generators within the CAISO system regardless of their RA commitments. The CAISO approves or denies outage requests on all units in its jurisdiction. Due to the annual nature of the Local RA obligation, the CAISO is able to allow some portion of the units committed as Local RA to go on outage as part of the CAISO's real-time optimization program.

With our adoption of the FERC Standard Capacity Product tariff in 2006, we determined that the current LSE based replacement obligation for RA capacity[16] for scheduled outages stands in the way of the making the Standard Capacity Product commercially viable because LSEs still need to negotiate complex replacement provisions in each contract individually. This may require the sharing of confidential information between suppliers and LSEs, or may require financial provisions to be negotiated. In Phase 1 of this proceeding, two methods were proposed to end the current LSE-replacement obligation:

1. A CAISO tariff-based replacement approach that requires suppliers to replace capacity of scheduled outage.
2. A Planned Outage Adder method that allows each LSE to avoid managing outages on units they have contracted for RA purposes, and instead rely on the CAISO to manage outages. In this proposal, LSEs would provide the CAISO with a larger pool

[16] This rule was adopted in D.06-07-031 at 10.

> of resources to account for outages on units that all LSEs have contracted for. The Planned Outage Adder would be calculated from the historical data on CAISO-approved planned outages, and would be added on top of the reserves that LSEs normally are required to contract for and commit to the CAISO.

D.10-06-036 did not adopt the Planned Outage Adder method because the proposal at the time lacked specific details. The decision also did not adopt the CAISO tariff-based replacement method because it did not appear viable. The decision encouraged the CAISO and other parties to further explore the tariff replacement method. Following D.10-06-036, the CAISO opened a scheduled outage replacement stakeholder process to explore development of a supplier based replacement provision. That process has been stalled since late August 2011.

Energy Division proposes that once the FERC adopts a supplier based replacement rule that meets the criteria outlined in Energy Division's November 30, 2010 proposal (where suppliers of RA capacity would be responsible for the effects of their outages), that the Commission should eliminate the "LSE replace" outage counting provisions adopted in D.06-07-031.

SCE again proposes the use of a Planned Outage Adder. This is the same method SCE proposed in Phase 1 of this proceeding. As opposed to the Energy Division's proposed "supplier replace" rule, SCE's proposed Planned Outage Adder is an amount in MW that is added on top of the RA obligation, meant to approximate the amount of RA units that are affected by scheduled outages in a month. The Planned Outage Adder fluctuates by month based on the amount of historical scheduled outages taken in a month.

GenOn opposes the Energy Division's proposed supplier replace approach and supports SCE's Planned Outage Adder proposal. GenOn argues that Energy

Division's proposal is relatively inefficient and would lead to higher ratepayer costs.

CAC supports SCE's proposal because it "achieves the goal of a fungible capacity product … and keeps the scheduled outage replacement obligation in the hands of the LSEs, the parties most able to efficiently procure low-cost RA capacity".[17] CAC opposes Energy Division's proposal because it makes the "assumption that all RA capacity suppliers are not only in a position to secure replacement obligation but will do so as a normal course of their electric supply business. … The assumption is misplaced for Independent Resources, many of which are preferred combined heat and power, wind and solar facilities, which do not universally have access to a low-cost portfolio of alternative sources of capacity."[18]

AReM supports the RA replacement obligation in the CAISO tariff. AReM supports Energy Division's proposal in principle, but believes it provides too much flexibility to the CAISO to do nothing.[19] AReM recommends setting a date certain by which the Commission will automatically terminate the LSE's obligation. AReM does not support SCE's Planned Outage Adder proposal because "it would : (a) significantly increase the RA procurement obligation for LSEs; (b) require procurement of RA capacity whether or not it is needed by the CAISO; (c) exacerbate cost shifting and create subsidies among LSEs; and (d) significantly increase costs to consumers."[20]

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[17] CAC Comments on Phase 2 Proposals at 7.

[18] *Id*. at 2.

[19] AReM Comments on Phase 2 Proposals at 7.

[20] *Id*. at 5.

DRA supports Energy Division's proposal. DRA also believes that SCE's proposal deserves more consideration. TURN opposes SCE's Planned Outage Adder proposal. TURN argues that adding a Planned Outage Adder to LSE's RA requirements would impose, in effect, an increase in the Planning Reserve Margin in non-peak months without any demonstration that such extra capacity is actually needed.[21]

PG&E opposes Energy Division's proposal. PG&E says it is not prepared to support SCE's Planned Outage Adder proposal because PG&E has not been able to fully evaluate how much extra RA capacity it would require LSEs to procure. In addition, PG&E is concerned that the SCE proposal might not reflect current system conditions because it is based on historical data. PG&E contends that SCE's proposal will result in the socialization of planned outages, and may give less of an incentive to RA resources to limit the number of planned outages taken.

CLECA supports Energy Division's proposal of moving the replacement obligation from the LSE to the generator. Additionally, CLECA proposes that a one week outage should trigger a replacement, and that the replacement capacity should have similar availability attributes to what is being replaced. CLECA maintains that these requirements should not be discriminatory; instead, they should apply to all RA capacity.

Dynegy opposes Energy Division's proposal to transfer the replacement obligation from the LSE to the generator. Dynegy does not believe it has the information and technical expertise to manage outage risk that AReM asserts the

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[21] TURN Comments on Phase 2 Proposals at 2.

seller posses.[22] Dynegy urges the Commission to further explore SCE's Planned Outage Adder approach.[23] IEP also opposes Energy Division's proposal, contending that "shifting part of that obligation to a contractual counterparty could put the seller in an awkward position with competitive implications."[24]

SCE opposes Energy Division's proposal. SCE states, "If the Commission is not inclined to adopt the [Planned Outage Adder] proposal at this time, the Commission should retain the current planned outage counting rule and decline to restrict future options to a CAISO tariff-based replacement."[25]

Calpine believes that SCE proposal is workable. Calpine is concerned that the proposal fails to provide an incentive to limit the scheduled outages of specific resources. Calpine recommends that this could be addressed in two ways: "First, the CAISO simply could limit excessive outages by exercising discretion to deny scheduled outages that potentially threaten reliability. Second, the CAISO could incorporate scheduled outages that exceed a certain threshold into the calculation of availability that is used to determine Standard Capacity Payment availability incentives."[26]

SDG&E recommends use of the Planned Outage Adder over the alternative proposals. However, SDG&E states that SCE's proposal lacks the data to fully analyze the impact the Planned Outage Adder would have on RA program. SDG&E recommends that the CAISO be asked to produce the data

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[22] Dynegy Reply Comments on Phase 2 Proposals at 4.

[23] *Id*. at 5.

[24] IEP Reply Comments on Phase 2 Proposals at 5.

[25] SCE Comments on Phase 2 Proposals at 2.

[26] Calpine Comments on Phase 2 Proposals at 4.

requested by SCE so that all stakeholders may make informed decisions before weighing in on SCE's Planned Outage Adder proposal.[27]

Discussion:

We share parties' concerns with both SCE's Planned Outage Adder proposal and the Energy Division proposal.

The Planned Outage Adder would essentially increase the Planning Reserve Margin by requiring all LSEs to contract for additional RA capacity regardless of the CAISO's need for it and whether RA units actually go on outage. In addition, under SCE's approach, neither a generator on outage nor the LSE that contracted with that generator would be required to mitigate the impacts. We find that the Planned Outage Adder proposal is less consistent with Commission goals of cost causation and cost minimization than the current scheduled outage requirement (the "LSE replace" rule).

We also note other unresolved concerns with the Planned Outage Adder approach that were raised at workshops. For example, there may be no incentive to conduct maintenance efficiently, and the Planned Outage Adder may represent a large cost shift from those that own or contract for very large generators to those that do not. Further, there appears to be no ability to relieve LSEs of the Planned Outage Adder obligation nearer to the compliance month if it is found that extra resources are not needed to maintain reliability. Additionally, the Planned Outage Adder continues to require LSEs to bear the costs of managing scheduled outages on generators over which they have

[27] SDG&E Comments on Phase 2 Proposals at 12.

limited control instead of putting that responsibility on the generators that take those outages.

LSEs are not informed sufficiently to be able to pick which particular generators are most needed for reliability. This is a concern with the current outage rule as well. Generators may not know precisely which units are most needed for reliability either, but if generators are honest when stating they are not equipped to procure capacity to cover their own outages, then they are in the same position as the LSEs, who know even less about how generators operate and certainly know less then generators about when generators need maintenance and how long the work needs to last. Under the Planned Outage Adder, LSEs would not even know which generators are taking outage, which represents more uncertainty for LSEs relative to the current rule.

For all of these reasons, as compared to other alternatives in this record, we find that the Planned Outage Adder would be significantly more likely to create a more inefficient procurement relative to the current LSE replace rule. We therefore reject this approach.

Several parties suggest that it is unclear what value the current scheduled outage rule provides in terms of reliability risk avoided by the rule. In addition, there is a significant administrative effort that goes into implementing the current rule. We agree that the current rule is unwieldy.

However, we have considered the comments of the CAISO and other parties on the Proposed Decision. These parties expressed substantive concerns about eliminating the LSE replacement rule at this time without a specific alternative. Based on these comments, we are persuaded to delay removal of the replacement rule until compliance year 2013. We strongly encourage the CAISO to quickly begin working with all stakeholders to develop the necessary procedures and tools to reliably operate without the current replacement rule. The replacement rule will remain in effect for 2012, but will be removed for compliance year 2013 and beyond.

Because this is a temporary policy, a future phase of this or the successor RA proceeding will evaluate the effects of the current policy. We direct Energy Division to work with the CAISO and stakeholders to develop an alternate to the LSE replacement rule which can be implemented by the start of the 2013 RA compliance year.

3.2.6. Modification to Local RA Waiver Trigger Price

In Rulemaking (R.) 05-12-013 (the first RA Rulemaking proceeding), a staff report analyzed market power in transmission constrained areas. The report considered the need to adopt a local waiver process so that LSEs would not be subject to market power in transmission-constrained local areas. D.06-06-064 relied on the staff report, noting its conclusion that "without such a waiver option, LSEs that are unable to bilaterally contract for local capacity needed to meet their assigned obligation would be subject to both backstop procurement costs and potential penalties. Under a waiver process, the Staff Report suggests, an LSE would be able to request relief from the procurement obligation with a demonstration that it has made every commercially reasonable effort to contract for Local [Resource Adequacy Requirement] resources."

D.06-06-064, Conclusion of Law 27, determined that a local waiver process was "necessary as a market power mitigation measure, and should therefore be adopted as a component of the Local [Resource Adequacy Requirement] program." Conclusion of Law 26 in that decision determined that a monthly price trigger of $40 per kW-year was a "reasonable and appropriate measure of the cost of new capacity for purposes of both Local and System [Resource Adequacy Requirement] penalties."

IEP proposes that the Commission revise the waiver trigger price. IEP contends that the continued existence of the waiver trigger undermines the Commissions fundamental program objective of providing appropriate incentives for investment in generation resources where they are needed. In reply comments, IEP urges the Commission to "revise the local RA waiver trigger level to reflect the current cost of generating capacity or, at a minimum, to a level equaling the compensation for backstop capacity that FERC ultimately approves for the Capacity Procurement Mechanism."[28]

AReM opposes IEP's proposal to modify the trigger price. AReM states that while it "does not oppose re-evaluation of the trigger amount, from time-to-time, any proposals should be presented in a stakeholder forum, where the details of the proposed changes can be fully vetted and discussed against the backdrop of the waiver trigger policy."[29]

DRA disagrees that the year-ahead RA program will provide an incentive for new generation in local areas, regardless of whether the local waiver trigger price is increased. TURN does not believe there is an obvious need to change the waiver trigger at this time.[30]

Calpine supports IEP's proposal to revise the waiver trigger price. Calpine argues that the current waiver trigger price is "too low to encourage investment or even prudent maintenance and cost-effective upgrades to capacity in the

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[28] IEP Reply Comments on Phase 2 Proposals at 7.

[29] AReM Comments on Phase 2 Proposals at 8.

[30] TURN Comments on Phase 2 Proposals at 5.

locations in which it is most needed. In addition, Calpine states the current waiver trigger price is now significantly lower than the $55/kW-year price that the CAISO has proposed to pay for capacity that it will procure through its backstop Capacity Procurement Mechanism."[31] Dynegy also supports IEP's proposal to revisit the waiver trigger price. Dynegy states: "The now nearly five-year-old $40/kW price was based on a price offered in a Section 206 complaint filed in 2005 and an estimate of net market revenues made prior to the implementation of the CAISO's nodal market. There is no reason to expect that this old information now reflects the current net cost of new capacity, which…the waiver trigger is supposed to reflect."[32]

SCE opposes the IEP proposal to raise the waiver trigger price.

GenOn supports the update of the waiver trigger price. GenOn argues that the waiver trigger price of $40 per kW-year adopted in 2006 had little, if any, relationship to the cost of capacity because it was a compromise figure emanating from a settlement negotiation in a FERC proceeding. GenOn also contends that, nevertheless, the waiver trigger price has served as to dampen, if not cap, capacity pricing at an artificially low level.[33]

Discussion:

We will not change the RA trigger waiver price at this time. In its 2010 Energy Division RA Report, Energy Division found that the median price paid

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[31] Calpine Comments on Phase 2 Proposals at 6.

[32] Dynegy Comments on Phase 2 Proposals at 15-16.

[33] GenOn Comments on Phase 2 Proposals at 3.

for RA capacity, both System and Local, was well below the trigger price level.[34] The intent of creating a local waiver mechanism was to protect against market power in locally constrained areas where generators could potentially charge very high capacity prices to LSEs because they had a RA obligation in the local area and would otherwise face RA penalties. The waiver trigger price has been applied for only three times (and granted twice) since the 2007 compliance year. The fact that the waiver has been rarely used since its adoption in 2006 shows that LSEs do not appear to be subject to market power in such a way as to make compliance with RA obligations impossible.

3.2.7. Change to Path 26 Allocation Process

Path 26 is a transmission line connecting SCE with PG&E between the Midway and Vincent substations. Because there are resources on either side of Path 26 which provide benefits to the CAISO relative to where load is, and Path 26 is limited by its path rating, there was a need to determine an allocation of Path 26 capacity for RA purposes. The Commission adopted the current Path 26 allocation in D.07-06-029. The CAISO allocates a portion of the transfer capability on the path to LSEs based on proportionate share of a CAISO area peak. Part of the allocation process is the voluntary submission of contracts in opposing IOU service territories in order to mathematically enlarge the transfer capacity of Path 26. The current process allocates the benefits (in terms of extra MW of transfer capability on Path 26) to all LSEs. The extra MWs of transfer capability on Path 26 are enabled by individual contracts between load in one service territory and RA capacity in another.

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[34] http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/.

SCE proposes a change to the Path 26 allocation process from its current load ratio methodology to an allocation methodology that reallocates the additional capacity obtained from the north-to-south and south-to-north netting process, to those entities that provide the counterflows necessary to free up the additional capacity. SCE argues that the current Path 26 allocation methodology unfairly shifts available capacity remaining after the north-to-south and south-to-north "netting" process to entities that do not contribute to relieving the constraint, through the load-ratio share allocation process.[35]

AReM opposes SCE's proposal to change the current Path 26 allocation process, stating: "SCE's proposal would only benefit LSEs with loads on one side of the constraints (i.e., the IOUs) and, thus, would not benefit ESPs, whose load is typically in each IOU jurisdiction. Therefore, SCE's proposal is discriminatory and should be rejected. AReM notes that any allocation method other than load-ratio share is unduly discriminatory in an RA program in which all LSEs have the same obligation to comply."[36]

PG&E supports SCE's proposal.

SDG&E supports adding the extra step proposed by SCE to the Path 26 allocation process. Additionally SDG&E offers the following modifications to SCE's proposal:

1. The amount that is netted should be the lower of the two sums (north-to-south or sum of south-to-north);
2. The netting should be based on a pro-rata share of the directionally greater nominations;

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[35] SCE Phase 2 Proposals at 3.

[36] AReM Comments on Phase 2 Proposals at 9.

3. RA capacity that is based on intermittent or use-limited resources or option contracts should be excluded from the netting process; and
4. Any excess amounts of RA not netted through the process should be used to create extra counterflow capacity in the load share allocation step.

In reply comments, SDG&E notes that the last step of its proposed modification would be in conflict with the Path 26 Counting constraint. SDG&E also recommends that "only fully executed RA contracts on non-use-limited resources be eligible for the netting process, and that derivatives of such contracts, including call options or contracts that are contingent on Path 26 capacity allocation, be deemed ineligible in order to reduce the potential for gaming the netting process."[37] Additionally, SDG&E does not believe that AReM's claim that only IOUs benefit from the netting is accurate. SDG&E contends that any LSE will benefit if it has a non-grandfathered RA contract serving load on both sides of the path which needs Path 26 capacity.

DRA believes the proposal merits further consideration for possible increased efficiency, and that potential cost reductions be evaluated. DRA shares SDG&E's concern that there is a possibility for gaming the system.

Discussion:

We will retain the current Path 26 allocation process. The Path 26 process is intended to promote reliability by ensuring that LSEs procure resources both north and south of Path 26 regions. Increased capacity created by netting is not the same as real capacity on the line. In terms of additional reliability benefits,

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[37] SDG&E Reply Comments on Phase 2 Proposals at 5.

there does not appear to be great value to changing the already complex Path 26 allocation process.

3.2.8. Change to Year-ahead Forecast Timeline

D.05-01-042 adopted an informal process for LSEs to dispute and revise their year ahead RA forecasts, but failed to set clear timelines on the process. The current RA process requires LSEs to submit year ahead forecasts of customers in April, and for Energy Division to distribute RA obligations including System and Local RA requirements. That translates to a six-month lag between submission of LSE forecasts and demonstration of compliance with those forecasts.

To clarify that process, Energy Division proposed to establish firm deadlines for revisions and to provide a chance for LSEs to update information after the initial information is submitted. Energy Division proposed to set a firm deadline for LSEs to submit revisions to their forecasts. By July 25th of each year, Energy Division would notify LSEs of their Final RA allocations and obligations. LSE would be given to August 19th of each year to submit any changes to their load information that would change their allocations. Energy Division would distribute revised RA allocations and obligations by September 15th of each year (45 days before the year-ahead filing). Energy Division provided three different timelines for how the 2012 RA process could take place.

AReM does not support the adoption of a firm date for LSEs to submit revisions to their year-ahead RA forecasts. AReM is concerned that the revised obligations will prevent LSEs from participating reasonably in the IOU RA solicitation process, and that IOUs will be unable to adjust the timelines of their solicitations to accommodate any changes to timelines. AReM claims that this late notification of final RA requirements would further delay the IOU's process for selling excess Local RA to other LSEs, and otherwise limit the ability of LSEs to make the necessary RA purchases.[38]

PG&E stated that it could make adjustments to its solicitation process to accommodate Energy Division's year-ahead load forecast timeline with two modifications: "First, submitting load forecast adjustments for load migration must be mandatory for all LSEs, rather than be at the LSE's discretion as proposed by Energy Division. This is needed to prevent LSEs from gaming the process to avoid responsibility for their share of RA procurement. Second, day-to-day extension must be provided in the year-ahead compliance filing date for any delay in the Energy Division's provision of revised RA requirements to LSEs."[39]

Calpine supports Energy Division's year-ahead forecast timeline proposal because revisions to load forecasts have become increasingly important with the limited reopening of Direct Access. Calpine believes Energy Division's second and third proposed timelines provide adequate time for LSEs to complete year-ahead procurement once revisions to year-ahead forecasts are complete and associated year-ahead procurement obligations are determined.[40]

Discussion:

We agree with Calpine that the opportunity to revise forecasts is becoming increasingly important, given the greater level of uncertainty regarding future loads and customer retention. Reopening Direct Access under the schedule

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38 AReM Comments on Phase 2 Proposals at 10.

39 PG&E Comments on Phase 2 proposals at 12.

40 Calpine Comments on Phase 2 proposals at 2.

adopted in D.10-03-022, while related to the timelines of the RA program, can still cause migration on intervals that come closer to compliance filings with less time to process and allocate responsibilities.

We find it appropriate to provide added flexibility for LSEs to adjust their RA forecast. We adopt Energy Division's proposed timeline #3, shown in the table below. The Assigned Commissioner or Administrative Law Judge (ALJ) may modify these dates if necessary.

2012 Year-Ahead Forecast Process with Due Date for Revisions		
Filing	**Due Date**	**Days before Year-Ahead RA Filing**
LSEs file Historical load info	15-Mar	230
LSEs file 2012 Year-Ahead Load Forecast	22-Apr	192
LSEs receive 2012 Year-Ahead RA obligations*	25-Jul	98
Final date to file revised forecasts for 2012	19-Aug	73
LSEs receive revised 2012 RA obligations*	15-Sep	46
LSEs receive RMR allocations	7-Oct	24
LSEs file Final 2012 Year-Ahead RA Filing*	31-Oct	0

* -- modified timeline

3.2.9. Current Customer Forecasting Methodology

D.04-10-035 directed LSEs to prepare forecasts of customer load migration using the "best estimate" approach. The "best estimate" approach requires LSEs to reasonably predict how much load the LSE will serve in the upcoming compliance year, taking into account possible gain or loss of customers. This is opposed to the "current customer" approach, which requires LSEs to simply forecast their current load and current customers forward into the next compliance year. This "best estimate" approach was affirmed in D.09-06-028. That decision left it open to staff to evaluate when and if this issue will be reopened for discussion, and encouraged staff to explore the administrative burden associated with implementing a current customer load forecasting method.

PG&E proposes using the "current customer" approach, as it has in previous years. PG&E asserts that this approach is what PG&E currently uses to develop its load forecasts in its regulatory filings at the Commission, such as the load forecast it uses in its Energy Resource Recovery Account forecast proceeding to develop its estimated costs of electric power procurement.[41]

AReM opposes PG&E's proposal to move from the "best estimate" method to "current customer" approach. AReM claims that PG&E fails to provide any evidence to substantiate its claim of gaming or that the benefits of moving to the "current customers" approach outweigh LSEs' costs of making the change.[42]

Discussion:

There is no compelling reason that the standard of forecasting for RA compliance needs to change. The "current customer" approach is counter to our recently adopted mechanism for Local RA reallocation, as the purpose of that reallocation is to gauge the effect on Local RA obligations for customers that the

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[41] PG&E Comments on Phase 2 proposals at 10.

[42] AReM Comments on Phase 2 proposals at 11.

LSE has not yet signed up. Whereas the previous Local RA True up approach used in 2010 was explicitly a "current customer" tally, the Local RA Reallocation approach is a "best estimate" forecast out several months. Further, the recent reopening of Direct Access means that there will be increased volatility in customer counts, as more customers can now move among different LSEs. Thus, it is not appropriate at this time for LSEs to require a forecast based on current customers.

3.2.10. Monthly/Seasonal Local Resource Adequacy Requirement

The Standard Capacity Product rules provide Scheduling Coordinators an opportunity to substitute non-RA resources for any RA unit to avoid being penalized for a deficiency. For Scheduling Coordinators in generation-constrained areas, there is no opportunity to make such a substitution since there are no available resources during off peak months. This is because all available local resources are already committed through the Annual Local RA obligation based on August forecasts.

SDG&E proposes a seasonal Local RA requirement. SDG&E argues that the operation of the Standard Capacity Product significantly alters the RA landscape for LSEs in generation constrained areas. SDG&E argues it has no opportunity to mitigate Standard Capacity Product penalties through procuring other local resources. To address this issue, SDG&E proposes to adopt two local RA requirements: (1) a peak seasonal requirement using forecasted August peak loads; and (2) a lower requirement for off-peak seasons and months using some representation of the forecasted loads for those seasons and months. SDG&E contends that in addition to providing a more precise representation of the CAISO's resource requirements during off-peak seasons and months, a lower, off-peak seasonal LCR would presumably free resources in generation-constrained areas to be substituted for resources on force outage.[43]

AReM supports SDG&E's proposal for monthly or seasonal Local RA requirements. TURN supports SDG&E's proposal in concept. However, in practice, TURN believes that SDG&E has misread the major barriers to implementation. TURN suggests instead that the Commission request a study of the potential for sub-annual Local RA Requirements solely for the SDG&E service territory, given that San Diego area's LCRs are uniquely significant in driving SDG&E's planning and procurement.[44]

The CAISO does not support SDG&E's proposal because "it incorrectly assumes that the change in methodology will reduce the local RA obligation in non-summer months, result in lower costs than the current year-ahead obligation, and not place a significant burden on the [CAISO]."[45] SCE opposes SDG&E's proposal, and shares the CAISO's concerns. PG&E also does not support SDG&E's proposal.

Dynegy supports allowing excess local capacity shown in an RA compliance filing to be used to substitute for local RA capacity on outage, but strongly opposes changing the annual local RA requirement to monthly or seasonal requirements.[46]

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[43] SDG&E Comments on Phase 2 Proposals at 3.

[44] TURN Comments on Phase 2 Proposals at 3-4.

[45] CAISO Comments on Phase 2 Proposals at 3.

[46] Dynegy Comments on Phase 2 Proposals at 15.

DRA supports an evaluation of the feasibility of a seasonal local RA requirement, at least in the San Diego areas.[47]

In reply comments, SDG&E requests that the CAISO provide parties with data to back up the claim that LCRs can be higher in off peak months. This data will allow parties to evaluate SDG&E's proposal fairly. "If the CAISO truly believed that seasonal maintenance created operational needs that exceeded those provided by the current annual obligation, then the CAISO, and this Commission, should be basing LCR procurement obligation using the higher LCR requirements for some month (or period) other than August."[48]

Discussion:

At this time, we do not have sufficient information to adopt a seasonal RA requirement. In D.10-06-036, we stated that we intended to work with CAISO and other stakeholders to discuss the seasonal RA issue raised by SDG&E and determine if these concerns can be accommodated. The CAISO has identified problems in calculation and study modeling that would need to be satisfied, such as loads and resources with outages in off-peak months. The CAISO spent a considerable amount of time reaching stakeholder support for the current LCR modeling requirements and methodologies. To do so again with a new study would be time consuming, in addition to actually doing the work of modeling. Were the CAISO or any other party to perform this study, a lengthy description of modeling work and methodology would need to be composed and vetted via

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[47] DRA Reply Comments on Phase 2 Proposals at 4.

[48] SDG&E Reply Comments on Phase 2 Proposals at 2.

stakeholders, concurrent with study results. If such a study is forthcoming, it can be considered in next year's RA proceeding.

3.2.11. Multi-year RA Contracts

IEP proposes that the Commission encourage multi-year RA contracts, since short-term contracts conflict with the goal of encouraging investment in generation infrastructure.

AReM opposes IEP's proposal to encourage multi-year RA contracts due to a lack of detail.

TURN is not sure what IEP is asking the Commission to do. However, TURN notes that LSEs and IOUs in particular already can - and often do - enter into multi-year RA contracts with independent generators.[49] PG&E claims that the majority of their contracted RA capacity comes from multi-year contracts. Additionally, PG&E and other utilities periodically hold multi-year solicitations for RA capacity.

Calpine supports IEP's proposal. Calpine argues that although new resources are procured through long term Requests for Offers, existing resources are limited to participating in shorter-term solicitations as well as spot markets for RA, energy, and ancillary services.[50] Calpine contends that existing generators need stable and adequate multi-year compensation to ensure the availability of their resources and to support cost-effective maintenance and upgrades, and the introduction of multi-year contracting requirements into the

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[49] TURN Comments on Phase 2 Proposals at 5.

[50] Calpine Comments on Phase 2 Proposals at 6.

current RA program might provide appropriate levels and predictability and compensation for existing generators.[51]

Discussion:

We find the proposal contains insufficient detail to adopt it, and therefore decline to do so.

3.2.12. Aggregation of "other PG&E" Local Areas

D.06-06-064 established an approach for aggregation of certain local areas for RA purposes in 2007 in order to address market power concerns. After determining each LSE's local RA obligation in each local area, using the CAISO LCR study, 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. These are known as the "other PG&E" local areas.

Every RA decision since D.06-06-064 (which established the RA program) has adopted this feature for each compliance year. Most recently, D.10-06-036 continued aggregation of the "other PG&E" local areas for the 2011 RA compliance year: "Given the 2011 LCR study results of the 'other PG&E' areas, there still are a limited amount of resources in those areas. At this time there is still a need to keep the 'other PG&E' areas aggregated for market power concerns."[52]

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[51] *Id*.

[52] D.10-06-036 at 18.

In its November 30, 2010 proposals, Energy Division proposed aggregation of the "other PG&E" local areas on a permanent basis. AReM supports Energy Division's proposal, as does PG&E.

Calpine does not support aggregating the "other PG&E" local areas on a permanent basis. Calpine argues that the continued aggregation of "PG&E other" local areas for compliance purposes allows LSEs, in aggregate, to avoid RA procurement of the resources that the CAISO needs for local reliability.[53]

Dynegy suggests that if "a conscious decision has been made to not address the capacity deficiencies in some local areas because doing so would be too expensive, then perhaps the Commission should consider waiving the local capacity requirements for LSEs in those particular areas rather than perpetuating the fiction that capacity in one locally constrained area somehow meets the reliability needs of a separate, electrically distant locally constrained area."[54]

Discussion:

We find that it is reasonable to permanently aggregate the "other PG&E" local areas for RA compliance purposes. The local area constraints in the "other PG&E" local areas have not changed since this aggregation was adopted, indicating market power mitigation is still needed. Parties have concerns that permanent aggregation will impede the creation of incentives to ameliorate deficiencies in certain Local Areas and subareas. However, there already is sufficient incentive to ameliorate subareas via transmission development, and a number of transmission improvements are currently under construction. These

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[53] Calpine Comments on Phase 2 Proposals at 3.

[54] Dynegy Comments on Phase 2 Proposals at 13.

transmission improvements will have very significant effects on the LCR obligations, number and size of subareas, and even on boundaries of local areas themselves. It is too early to decide whether there will be any deficiencies in the "other PG&E" local areas in the future. If so, we will revisit this question at that time.

3.2.13. Elimination of Preliminary Local RA Filing

D.06-06-064 at 48 adopted a preliminary Local RA filing to facilitate coordination of the Local RA program with the CAISO's Reliability Must Run (RMR) process: "We require that all LSEs file Preliminary Local [Resource Adequacy Requirement] RAR compliance showings on September 22, 2006. This preliminary Local RAR demonstration can be as much as the LSEs' full Local RAR demonstration, but, at a minimum, it must accurately show whether the LSE has, by September 22, 2006, entered into any contract with a unit that is among the list of units proposed for 2007 RMR Contracts. (footnotes omitted)"

Since 2006, the volume of RMR contracts has decreased substantially, dropping to only one existing contract (Oakland Power Plant) for approximately 165 MW in total. Each year on October 1, the CAISO decides whether to extend or terminate existing RMR contracts. Since 2006, the CAISO has considered information from LSE Preliminary Local RA Filings to make this decision.

Energy Division proposes eliminating the preliminary RA showing, as its usefulness has declined substantially. AReM supports Energy Division's proposal. CAISO does not object to it. PG&E and Calpine also support the proposal.

Discussion:

The process of going through the Preliminary Local RA Filing is an administrative cost to both the LSEs and energy agencies that need to fulfill this requirement and process the filings. Since there is now only one RMR contract, this administrative cost appears unwarranted. We adopt Energy Division's proposal. Starting in 2011, LSEs will not be required to file a Preliminary Local RA Filing. LSEs that contract with any resources with an existing RMR contract will still be required to inform the CAISO and Energy Division via email by the second Monday in September each year.

3.2.14. Elimination of the Use of Portfolio Resources

In the 2006 RA guide, Energy Division determined that the RA compliance process could accommodate the use of RA Portfolios. RA Portfolios are plant-specific RA contracts, as opposed to unit-specific RA contracts. For example, in a year-ahead compliance filing, an LSE may want to enter into an RA contract with a generator for a specified level of MW to be provided by any one of three units at one of its power plant, as opposed to a specific unit.

Currently, for purposes of the Year-Ahead compliance filings only, RA Portfolios are acceptable subject to the following conditions:

1. The portfolio must be eliminated and converted to specific units in the Monthly System RA showing.
2. Any portfolio must be unique and the units behind that portfolio must be specified, communicated to the CAISO/CPUC, and not allowed to change.
3. The portfolio may not have total capacity greater than the summed Qualifying Capacity of the individual units.
4. Portfolio may only be comprised of units served by the same busbar.

5. All units are located in the CAISO control area.[55]

D.06-07-031 adopted the use of portfolio resources for RA purposes and the 2006 RA guide and template. In order to implement this RA program rule, Energy Division staff created a resource tab in RA system template specifically for LSEs to show RA "Portfolio Resources."

Discussion:

We will eliminate the option for using portfolio resources as a part of RA compliance. Given that LSEs have only once used the process for submitting portfolio resources in their RA Filings, this modification should not cause any significant problems. Starting in 2012 compliance year, Energy Division is authorized to remove the Portfolio Resources tab of the compliance template and remove that section of the RA Guide. Portfolio resources as specified in the 2005 workshop report will no longer be accepted as RA capacity.

3.3. Resource Adequacy Rules for Demand Response

Currently, there are a number of ways that DR resources stand apart from conventional supply resources in terms of their ability to provide RA credit for LSEs. For example, conventional supply resources are required to be available a minimum of four hours a day and three days in a row. DR programs currently do not have this requirement. DR resources are not subject to many of the CAISO's RA availability rules. The CAISO does not dispatch DR resources directly with full consideration of all available resources in the market. This significantly reduces the value of DR resources even though they are counted for RA.

[55] 2006 RA Guide at 12.

In this proceeding, we consider the extent to which RA credit rules related to DR programs can be harmonized with RA credit rules related to conventional RA resources so DR resources can be integrated with the CAISO market and treated more similarly to conventional generation resources. The Scoping Ruling in this proceeding solicited proposals from parties regarding RA credit rule changes for DR programs to count as RA.[56] On November 30, 2010, parties submitted proposals and/or comments on some of these rule changes.

Under the current RA rules, DR credits are deducted from total RAR obligations each LSE receives[57] Each LSE is required to comply with the RAR by showing a portfolio of RA capacity contracts that fit into the four resource categories (i.e., Maximum Cumulative Capacity or MCC buckets) on a year-ahead and month-ahead basis.

As a part of the efforts to integrate DR resources with the wholesale market, the CAISO recently developed two DR products that it would dispatch: the Reliability Demand Response Product (RDRP) and the Proxy Demand Resource (PDR) product. The RDRP is for emergency DR only. The CAISO implemented the RDRP as a part of the settlement on emergency DR adopted in D.10-06-034.

The PDR product is one of the CAISO's three DR products currently available in the wholesale energy market, which also includes the RDRP and the Participating Load. The PDR product is an energy-only product (i.e., not a capacity product). The CAISO implemented the PDR product "in order to

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[56] See Phase 2 Scoping Ruling issued on November 3, 2010 at 4.

[57] See Energy Division's 2011 Filing Guide for System and Local Resource Adequacy Compliance Filing, Section 13 at 13.

increase DR participation in the [CA]ISO market and respond to stakeholders' requests for a DR product that will facilitate the participation of existing retail demand programs in the [CA]ISO market."[58]

The CAISO designed the RDRP to fit the IOUs current reliability-based DR programs. The RDRP is scheduled to be implemented by spring 2012.[59] The CAISO developed the PDR product pursuant to the FERC Order 719, which directed the CAISO to remove tariff impediments that may prevent retail electricity customers from bidding their DR capabilities directly into wholesale markets if the state or other local regulatory authority approved such bidding by retail customers under their jurisdiction. The PDR product was implemented on August 10, 2010 after the CAISO's proposal was conceptually approved by the Commission for use by its retail customers.

Energy Division also submitted proposals on two rule changes related to DR on November 30, 2010 and the third rule change through the ALJ ruling issued on January 10, 2011: 1) implementation of a cap on RA credit for reliability-based DR programs; 2) use of Back-up Generators for the PDR product that counts for RA; and 3) DR availability requirement. On January 18, 2011, Energy Division conducted a workshop to discuss the issues related to proposals by the parties' and staff. On February 8 and 22, 2010, parties filed comments and reply comments on the workshop issues.

We will consider certain issues below which are necessary to adopt at this time. Other DR issues related to RA will be considered at a later time.

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[58] See http://www.caiso.com/23bc/23bc873456980.html#27eac9af5ef0.

[59] See CAISO's Comments on Phase 2 Proposals filed on February 8, 2011 at 5.

3.3.1. Requirement for Demand Response Programs to be Available for Events a Minimum of Four Hours per Event and Three Consecutive Days

The current RA Qualifying Capacity counting rules for DR programs are separated into two categories, one for resources with maximum event lengths of up to two hours per event, and one for resources with maximum event lengths of over two hours per event. All currently funded utility DR programs are in this second category. The counting rules for all non-DR RA resources require that they must be available for a block of at least four consecutive hours on three consecutive days.

D.05-10-042, Ordering Paragraph 16, restated the minimum requirements for a resource to qualify for the RAR:

> The Commission's determination in D.04-10-035 that to qualify for RAR, a resource must (1) be able to operate for a minimum of four hours per day for three consecutive days and (2) be able to run a minimum aggregate number of hours per month based on the number of hours that loads in the CAISO control area exceed 90% of peak demand in that month is affirmed as to the summer months; for the non-summer months, the second prong of that test is waived.

D.09-08-027 required IOUs to file DR program applications for approval of DR activities and budgets for 2012-2014.[60] On August 27, 2010 an ALJ Ruling in the DR rulemaking proceeding (R.07-01-041) provided guidance for 2012-2014 DR applications. In this ruling, IOUs were encouraged "to propose (or maintain existing) program terms that would make 2012-2014 DR programs consistent

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[60] D.09-08-027, Ordering Paragraph 41.

with these RA availability requirements, to the extent that it is feasible to make DR programs available for four hours per event on three consecutive days."[61]

Consistent with this DR program guidance and with qualifying capacity counting rules for other resources, Energy Division staff proposes elimination of the current special DR specific requirements related to event length, and proposes requiring DR resources to be available at minimum four hours per event and three days in a row in order to count for RA credit.

CAISO supports the Energy Division proposal.[62] SDG&E supports Energy Division's proposal to bring DR resources in line with other RA resources by making the availability requirements the same. PG&E notes that all its programs already comply with this proposal.

EnerNOC does not oppose the proposed hours requirement. EnerNoc's concern is that the method for determining RA eligibility between retail and wholesale DR participation should be consistent, especially if retail programs are bid into the CAISO's PDR or RDRP products in order to prevent preferential treatment of utility DR programs. [63]

Discussion:

No party objects to a counting rule similar to that for conventional supply side resources that requires DR resources to be available for a block of at least four consecutive hours on three consecutive days. This modification provides

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[61] R.07-01-041 August 27, 2010 ALJ Ruling at 8, providing guidance for 2012-2014 Demand Response Applications.

[62] CAISO Comments on Phase 2 Issues at 2.

[63] EnerNOC Comments on Phase 2 Issues at 4.

consistency between DR and non-DR resources. We therefore adopt this rule change.

3.3.2. Implementation of the MW Cap on RA Credit for Reliability-based Demand Response Programs

D.10-06-034 adopted a Settlement Agreement between the CAISO, CLECA, DRA, EnerNoc, PG&E, SCE, SDG&E, and TURN (Settling Parties). As a part of the Settlement, the Settling Parties agreed to a "CPUC enforced annual limit designed to limit reliability-based DR program capacity to a specified percent of the CAISO's all-time coincident demand, which is currently 50,270 MW."[64] The annual RA credit caps (annual limits) plus a 10% "tolerance band[65]" applicable to the emergency-triggered DR programs (also referred as "reliability-based") are as follows:[66]

- In 2012, 3% of the CAISO's all-time coincident demand;
- In 2013, 2.5% of the CAISO's all-time coincident demand; and
- In 2014, 2% of the CAISO's all-time coincident demand.

Energy Division proposes to implement the Settlement adopted in D.10-06-034 for 2012 RA. Energy Division calculated the total amount of IOU reliability-based DR programs eligible to count for 2012 based on the methodology adopted in D.10-06-034.

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[64] D.10-06-034, Appendix A at 6 (Section C.1).

[65] The 10% tolerance band is applicable from 2012-2015. For 2016 and beyond, the tolerance band will be 0%. (See D.10-06-034, Appendix A at 7.)

[66] *See* D.10-06-034 at 12.

PG&E supports Energy Division's proposal, stating that it is important to incorporate the processes described in D.10-06-034 which limits the amount of emergency-triggered DR into the RA determination methodology.[67]

EnerNOC notes that the Commission did not address the method by which qualified third-party DR providers would receive an allocation of the RA eligible capacity. EnerNOC contends that this means the only option for participating in RDRP for third-party DR providers would be to go without RA-eligible capacity. Thus, EnerNOC argues that participation, on that basis, would be discriminatory against third-party DR providers, since the IOUs are currently the only providers of that product and are, therefore, allocated all the RA-eligible capacity.[68] EnerNOC proposes that on an annual basis the Commission determine the allocation amounts of RA eligible capacity based on the load share ratio of the RA eligible capacity determined in the settlement.

Discussion:

No party objects to the Energy Division proposal to implement the MW caps for reliability-based DR programs adopted in D.10-06-034. The Energy Division proposal is reasonable and we will adopt it. The RA amounts applicable to specified reliability-based DR programs in each IOU service territory shall be less than or equal to the following amounts:

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67 PG&E Comments on Phase 2 Issues at 6.

68 EnerNOC Comments on Phase 2 Issues at 5.

1. PG&E: 543.9 MW
2. SCE: 1,087.8 MW
3. SDG&E: 27.2 MW
4. Total: 1,658.9 MW

The above cap for each IOU applies only when the total load impacts from all three IOUs' reliability-based DR programs exceed 1,658.9 MW as shown above, pursuant to Section C.4.a. of the Settlement adopted in D.10-06-034.

EnerNOC raised a valid issue regarding the allocation of the cap within each IOU service territory (i.e. Transmission Access Charge area). Neither D.10-06-034 nor the settlement adopted by that decision explicitly addressed this issue. However, this issue is outside the scope of this proceeding. We will address this issue in the 2013 RA proceeding.

3.3.3. RA Counting for PG&E's Peak Day Pricing

In this proceeding, we will grant PG&E's request and allow exemption for 2012 for its Peak Day Pricing (PDP) from the current RA requirement that DR programs must operate between the hours of 1:00 p.m. to 6:00 p.m.

Pursuant to the Phase 1 decision of this proceeding, PG&E requests that its PDP be exempted for 2012 from the RA rule requirement that DR programs must operate between the hours of 1:00 p.m. to 6:00 p.m. PG&E proposes that PDP receives full DR credit for RA even though under PG&E's tariffs, it is only usable during the hours of 2:00 p.m. to 6:00 p.m. The Commission determined the PDP hours of operation from 2:00 p.m. - 6:00 p.m. in its last rate design proceeding.[69] PG&E's next rate design proceeding is scheduled for February 2012.

[69] D.10-02-032 at 32.

AReM rejects PG&E's proposal to get RA credit for its default electric tariff. AReM does not believe the PDP tariff is a DR program. AReM contends that while, the PDP program may encourage customers to reduce their power use when prices are high, it does not provide the CAISO with any locational dispatchability.[70]

DRA supports PG&E's proposal to allow PG&E an exception for the hours of its Peak Day Pricing in 2012.[71]

CAISO only supports counting DR resources for local RA if they are able to be dispatched by local area where they are needed. "Enabling retail DR programs, like PG&E PDP program, to make energy available wherever it is located on the grid when it is needed can exacerbate congestion management for the ISO and increase costs for consumers."[72]

Calpine opposes PG&E's proposal to give full RA credit to its PDP retail program in 2012. CLECA believes that PDP should be given RA credit for 80% of the load impact on a transitional basis.

SDG&E supports PG&E's request, pointing out that last year the Commission made an exception to avoid "undervaluing DR [demand response] programs that could not immediately adapt to new measurement hours."[73] SCE supports PG&E programs being able to count these programs for full RA credit until the programs can be modified to meet the new time requirements.

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[70] AReM Comments on Phase 2 Issues at 9.

[71] DRA Comments on Phase 2 Issues at 7.

[72] CAISO Comments on Phase 2 Issues at 8.

[73] SDG&E Comments on Phase 2 Issues at 11.

Discussion:

The Phase 1 decision in this proceeding changed the summer DR measurement hours effective in 2012 to 1:00 p.m. to 6:00 p.m. but allowed DR program operators to request exemptions. D.10-06-036 at 44 states:

> To ease the transition to the new measurement hours, DR program operators may request that specific DR programs continue to be measured using the existing hours (2 p.m. to 6 p.m.) during 2012, or potentially future years, if they have a fixed operational period set by a Commission decision. In order for DR program operators to request use of the 2 p.m. to 6 p.m. measurement hours, the operator shall file a proposal to do so in Phase 2 of this proceeding that identifies, at a minimum, the specific program(s), it's (their) operational period(s), a specific citation from a Commission decision setting this operational period, and when the operational period may be changed. To be clear, we anticipate that most or all DR programs that will be evaluated in the 2012-2014 DR program applications will not use this process. *Only those programs whose operational periods cannot be changed in those applications or another venue in time for 2012 implementation (for instance due to previously adopted rate design) should use this process.* (Emphasis added.)

The Phase 1 decision set clear criteria for exemption, which the Commission allows only these programs with operational period that can not be changed in time for 2012 RA.

PG&E's PDP schedules were adopted in D.10-02-032 for commercial and industrial, agricultural and residential customers. Large commercial and industrial customers with demand greater than 200 kW have been defaulted to PDP in May 2010 and large agricultural customers in February 2011. PDP schedules for other customers are uncertain pending a decision on PG&E's Petition for Modification of D.10-02-032.[74]

PG&E's PDP is the subject of one of the following rate design proceedings: Phase 2 of the General Rate Case (GRC) or Rate Design Window. PG&E's next Rate Design Window proceeding is not until February 2012.[75] Therefore, it is reasonable to grant PG&E's request for exemption for 2012 RA because we cannot address the rate design change for its PDP in time for 2012 RA.

We will require PG&E to propose changes to the current large commercial and industrial and agricultural customers PDP operational period of 2 p.m. – 6 p.m. to 1 p.m. - to 6 p.m. in its 2012 Rate Design Window application. PDP for other customer classes that has not been implemented should comply with the new measurement hours in 2013.

We will deny PG&E's request[76] to defer this requirement to its 2014 GRC application because the longer the wait, the harder it will be for customers to adopt the change.

In its comments on the Proposed Decision, SCE requests that the Commission extend the exemption granted to PG&E to all LSE for 2012.[77] For the first time in this phase of the proceeding, SCE notes that it has similar programs that should be granted equivalent treatment. Its Critical Peak Pricing (CPP) and Peak Time Rebate (PTR) programs operate in the summer from 2 p.m. to 6 p.m., rather than the 1 p.m. to 6 p.m. as required by D.10-06-036 necessary to

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[74] See PG&E's 2012-2014 demand response testimony at 2-32 to 2-34.

[75] See Ordering Paragraph 26 in D.10-02-032.

[76] PG&E comments on the Proposed Decision at 2.

[77] SCE comments on the Proposed Decision at 5.

receive full RA credit. These hours were first adopted in D.09-08-028. SCE recently filed its 2011 GRC application on rate design issues and did not propose any changes to these hours.[78]

As discussed earlier, D.10-06-036 allowed the IOUs to request exemptions for the DR programs with operational periods that cannot be changed in time for 2012. That decision specifically requires the IOUs to submit such requests in this proceeding. In its comments on the Proposed Decision, SCE provided no explanations as to why it did not submit any request an exemption for its CPP and PTR programs; PG&E's identical request was added to the scope of this proceeding. Furthermore, SCE did not propose to change the current operational hours to 1 p.m. to 6 p.m. for these two programs in its current GRC application, which was filed on June 6, 2011 (well after D.10-06-036). Therefore, as SCE did not follow the clear process laid out for this matter, we will deny SCE's request.

4. 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 on June 13, 2011. Reply Comments were filed on June 20, 2011.

Based upon comments to the proposed decision, the following modifications have been made:

- Clarify language concerning penalties for RA program violations, generally as suggested by DRA. The time period for increased

[78] A.11-06-007.

penalties for repeat violations is now consistently a "compliance year";

- Modification of Finding of Fact 32, related to the DR resources, suggested by PG&E;
- Addition of language related to the replacement rule, seeking further quantification of costs incurred by the CAISO and LSEs;
- Denial of SCE's request made in comments to the Proposed Decision to provide it with an exemption for RA treatment of two DR programs;
- Clarification of DR program totals allocated toward RA credit, consistent with the Settlement in D.10-06-034; and
- The LSE replacement rule is maintained for the 2012 RA compliance year.

5. Assignment of Proceeding

Mark J. Ferron is the assigned Commissioner and David M. Gamson is the assigned ALJ in this proceeding.

Findings of Fact

1. The assumptions, processes, and criteria used for the 2012 LCR study were discussed and recommended in a CAISO stakeholder meeting, and they generally mirror those used in the 2007 through 2011 LCR studies.

2. In previous RA decisions, the Commission delegated ministerial aspects of program administration to the Energy Division.

3. A coincident factor is used in determining RA obligations by adjusting individual LSE peak forecasts for the fact that each LSE may or may not peak at the time of the CAISO coincident peak. D.05-10-042 adopted an average coincident adjustment factor methodology which uses historical coincident factors and the same coincident adjustment factor for all.

4. The rationale in D.05-12-042 for simplicity in adopting an average coincident factor for determining LSE RA requirements is no longer valid. The CEC currently uses two coincidence factors for purposes related to RA requirements; harmonizing these two factors would promote the goal of simplicity.

5. An average coincidence factor across all customer classes hides certain cost differences among classes and LSEs. In essence, this method serves as a cross subsidy from industrial and commercial customers to residential customers.

6. Because current Direct Access rules provide limited opportunities for customers to migrate between IOUs and ESPs, it is unlikely that a more accurate reflection of cost drivers stemming from the use of unbundled coincidence factors for different LSEs would significantly increase the incentive for some customers to migrate from IOUs to ESPs.

7. There is significant technical analysis which remains to be produced before the coincidence factor can be unbundled among LSEs for use in determining RA requirements.

8. The Standard Capacity Product is a system of availability metrics and performance penalties that RA resources face if they are subject to forced outages at rates above the overall fleet average.

9. D.09-06-028 deferred action on mandating the Standard Capacity Product for RA compliance for resources whose Qualifying Capacity was based on historical data, and for DR resources.

10. There remains considerable uncertainty as to how to apply the Standard Capacity Product for RA compliance for DR resources.

11. D.10-06-036 altered the RA net qualifying capacity rules to accommodate the Standard Capacity Product performance and availability provisions that are

now accepted by FERC and in effect. The net qualifying capacity rules were modified in such as way as to remove a "double penalty" problem which was a barrier to implementation.

12. Violations of RA requirements in Commission decisions are subject to Commission-imposed penalties for procurement deficiencies, late filing, or other reasons.

13. D.10-06-036 adopted a revised penalty structure for violations of RA requirements. That decision contained penalties for deficiencies that are remedied within five business days.

14. The current penalty structure for violations of RA requirements can penalize LSEs for mistakes identified by agency staff soon after filings are submitted each month.

15. D.06-07-031 adopted a protocol for counting of units for RA purposes that take scheduled outages during the RA compliance year, for the purpose of determining resource availability.

16. The Commission's RA policy includes a "LSE-replace" rule whereby LSEs are only able to count generating units that are not impacted by scheduled outages towards meeting their RA obligations.

17. The current LSE-based replacement obligation for RA capacity for scheduled outages stands in the way of the making the Standard Capacity Product a commercially viable product.

18. SCE's proposed Planned Outage Adder essentially increases the Planning Reserve Margin by requiring all LSEs to contract for additional RA capacity regardless of the CAISO's need for it and whether RA units actually go on outage.

19. SCE's Planned Outage Adder proposal is less consistent with Commission goals of cost causation and cost minimization than the current scheduled outage requirement.

20. It is unclear what value the current scheduled outage rule provides in terms of reliability risk avoided by the rule. In addition, there is a significant administrative effort that goes into implementing the current rule.

21. There is no viable alternative to the LSE replace rule at this time.

22. In recent years, the median price paid for RA capacity, both system and Local, has been well below the RA waiver trigger price level.

23. The RA waiver trigger had been applied for only three times (and granted twice) since the 2007 compliance year. This fact shows that LSEs do not appear to be subject to market power in such a way as to make compliance with RA obligations impossible.

24. The Commission adopted the current Path 26 allocation in D.07-06-029, whereby the CAISO allocates a portion of the transfer capability on the path to LSEs based on proportionate share of their peak demand. The current process allocates the benefits on Path 26 to all LSEs.

25. D.05-01-042 adopted an informal process for LSEs to dispute and revise their year-ahead RA forecasts, but did not set clear timelines on the process.

26. It is becoming increasingly important for LSEs to have the opportunity to revise RA forecasts, due to greater level of uncertainty regarding future loads and customer retention.

27. The "best estimate" approach to forecasts of customer load migration adopted by D.04-10-035 requires LSEs to reasonably predict how much load they will serve in the upcoming compliance year, taking into account possible gain or loss of customers.

28. The Standard Capacity Product rules provide Scheduling Coordinators an opportunity to substitute non-RA resources for any RA unit to avoid being penalized for a deficiency. For Scheduling Coordinators in generation-constrained areas, there is no opportunity to make such a substitution since there are no available resources during off peak months because all available local resources are already committed through the Annual local RA obligation based on August forecasts.

29. The CAISO has identified problems in calculation and study modeling that would need to be satisfied to allow for determination of seasonal RA requirements. Identifying seasonal RA requirements would require a new time-consuming study.

30. D.10-06-036 continued aggregation of the "other PG&E" Local RA areas for the 2011 RA compliance year, due to market power concerns. This aggregation approach has been adopted yearly since 2006.

31. The preliminary local RA filing required by D.06-06-064 to facilitate coordination of the Local RA program with the CAISO's RMR process is an administrative cost to both LSEs and energy agencies that need to fulfill this requirement and process the filings. There is now only one RMR contract which would trigger this filing.

32. The 2006 Resource Adequacy guide allows the use of RA Portfolios for RA compliance purposes. RA Portfolios are plant-specific RA contracts, as opposed to unit-specific RA contracts. Since 2006, LSEs have only once used the process for submitting portfolio resources in their RA Filings.

33. Currently, there are a number of ways that DR resources differ from other supply resources in their ability to provide RA credit for LSEs.

34. All utility DR programs follow an RA Qualifying Capacity counting rule for resources with maximum event lengths of over two hours per call. The counting rules for all non-DR RA resources require that they must be available for a block of at least four consecutive hours on three consecutive days.

35. D.10-06-034 adopted a Settlement Agreement whereby the Settling Parties agreed to a Commission enforced annual limit designed to limit reliability-based DR program capacity to a specified percent of the CAISO's all-time coincident demand, which is currently 50,270 MW. In the settlement, there are annual RA credit caps plus a 10% tolerance band applicable to the emergency-triggered (also known as reliability-based) DR programs.

36. The total amount of IOU reliability-based DR programs eligible to count for 2012 is 1,658.9 MW. The reliability-based DR Programs subject to the caps are the IOUs' Base Interruptible Program, Summer Discount Plan, and Agricultural Pumping Interruptible Program.

37. Since the issuance of D.10-06-036, the CAISO developed the PDR program, which is a wholesale DR product.

38. D.10-06-036 changed the DR measurement hours effective in 2012 to 1:00 p.m. to 6:00 p.m. but allowed DR program operators to request exemptions. PG&E's PDP DR program operates from 2:00 p.m. to 6:00 p.m.

39. The next opportunity to change PG&E's current PDP is through its 2012 Rate Design Window application, which PG&E is required to file in February 2012.

Conclusions of Law

1. The CAISO's 2012 Local Capacity Technical Analysis Final Report and Study Results, dated April 29, 2011, should be approved as the basis for

establishing local procurement obligations for 2012 applicable to Commission-jurisdictional LSEs.

2. 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.

3. As in previous years, Energy Division should implement the local RA program for 2012 in accordance with the adopted policies in this and previous decisions.

4. Increased transparency and accurate cost information are Commission objectives in the RA program.

5. The average coincidence factor uses in determining RA requirements should not be unbundled among LSEs at this time, pending further study.

6. Due to recent actions of the FERC and the CAISO, it is now timely for the Commission to act to mandate the Standard Capacity Product for RA compliance for resources whose Qualifying Capacity was based on historical data.

7. It is reasonable to mandate the use of Standard Capacity Product penalties and availability metrics in RA contracts going forward, except for RA contracts involving DR programs.

8. It is reasonable to eliminate the current penalty for RA compliance deficiencies remedied within five days from the date of Energy Division notification in favor of a specific dollar penalty per instance without a daily multiplier.

9. In order to prevent LSEs from manipulating the RA compliance penalty structure and to deter intentional errors, after the second deficiency in any compliance year found by Energy Division and cured within five business days, LSEs should incur double penalties.

10. SCE's Planned Outage Adder method should not be adopted.

11. The current LSE-replace rule should be eliminated for the 2013 RA compliance year.

12. The RA trigger waiver price should not be changed at this time.

13. The Path 26 allocation process should not be changed at this time.

14. It is appropriate to provide added flexibility for LSEs to adjust their RA forecast.

15. There is no compelling reason that the "best estimate" standard of forecasting for RA compliance needs to change.

16. It is not reasonable to adopt seasonal RA requirements without a new CAISO study on this topic.

17. It is reasonable to permanently aggregate the "other PG&E" local areas for RA compliance purposes because the local area constraints in the "other PG&E" local areas have not changed since this aggregation was adopted, indicating market power mitigation is still needed.

18. The administrative costs associated with filing a Preliminary Local RA filing are unwarranted.

19. The option for using portfolio resources as a part of RA compliance should be eliminated.

20. To the extent possible, RA credit rules related to DR programs should be harmonized with RA credit rules related to conventional RA resources so DR resources can be integrated with the CAISO market.

21. It is reasonable to require that DR RA resources must be available for a block of at least four consecutive hours on three consecutive days in order to receive RA credit.

22. The Settlement Agreement adopted in D.10-06-034 should be implemented in this proceeding to adopt an enforced annual limit on reliability-based DR program capacity based on a specified percent of the CAISO's all-time coincident demand.

23. For the 2012 RA program, it is reasonable to allow PG&E an exemption from the requirement that its DR program operate from 2:00 p.m. to 6:00 p.m.

24. SCE did not make a timely request for an exemption from the requirement that its DR programs operate from 2:00 p.m. to 6:00 p.m. for 2012 RA purposes.

O R D E R

IT IS ORDERED that:

1. The California Independent System Operator's 2012 Local Capacity Technical Analysis Final Report and Study Results, dated April 29, 2011, is adopted as the basis for establishing local procurement obligations for 2012 applicable to Commission-jurisdictional load-serving entities as defined by Public Utilities Code Section 380, including but not limited to those entities listed in Appendix A to this decision.

2. The "Option 2/Category C" Local Capacity Requirements set forth in the California Independent System Operator's 2012 Local Capacity Technical Analysis Final Report and Study Results, dated April 29, 2011, 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. The Local Capacity Requirements for 2012 are as follows:

	2012 Local Capacity Requirements Needs		
Local Area Name	**Existing Capacity Needed**	**Deficiency**	**Total (Megawatts)**
Humboldt	190	22	**212**
North Coast / North Bay	613	0	**613**
Sierra	1685	289	**1974**
Stockton	389	178	**567**
Greater Bay	4278	0	**4278**
Greater Fresno	1899	8	**1907**
Kern	297	28	**325**
Los Angeles Basin	10865	0	**10865**
Big Creek/ Ventura	3093	0	**3093**
San Diego	2849	95	**2944**
Total	**26158**	**620**	**26778**

3. 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, D.08-06-031, D.09-06-028, and D.10-06-036 for compliance years 2008, 2009, 2010 and 2011, respectively, are continued in effect for compliance year 2012, subject to the modifications, refinements, and local capacity requirements adopted in the ordering paragraphs in this decision.

4. The Standard Capacity Product adopted in Decision 09-06-028 shall be a mandatory part of the Resource Adequacy compliance program for all Load Serving Entities (as defined by Public Utilities Code Section 380).

5. The penalties for Resource Adequacy program violations set forth in Decision 10-06-036, Ordering Paragraph 6(g) are modified to eliminate penalties for deficiencies remedied within five business days after notification from Energy Division with the application of a specified violation for deficiencies

added to Resolution E-4195. For deficiencies not remedied within five business days, penalties shall be as follows:

	System Procurement Deficiency	Local Procurement Deficiency
Deficiency remedied after five business days from the date of Energy Division notification or not remedied at all	$6.66/kilowatt-month	$3.33/kilowatt-month

6. As shown in Appendix B to this decision, Appendix A to Resolution E-4195 is modified to incorporate the creation of a new Specified Violation for Load Serving Entities (as defined by Public Utilities Code Section 380) that remedy deficiencies within five business days after notification by Energy Division staff. This new Specified Violation replaces in total the current Specified Violation for Small Procurement Deficiencies. Other Specified Violations from Appendix A to Resolution E-4195 will remain and continue to be used. The new Specified Violation shall be as follows:

Specified Violation	**Deficiency in either System or Local Resource Adequacy Filing**
Deficiency cured within five business days from the date of notification by Energy Division	$5,000 per incident if the deficiency is 10 Megawatts (MW) or smaller, or $10,000 for a deficiency larger than 10 MW. For the second and each subsequent deficiency in any calendar year, penalties will be $10,000 per incident if the deficiency is 10 MW or smaller, or $20,000 for a deficiency larger than 10 MW.

7. For the 2012 Resource Adequacy compliance year only, Load Serving Entities (as defined in Public Utilities Code Section 380) shall continue to use the scheduled outage rules adopted in Decision 06-07-031. Beginning in the 2013

Resource Adequacy compliance year, the "LSE-replace" rule of the scheduled outage rules is eliminated.

8. The schedule for all Load Serving Entities (LSEs) (as defined in Public Utilities Code Section 380) to file year-ahead Resource Adequacy (RA) forecasts and revisions shall be as follows for 2012, subject to the modification by the Assigned Commissioner or assigned Administrative Law Judge:

Filing	Due Date	Days before Year-Ahead RA Filing
LSEs file Historical load info	15-Mar	230
LSEs file 2012 Year-Ahead Load Forecast	22-Apr	192
LSEs receive 2012 Year-Ahead RA obligations	25-Ju	98
Final date to file revised forecasts for 2012	19-Aug	73
LSEs receive revised 2012 RA obligations	15-Sep	46
LSEs receive RMR allocations	7-Oct	24
LSEs file Final 2012 Year-Ahead RA Filing	31-Oct	0

9. The determination in Decision 10-06-036 that the Humboldt, North Coast/North Bay, Sierra, Stockton, Greater Fresno, and Kern local areas within the Pacific Gas and Electric Company (PG&E) territory (known as "other PG&E" local areas) were aggregated for Resource Adequacy compliance purposes for 2011, is made permanent for 2012 onward.

10. Load Serving Entities (LSEs) (as defined in Public Utilities Code Section 380) are not required to file a Preliminary Local Resource Adequacy

Filing. However, LSEs that contract with any resources with an existing Reliability Must Run Contract must inform the California Independent System Operator and the Commission's Energy Division via email by the second Monday in September of each year.

11. Load Serving Entities (as defined in Public Utilities Code Section 380) are no longer permitted to use Portfolio Resources as Resource Adequacy capacity, as previously authorized in Decision 06-07-031.

12. The following language from Ordering Paragraph 16 in Decision 05-10-042 shall apply to all demand response resources in the Resource Adequacy program: "to qualify for [resource adequacy requirements], a resource must (1) be able to operate for a minimum of four hours per day for three consecutive days …"

13. For the 2012, Resource Adequacy compliance year, demand response program totals allocated towards Resource Adequacy credit for the Base Interruptible Program, the Summer Discount Plan, and the Agricultural Pumping Interruptible Program shall be less than or equal to 543.9 Megawatts for Pacific Gas and Electric Company; 1087.8 Megawatts for Southern California Edison Company; and 27.2 Megawatts for San Diego Gas & Electric Company, if the three utilities' total load impact from these programs exceeds the aggregated cap of 1,658.9 Megawatts.

14. For the 2012 Resource Adequacy compliance year only, Pacific Gas and Electric Company's (PG&E's) Peak Day Pricing (PDP) program is granted an exemption from the requirement in Decision 10-06-036 that demand response programs must operate from 1:00 p.m. to 6:00 p.m. in order to receive full Resource Adequacy credit, so that in 2012, PG&E's PDP which operates from 2:00 p.m. to 6:00 p.m. shall receive full Resource Adequacy credit for these hours.

15. Rulemaking 09-10-032 shall remain open.

This order is effective today.

Dated June 23, 2011, at San Francisco, California.

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
CATHERINE J.K. SANDOVAL
MARK J. FERRON
Commissioners

I abstain.

/s/ MICHEL PETER FLORIO
Commissioner