STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION

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TO PARTIES OF RECORD IN RULEMAKING 09-10-032

This is the proposed decision of Administrative Law Judge (ALJ) David Gamson. It will not appear on the Commission's agenda sooner than 30 days from the date it is mailed. The Commission may act then, or it may postpone action until later.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 15 pages.

Comments must be filed pursuant to Rule 1.13 either electronically or in hard copy. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic and hard copies of comments should be sent to ALJ Gamson at dmg@cpuc.ca.gov and the assigned Commissioner. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ KAREN V. CLOPTON

Karen V. Clopton, Chief

Administrative Law Judge

KVC:jyc

Attachment

Decision **PROPOSED DECISION OF ALJ GAMSON** (Mailed 5/25/2010)

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 2011 AND FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM

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DECISION ADOPTING LOCAL PROCUREMENT OBLIGATIONS FOR 2011 AND FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM

1. Summary

This decision establishes local capacity procurement obligations for 2011 applicable to Commission-jurisdictional electric load-serving entities. These procurement obligations are based on an annual study of local capacity requirements performed by the California Independent System Operator for 2011. For the first time in three years, the total local capacity requirements determined by the California Independent System Operator for all local areas combined increased slightly from the prior year; the increase is from 27,727 megawatts in 2010 to 28,058 megawatts in 2011.

In addition, this decision adopts several proposed resource adequacy (RA) program refinements. A Qualifying Capacity Methodology Manual is adopted to provide load-serving entities with clear direction for procuring RA resources. The penalty for failure to timely procure adequate capacity is modified. Finally, several issues are deferred to later portions of this proceeding, including a RA local true-up mechanism.

2. Procedural Background

The Commission's Resource Adequacy program and requirements apply to all load-serving entities (LSEs) under our jurisdiction. Certain small or multi-jurisdictional LSEs are subject to different Resource Adequacy 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.

The *Assigned Commissioner's Ruling and Scoping Memo* (Scoping Memo), issued on December 23, 2009, identified the issues to be considered in Phase 1 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) 2011 local capacity requirements (LCR) study as well as this Commission's establishment of local procurement obligations for 2011 based on the LCR study. The second category, program refinement issues, pertains to various proposals to modify the RA program.

The Commission's Energy Division facilitated workshops on RA program refinement issues on December 14, 2009 and on January 27, 2010. In connection with the December workshops, parties were permitted to file workshop proposals on January 11, 2010. The Energy Division issued a workshop report on February 18, 2010. Comments on the Phase 1 issues discussed in the workshops were filed on March 12, 2010 by Alliance for Retail Energy Markets (AReM); Calpine Corporation; CAISO; California Wind Energy Association, California Wind Energy Association and the California Cogeneration Council (CalWEA/CCC); 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); EnerNOC, Inc. (EnerNOC); Independent Energy Producers Association; J.P. Morgan Ventures Enerty Corporation and BE CA LLC (J.P. Morgan); Mirant California, LLC and Mirant Delta, LLC (Mirant); Pacific Gas and Electric Company (PG&E); Southern California Edison Company (SCE); San Diego Gas & Electric Company (SDG&E); The Utility Reform Network (TURN) and the Western Power Trading Forum

(WPTF). AReM; CAISO; CAC; CalWEA/CCC; Calpine Corporation; DRA; Dynegy; EnerNOC, Inc.; North America Power Partners (NAPP); PG&E; SCE; SDG&E; and TURN filed replies on March 26, 2010. Sempra Energy Solutions (SES) and TURN also filed joint comments and reply comments.

Following a stakeholder process that began in 2008, on April 30, 2010, the CAISO posted its "2011 Local Capacity Technical Analysis, Final Report and Study Results" (2011 LCR Study) on its website, served notice of the report's availability, and filed it with the Commission on May 3, 2010. 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 10 and May 17, 2010, respectively. AReM and SDG&E filed comments regarding the LCR study and the establishment of local procurement obligations for 2011. Replies were filed by SCE and PG&E on May 17, 2010.

3. Local RA for 2011

3.1. 2011 LCR Study

Decision (D.)06-06-064 determined that a study of local capacity requirements performed by the CAISO would form the basis for this Commission's local RA program. The CAISO conducts its LCR study annually, and this Commission resets local procurement obligations each year based on the CAISO's LCR determinations. As noted above, the CAISO issued its final LCR report and study results for 2011 on May 3, 2010.

The CAISO states that the assumptions, processes, and criteria used for the 2011 LCR study were discussed and recommended in a stakeholder meeting held on November 24, 2009, and that, on balance, they mirror those used in the 2007 through 2010 LCR studies. The CAISO identified and studied capacity needs for the same 10 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 three years adopted Option 2 as recommended by the CAISO for 2008 through 2010 local procurement obligations. There is no evidence or recommendation before us suggesting that assumption of the reduced reliability associated with Option 1 is reasonable for 2010. We therefore affirm the continued application of Option 2 to establish local procurement obligations for 2011.

The 2010 and 2011 summary tables in the 2011 LCR report, copied below, show that for all ten areas combined, the total LCR associated with reliability Category C increased from 27,727 megawatts (MW) in 2010 to 28,058 MW in 2011. The existing capacity needed increased from 27,075 MW in 2010 to 27,094 MW in 2011. LCR needs decreased in the North Coast/North Bay, Sierra, Fresno, Big Creek/Ventura and San Diego Areas due to downward trends for load. LCR needs increased slightly in the Humboldt area due to new Humboldt Bay Power Plant configuration, in the Greater Bay due to the Portrero Power Plant retirement, in Kern due to load growth and in the Los Angeles (LA) Basin due to load growth and permanent retirement of the Antelope-Mesa Cal 230 kilovolt (kV) line. The Stockton area LCR needs are steady.

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**

2010 Local Capacity Requirements

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

Total	**8816**	**25822**	**34638**	**25321**	**102**	**25423**	**27075**	**652**	**27727**

The comments reveal no disagreement with CAISO's LCR determinations for 2011. As we noted in D.09-06-028, 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 2011 LCR study should be approved as the basis for establishing local procurement obligations for 2011 applicable to Commission-jurisdictional LSEs.

AReM notes that since the CAISO issued the first LCR calculation in September 2005, LCRs have increased by about 20% for the CAISO grid statewide. The number of deficient areas has also increased significantly. AReM points out that for 2011, only three LCRs are not deficient: North Coast/North Bay, LA Basin and Big Creek/Ventura. Even accounting for the addition of the Big Creek/Ventura Local Capacity Area (LCA) in the 2008 compliance year, which added 3,700 MW to the LCRs, AReM asserts that the trend is, at best, steady state. Further, while California is experiencing a major recession beginning in 2008, AReM shows that the LCRs are still increasing, by 1.2% from 2010 to 2011. AReM requests that the Commission consider improvements to the annual LCR process in Phase 2 with the objective to reverse this trend and begin to reduce the MWs of LCRs and number of LCAs when cost-effective, therefore, lowering costs for California's consumers.

SDG&E contends the South Bay power plant is not needed to satisfy local capacity requirements in the San Diego area in 2011 and that South Bay retirement will also advance important environmental goals. SDG&E claims that retiring a resource like South Bay, which SDG&E claims is both environmentally harmful and not necessary for reliability purposes in light of the CAISO's 2011 LCR study, would further California's important water resource goals. SDG&E

also argues that CAISO should undertake a separate, additional LCR study to determine seasonal local capacity obligations.

We intend to work with CAISO and other stakeholders to discuss the issues raised by AReM and SDG&E and determine if these concerns can be accommodated. The Administrative Law Judge (ALJ) will determine if these issues should be added to the scope of the proceeding in Phase 2.

3.2. Local Procurement Obligations for 2011

3.2.1. Continuation of the Local RA Program

The RA program was first implemented with the 2006 compliance year for "system" RA requirements. "Local" RA procurement obligations were first implemented the following year. Even though several decisions over the past five years have largely 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 [local capacity requirements (LCRs)] based on the [California Independent System Operator's (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 and D.09-06-028 established local procurement obligations for 2008, 2009 and 2010, respectively. We intend that local

RA program and associated regulatory requirements adopted in those decisions shall be continued in effect for 2011, subject to the 2011 LCRs and procurement obligations adopted by this decision.

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

3.2.2. Local Resource Adequacy True-ups

The resource adequacy program developed by the Commission provides local resource adequacy obligations for LSEs for a 12-month compliance period. However, the program currently does not require LSEs to true-up their obligations within the compliance year. It is possible that true-ups could be required for changes in load within the compliance year for various reasons; in particular, the re-opening of direct access in 2010 (discussed below) makes it more likely that some LSEs will have significantly different levels of load at times throughout the compliance year. One concern is that the result of not having a local true-up mechanism is that the local resource adequacy product loses its premium value after the year-ahead showing, creating financial risks for LSEs which lose customers and a possible competitive edge for new entrants.

Under the current practice, each LSE is obligated to meet its local resource adequacy requirement (RAR) annually by procuring local RA capacity based on its load ratio share. The load ratio share is the LSE's annual forecasted coincident peak load, adjusted by the California Energy Commission (CEC), divided by the total forecasted coincident peak load in the LSE's utility service territory. This method requires an LSE to procure the same amount of local RA capacity for every month of the forecast year, based on the peak month (August) local requirement. Until recently, there has been no process for adjusting an LSE's local RA obligation to account for or true-up load migration during the compliance period.

Adopting a local true up mechanism into the RA program was discussed in R.08-01-025, the predecessor to this Rulemaking. However, the Commission did not adopt a proposed local true up mechanism but instead deferred implementation to the 2011 compliance year and this proceeding.

Pursuant to Senate Bill (SB) 695 (Stats. 2009, ch. 337), the Commission reopened Direct Access (DA) in D.10-03-022. The decision states: "Effective April 11, 2010, all qualifying customers will be eligible to take DA service, up to the new maximum cap subject to the conditions as set forth herein. The increased DA allowances shall be phased in over a four-year period, subject to annual caps in the maximum DA increase allowed each year."[1] Additionally, D.10-03-022 states: "SB 695 requires the Commission to ensure that other providers of electricity in California are subject to the same procurement-related requirements that apply to the IOUs, including RARs, renewables portfolio standards, and greenhouse gas emission reductions."[2]

With the reopening of Direct Access, the expected load migration between LSEs throughout the year will have some effect on the local obligation of the participating LSEs. In order to track the local RA obligation and ensure that that

[1] D.10-03-022 at 2.

[2] D.10-03-022 at 25.

all service providers are subject to the same RA treatment, D.10-03-022 adopted a local true-up mechanism for 2010.[3] This mechanism applies for 2010 only.

SCE notes that D.10-03-022 allows for local attributes unbundling as part of the partial reopening of DA. SCE believes that the administratively determined price established in this decision is "appropriate for the initial partial reopening of direct access, and will serve to smooth the transition period for the market"[4] SCE notes that this established price should not be maintained and the market should be allowed to establish the most efficient outcome.

Calpine suggests that the transfer payment adopted in D.10-03-022 not be a part of the rules adopted for the 2011 RA compliance period. In particular, Calpine requests that the option to meet local RA obligations through a $24/kilowatt (kW)-year administrative transfer payment not continue beyond 2010. Calpine objects to this transfer payment because it is unclear that the amount represents an appropriate value for RA in all local locations.

As we just recently adopted the local RA true-up for 2010 and there is no compelling reason to change it at this time, we will continue the local RA true-up method adopted in D.10-03-022 for the rest of 2010 without revision. For 2011 and beyond, parties have proposed different local true-up methods. These are discussed below.

3.2.2.1. The "True-Up Approach" and "Reallocation Method" Proposals

SES and TURN filed separate local true-up proposals that have been revised into one and refined though the course of this proceeding. The initial

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[3] D.10-03-022 Appendix 3.

[4] SCE comments at 16.

proposal will be called the "True-Up Approach." The True-Up Approach is based on transferring specific shares of local requirements on individual customers using that customer's local-to-peak ratio and coincident peak demand.

The SES/TURN True-Up Approach uses a Local-to-Peak Ratio (LPR) percentage approach which is also the adopted method in the recent DA decision, D.10-03-022. Like the 2010 local true up adopted in D.10-03-022, the LPRs would be calculated by the Energy Division.

The next step is to calculate the Customer Local Obligation (CLO) associated with each migrating customer. As customers migrate, the load-losing LSE would calculate the CLO associated with the migrating customer and report it to the CEC and Energy Division. The Energy Division would then match the load migration between the losing and gaining LSEs and then require the load-gaining LSE to procure additional local RA capacity. The process would happen only once a year beginning in early February.

To address the issue of materiality, SES and TURN would limit the size of the load migration to 5 MW blocks of capacity. Additionally, to handle local RA capacity liquidity concerns, they propose to aggregate the local RA areas by investor-owned utility (IOU) service territory. They argue that this will provide more flexibility for LSEs that are buying and selling local RA capacity. Since the San Diego local area is known to be resource constrained, a special rule for that area may be needed. SES/TURN proposes a rule that would allow the transfer payment mechanism used in 2010 to continue for only the SDG&E service area. Lastly due to asymmetry, the three IOUs would be required to sell their excess local RA capacity periodically through the refueling outage process.

SES and TURN propose a decision point in either the end of the 2010 or the beginning of 2011, to determine "whether a sufficient liquid, tradable local RA capacity (i.e., Standard Capacity Product) has successfully emerged to facilitate the commercial aspects associated with a local RA capacity True-Up."[5] A decision at this point would allow the Commission the opportunity to assess whether the default transfer payment mechanism that was adopted in Rulemaking (R.)07-05-025 should continue for the 2011 compliance period.

In addition to the True-Up Approach, SES and TURN proposed a second idea, which will be called the "Reallocation Method." The Reallocation Method is based on reallocating the local RA obligation to LSEs using an LSE's updated August coincident peak load forecast. The Reallocation Proposal "builds directly on the current processes being employed by the CEC and Energy Division staff for allocation in the year-ahead local RA capacity obligation, in approving the monthly adjustments to LSEs' load forecasts for System RA capacity compliance purposes and in calculation of CAM [cost allocation mechanism] and RMR [reliability must-run] allocations."[6]

The Reallocation Method has LSEs submit a revised coincident peak demand forecast for August 2011 in April 2011. This forecast is used as a means to recalculate and redistribute any local RA obligation that may have migrated. The LSEs would receive their local RA reallocation in May 2011 and would have 30 days to procure any additional local RA capacity. The first local true-up would be made June 1, 2011 (pre-summer true up). This same cycle would then begin again in August 2011 with the revised forecast due, followed by the

5 Joint Phase 1Comments of SES and TURN at 3.

6 Semi-Annual Local RA Capacity Reallocation to Account for Load Migration Proposal at 1.

reallocation of their local RAR in September, and followed by a second showing on October 1, 2011 (post summer true up).

PG&E supports a modified version of the True-Up Approach. PG&E argues the 5 MW threshold for reporting load migration should not be adopted because such a threshold could effectively penalize the LSE losing load by not compensating it for the costs of local RA now being used to meet the needs of the LSE gaining the load. Additionally, PG&E proposes to modify the proposal to adopt monthly payments. The primary concern that PG&E has with the reallocation method is that it considers changes to local RA only two times for the year.

SCE recommends the Commission not adopt the Reallocation Method because it does not provide any detail as to how the LSEs' revised August coincident peak demand forecasts will be validated and policed for accuracy. Additionally, SCE argues that the Reallocation Method assumes a "best estimate" that does not necessarily account for all customers. SCE is also concerned that allowing only a single month to procure additional local RA capacity could result in additional market power issues associated with the urgency of completing the transaction.

SCE supports a modified version of the True-Up Approach that allows for the unbundling of the local attribute from system RA capacity. SCE believes that by disaggregating the local attribute it will increase liquidity in the local RA capacity market. Additionally SCE interprets D.10-03-022 as unbundling the local attribute subject to an administratively determined price.

SCE does not support a decision point in late 2010 or early 2011 to assess the default transfer payment. SCE requests the Commission not adopt the default transfer payment for 2011, stating: "Effectively, the default transfer payment creates a free option for local capacity buyers. Allowing the market to establish prices will result in the most efficient outcome that will be beneficial to both buyers and sellers alike."[7]

AReM disagrees that SCE's modification will create a more liquid market for RA. AReM is concerned that unbundling and sales of the local attribute would undermine the development of local RA capacity market. AReM supports the True-Up Approach with a decision point in late 2010 to conclude if a liquid, tradable capacity market exists.

TURN requests that unbundling of the local attributes from local capacity be deferred until more experience in this area is gained. DRA supports the True-Up Approach, and unbundling of the local attribute. SDG&E supports the True-Up Approach.

Calpine supports the True-Up Approach but does not support the transfer payment section established in the DA decision. They request that if a transfer payment mechanism is maintained then additional rules need to be created to monitor its use.

3.2.2.2. Discussion

The local true up mechanism adopted in the DA decision is mostly consistent with the True-up Approach proposed in this proceeding. The main difference between the two is that the true up mechanism in D.10-03-022 for 2010 adopts a default transfer payment price for local RA:

> "The default transfer payment would provide an administrative price for the transfer of local RA credits of $24 per kW-year. This amount is intended to reflect only the "premium" value of local RA

[7] SCE reply comments at 6.

> capacity over System RA capacity, since the LSEs acquiring new load would still be purchasing any increased amount of System RA capacity required to be shown in its monthly System RA filing under the current RA load migration rules. Rather than a flat $2.00 per kW-month, the monthly prices would be "shaped" to reflect the fact that RA capacity is most valuable during the peak summer months. This shaping would spread the $24 over the months of the year based on the same factors (shown below) that were used to allocate capacity payments under the CAISO's former Reliability Capacity Services Tariff program across the 12 months of the year. In mathematical terms, the transfer payment would be determined as follows:
>
> CLO ***x*** $24/kW-yr ***x*** Shaping Factor for remaining months of 2010."[8]

To this point, parties have commented mostly on the True-Up Approach, and less on the Reallocation Method. We will not adopt either the True-Up Approach or the Reallocation Method at this time, but will take further comments after this decision.

We are not convinced at this time that the True-Up Approach should be adopted. Elements of the proposal have raised concern with many parties. These concerns include the use of a transfer price, the unbundling of the local attribute, the forecast method being employed, the 5 MW threshold of load migration in each IOU territory, the aggregation of areas by IOU service territory, and the treatment of SDG&E. These concerns would be best answered with experience from the current local true method being used. Therefore, before adopting a local true up method for 2011, we wish to consider the experience gained in 2010.

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[8] D.10-03-022 Appendix 3.

We also wish to consider further the Reallocation Method. The key advantage of the Reallocation Method appears to be that it builds on the current method employed by the CEC and Energy Division to reallocate CAM and RMR allocations as well as to adjust monthly system requirements for load migrations. Adopting the Reallocation Method, or something similar, could alleviate the need to oversee the transfer payment mechanism and problems associated with monitoring individual customer movements and transactions. This would provide all parties with less of an administrative burden associated with a new process. On the other hand, the Reallocation Method does not provide the LSEs with the exact local RA capacity true-up obligation until after the CEC and Energy Division recalculate reallocations. Further, it also only gives LSEs 30 days to procure any additional need local RA capacity.

Some parties propose a decision process later this year to revisit the adopted local true up methodology based on experience with the first two local RA true up filings during 2010. We agree that the recently adopted local true up process presents an opportunity to evaluate the adopted process. We can then take what we have learned from the local true-up process in 2010 and make a decision for 2011 based on the record and that experience.

We accept TURN and AReM's suggestion to re-evaluate the 2010 local true up during a decision phase later this year, once there is sufficient experience gathered with the local RA true up mechanism adopted in the DA proceeding. However, in light of our plans to revisit this issue later in 2010, once experience has been gathered with the true-up mechanism adopted by D.10-03-022, we encourage parties to give serious consideration to the Reallocation Method.

3.2.3. Aggregation of Local Areas

To address supplier market power concern, D.06-06-064 established an approach for aggregation of certain local area for 2007. After determining each LSE's local RA obligation in each local area, the Commission determined that six local areas within the PG&E territory (Humboldt, North Coast/North Bay, Sierra, Stockton, Greater Fresno, and Kern) should be aggregated as one for purposes of RA compliance. These are known as the "other PG&E" local areas.

Given the local resource constraints identified by the CAISO in the "other PG&E" local areas, we conclude it is best to keep the local areas aggregated for 2011. One of the purposes of the LCR studies is to identify the local constraints in the coming year. Given the 2011 LCR 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. However, this decision is linked to the outcome of the LCR study which is done annually and runs simultaneously with the RA proceeding. Therefore, we reject AReM's proposal, to make this aggregation permanent, and will revisit the aggregation of the "other PG&E" local areas annually with the results of the LCR study.

3.2.4. Local Area Deficiency

The Commission in previous resource adequacy decisions (*See*, e.g. D.06-06-064 at 21-22) provided that an LSE cannot be required to procure capacity that does not exist, in situations where the local area resource need is higher than existing capacity. The Scoping Memo determined that continuation of this "blanket waiver" should be a Phase 1 topic.

AReM proposes that the "blanket waiver" be made permanent so that we do not have to revisit it every year. We do not see a situation in the immediate future where there will be no need for this waiver. We therefore adopt AReMs proposal to make the "blanket waiver" a permanent part of the RA program for 2011 and onward, but reserve the right to revisit it if needed.

4. RA Program Modifications

4.1. Standard Capacity Product

The Standard Capacity Product (SCP) is an attempt to reduce transactions costs associated with buying, selling, and trading capacity to meet RA requirements. In order to meet this goal, the SCP seeks to standardize the obligations of RA providers and other related terms of RA contracts. As implemented to date, the SCP places contract terms relating to availability standards and penalties in Section 40.9 of the CAISO Tariff.

The Federal Energy Regulatory Commission (FERC) approved the existing SCP on June 28, 2009. In that order, FERC directed the CAISO to work toward extending the SCP to currently exempt resources. At this time, certain resources whose Qualifying Capacities (QC) are determined based on historical data (including Qualifying Facility (QF) resources) and demand response resources are exempt from the SCP.

At the prehearing conference (PHC), some parties argued that ongoing activities in other proceedings would make it difficult to address issues relating to these resources in this proceeding. Further, PG&E pointed out that modifying counting rules for resources which are not part of the SCP would likely be contentious. Other parties argued that a methodology for counting these resources as part of the local procurement obligations could and should be developed in Phase 1 of this proceeding. For example, CAISO suggested that FERC issued an order directing CAISO to end the temporary exemption for demand response resources and various intermittent resources (wind, solar, non-dispatchable cogeneration, non-dispatchable biomass and non-dispatchable geothermal facilities) and this needs to occur for 2011 to be in compliance with the FERC directive.

In order for the SCP to be fully functional, it must be available as a commercially-viable product that LSEs can purchase and trade easily. Parties believe what is necessary is to find a way to end the LSE-based scheduled outage replacement obligation (sometimes referred to as a "replacement reserve" or "planned outage" issue).

Proposals and comments on this topic necessarily interweave our process in this rulemaking and the CAISO's ongoing stakeholder proceeding, which is discussing many of the same issues from the perspective of the jurisdiction of FERC and the CAISO.

4.1.1. SCP for 2011 RA

In D.09-06-028, we stated that "while we defer action on mandating the SCP for RA compliance, contracts that include the final SCP provisions will be eligible to count for RA compliance in 2010."[9] Staff's Workshop Report indicates that this issue was discussed in workshops.[10] TURN commented that it may be too early to mandate the SCP for RA compliance:

> "The product is still in the process of being refined, and parties have reported that a fully liquid market has yet to develop. The adoption of a mandatory requirement would necessarily have to consider the issue of grandfathering of pre-existing contracts, a topic which has not been addressed thus far in this proceeding. While TURN

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[9] D.09-06-028 at 44.

[10] Workshop Report at 5.

> strongly supports the SCP and hopes that it will become a truly standard product for RA compliance purposes, it is simply premature to forbid Load Serving Entities (LSEs) from obtaining RA capacity in other ways."[11]

Due to the ongoing changes to the SCP, for 2011 RA, we will continue the deferral that we adopted in D.09-06-028. SCP contracts will be eligible to count for 2011 RA compliance, but we will not mandate the SCP at this time. We make this determination of continued deferral for all resource types, both those that are currently included in the SCP and those that are currently exempt.

4.1.2. Continue the Exemption for Demand Response

Demand Response (DR) resources are currently exempt from the SCP as adopted by FERC on June 28, 2009. CAISO and SCE argue that DR resources should continue to be exempt from the SCP at this time because there is no viable alternative proposal in the record. While we agree in theory with NAPP and EnerNOC that SCP ultimately should be extended to DR resources, there is no viable proposal to effectuate this change at this time. Indeed, CAISO has not included any proposal to include DR resources in the SCP in the recent draft proposals in the SCP II stakeholder proceeding. We note our support for the extension of SCP to DR resources and encourage the CAISO and other parties to work toward this goal, but we do not have sufficient information to take any further action on this issue at this time.

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[11] TURN Comments at 1.

4.1.3. No Change to Replacement Obligation

At the PHC, many parties suggested that the LSE-based replacement obligation for RA capacity[12] on scheduled outage impedes the viability of the SCP as a commercially viable product. In this proceeding,
two methods for ending the current LSE-based replacement obligation were discussed:

- Include "delivery requirements and penalties and replacement obligations in the [CAISO] tariff" so that "the CAISO then becomes responsible for enforcing delivery rather than each individual LSE, i.e., the CAISO assesses penalties and procures replacement capacity in the event that a supplier is unable to deliver RA capacity that has been sold and pledged for RA compliance."[13] We refer to this approach as "tariff-based replacement."
- "[A]dd a Planned Outage Adder (POA) to each LSE's RA Requirement. The POA would account for planned outages that the [CAISO] has historically approved at-the-time-of the monthly supply plan submittal."[14]

Calpine notes that the tariff-based replacement approach has been discussed in RA proceedings for several years.[15] This approach was explored in CAISO's SCP II stakeholder process with strong initial support from stakeholders.[16] For example, AReM "strongly supports the removal of the current LSE obligation to replace RA capacity for units on scheduled outages"

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[12] We adopted this rule in D.06-07-031; see p. 10 of that decision for details.

[13] Calpine Proposals at 5-6.

[14] SCE March 5, 2010 Proposal at 1.

[15] SCE March 5, 2010 Proposal at 1.

[16] SCE March 5, 2010 Proposal at 1.

and suggests that, "ESPs do not control the RA units or have any knowledge about when outages may be scheduled. The most logical approach, therefore, is to transfer this obligation to the RA seller and incorporate the obligation into the CAISO's tariff."[17] However, no consensus has been reached around the details of how this approach should be implemented. At the time of comments in this proceeding, many parties noted that they could not support the tariff-based replacement approach as it was being discussed at the time in CAISO's SCP II stakeholder process.[18] SCE, for example argues that the proposal at that time would lead to increased costs due to CAISO procuring replacement capacity for all outages and therefore "effectively result in the procurement of capacity above what the CAISO currently relies on."[19] CAC suggests that we should, "either maintain the current [LSE] scheduled outage replacement obligation or exempt Combined Heat and Power (CHP) resources from any rule that moves the obligation to suppliers."[20] Finally, the tariff-based replacement approach has been removed from the scope of CAISO's SCP II stakeholder process.[21]

Although many parties suggest that SCE's POA approach holds promise[22] some raised concerns. For instance, Calpine claims "[t]wo potential areas of concern are the monthly shaping of the procurement obligation and cross-

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[17] SCE March 5, 2010 Proposal at 1.

[18] SCE March 5, 2010 Proposal at 1.

[19] SCE March 5, 2010 Proposal at 1.

[20] SCE March 5, 2010 Proposal at 1.

[21] CAISO Revised Draft Final Proposal at 7; http://www.caiso.com/2771/27717a905e6a0.pdf.

[22] See: CalWEA/CCC Comments pg 11; WPTF Comments at 3-4; Calpine Comments at 10; Dynegy Comments at 7; and Mirant Comments at 5-6.

subsidies from suppliers who require relatively few planned outages to those who require more extensive planned outages."[23] Dynegy's concern is that RA sellers must be able to take planned outages.[24] SDG&E notes that it "is not inclined to support" the POA approach.[25]

Parties noted that the POA approach is a modification to the overall RA structure. AReM "requests that the Commission defer consideration of any alternative proposals for modifying the structure of the RA program to a separate proceeding that integrates RA with the Planning Reserve Margin (PRM) proceeding and record."[26] WPTF suggests that the "most efficient solution to the scheduled outage issue is simply to base the system reserve margin on the annual peak."[27]

In conclusion, we have no viable CAISO tariff-based replacement approach before us and the POA approach is not fully developed. Numerous parties suggest that it is premature for us to act on this issue.[28] TURN suggests that we "pursue an expedited process to resolve this single issue via a "Phase One B" decision in July or August of this year at the latest."[29] We decline to modify the existing LSE-based replacement obligation at this time. While we

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[23] Calpine Comments at 10.

[24] Dynegy Comments at 7.

[25] SDG&E Comments at 7.

[26] AReM Reply Comments at 4.

[27] AReM Reply Comments at 4.

[28] DRA Comments at 2; CAISO Comments at. 2; CLECA Comments at 5; SDG&E Comments at 5; CAC Reply Comments at. 10; and PG&E comments at 10.

[29] TURN Reply Comments at 3.

appreciate TURN's suggestion of a "Phase One B" to resolve this issue, we believe that the complex issues related to scheduled outage replacement are not well suited to an expedited process. We encourage CAISO and other parties to continue exploring the tariff-based approach in CAISO's stakeholder processes. Finally, we note that SDG&E argues that, "replacement capacity should be mandated only when the system would fall below 115% of the expected monthly load during the scheduled outage."[30] We encourage CAISO and other parties to explore this approach in future efforts to remove the LSE-based replacement obligation.

4.2. Qualifying Capacity

On December 18, 2009 the Energy Division published a report on "Qualifying Capacity Calculation Methodologies" (QC Report). The QC Report seeks to describe all currently applicable CPUC methodologies relevant to calculating the qualifying capacity (QC) of RA resources, some which were adopted in previous Commission decisions and others which have been implemented more informally. In addition to the current methodologies, the QC Report includes a number of staff proposals for changes; in this proceeding parties have made further proposals to modify the calculation methodologies. Parties have commented extensively on the QC Report and the staff and party proposals.

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[30] SDG&E Reply Comments at 1.

We adopt a QC Methodology Manual as discussed below and as attached to this decision (Appendix B).[31] The QC Methodology Manual incorporates methodologies previously adopted both formally and informally in the past, and new and revised methodologies discussed in the QC Report and in parties' comments on the QC Report. In future RA proceedings, parties wishing to make changes to the QC calculation methodologies should include proposed revised or added text of the QC Methodology Manual.

In this proceeding, some parties proposed reconsideration of the wind and solar QC methodology. This issue was discussed at length in R.08-01-025 and was decided in D.09-06-028; we decline to reconsider it here.

4.2.1. Resource Classification Proposals

Section 3 of the QC Report describes the process of classifying resources; the classification process is critical because it determines which of the QC methodologies applies to each resource. Section 3.1 of the QC Report describes the Energy Division's proposal to allow resource owners and scheduling coordinators to propose changes to the classification of their resources, with appropriate justification.

CAC makes several proposals relevant to the classification and QC of CHP or cogeneration resources. We will address these proposals one at a time. However, before addressing the merits of the proposals, we note that staff, in the QC Report, refers to these resources as "cogeneration" resources. In the record of this proceeding, parties have usually used the term "CHP." We understand

[31] For clarification, we use the term "QC Report" to refer to the Energy Division document used in workshops, while the "QC Methodology Manual" is what is adopted today.

these terms to be synonymous; for consistency, we will use the term CHP in this decision and the relevant sections of the QC Report are updated accordingly.

CAC proposes to "automatically [deem] non-dispatchable any resource that signs a [Qualifying Facility (QF)] [Participating Generator Agreement (PGA)]." SCE responds that the language of a QF PGA does not "mandate that these resources be non-dispatchable, and would not limit a resource with a QF PGA from entering into an agreement with an LSE for dispatchability." In response, CAC proposes that if a CHP resource sets operating limits in its QF PGA that render the resource non-dispatchable, the resource should be deemed non-dispatchable for net qualifying net qualifying capacity (NQC) counting purposes.

Further, CAC proposes that the counting methodology should differentiate between firm, as-available and hybrid CHP generation. CAC contends that this characterization more accurately reflects the generators' operational characteristics. This proposal is widely opposed.[32] For example, Calpine contends "it provides no assurance that such [firm] resources would actually provide energy at levels consistent with their available capacities during peak periods."[33]

We note that the classification methodology proposed by the Energy Division in Section 3.1 of the QC Report allows for case by case determination of the dispatchability classification of individual resources, including CHP. No party opposed the Energy Division's proposal on classification. The Energy

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[32] See: CAISO Comments at. 21, Calpine Comments at. 4-6, Dynegy Comments at 14, PG&E Comments at 4, and SCE Comments at 21-22.

[33] Calpine Comments at 6.

Division's proposal allows the specific details of a resource's operational characteristics, both physical and contractual, to be considered in its classification. Further, the resource owner or scheduling coordinator is best able to make this determination. Moreover, especially in light of the fact that SCP availability standard already applies to dispatchable resources, we believe the resource owner and scheduling coordinator have proper incentives to classify the resource appropriately. Therefore, we do not adopt the CAC classification proposals; instead, we adopt the staff proposal as part of the QC Methodology Manual.

4.2.2. Counting Rules for Non-Dispatchable Resources (QC Report - Section 10)

Section 10 of the QC Report describes the methodology for calculating the QC of non-dispatchable resources that are not explicitly described in other sections. In Sections 10.1-10.3, the Energy Division proposes two changes: a methodology for new non-dispatchable resources (a topic that this Commission has not previously addressed) and a modification to the measurement hours, consistent with our D.09-06-028 for wind and solar resources. No party opposed either of these proposals.

CAC proposes to calculate NQC on a monthly basis as opposed to a summer-months average for the entire year. In response, PG&E suggests that this approach should be applied to all non-dispatchable resources. SCE suggests that, if the Commission adopts CAC's proposal, it should also clarify that dispatchable thermal units are also able to receive monthly QC values.

A number of other resource types (e.g. wind, solar, and demand response) already have monthly QC values. The approach proposed by CAC to use monthly QC values for CHP is consistent with other previously adopted methodologies. The CAC proposal and both SCE and PG&E's suggested modifications are reasonable. Many dispatchable thermal units already do modify their NQC periodically during an RA compliance year and are thus able to take advantage of seasonal changes in available capacity. We adopt the proposal to calculate a monthly QC for all non-dispatchable resources, as part of the QC Methodology Manual.

CAC proposes to use the new resource methodology proposed by Energy Division for expansions to CHP facilities. SCE opposes this, contending that it will be difficult for the Commission to verify increases in capacity based on expansions. CAC claims that the procuring LSE or the CAISO may be able to verify the increase in capacity under the terms of the LSE's power purchase agreement or the generator's QF PGA.

While we are sympathetic to CAC's objection that additions to the generating capacity of an existing CHP resource may not be realized by the existing counting rules and the Energy Division's proposal, the CAC's proposal is not sufficiently developed at this time. We share SCE's concern that we do not have the ability to verify resource additions or subtractions to CHP resources. Although we will not adopt CAC's proposal today, we note that we support the policy goal of accurately and promptly measuring the capacity of expansions to CHP resources. We hope that this issue will be resolved in the future and we encourage CAC to work with the CAISO and LSEs to develop a framework to inform us and our staff of resource changes so that additions and subtractions may promptly be reflected in QC values. Aside from CAC's proposed revisions, no party opposes the Energy Division's proposal to measure the QC of new non-dispatchable resources using an approximation based on existing non-dispatchable resources. This proposal provides a reasonable approach to address a gap in our previously adopted rules, and it is approved as part of the QC Methodology Manual.

No party opposes the Energy Division's proposal to change the hours of measurement for non-dispatchable resources. This proposal is consistent with D.09-06-028 and is adopted. The QC Methodology Manual incorporates the two staff proposals and the CAC proposal to use monthly QC calculations.

4.2.3. No Change to the Counting of Distribution Resources

PG&E proposes that distribution level resources that are not otherwise being counted for RA should be counted and should follow the same counting rules as resources connected at the transmission level, except that the distribution level resources will be deemed deliverable by the Commission. SCE agrees with PG&E that there may be some resources that are not properly accounted for by current counting rules, but is concerned that the Commission is not in a position to determine the deliverability status of all distribution resources. The CAISO expresses concern with deeming these resources deliverable.[34] TURN, in referring to the Energy Division's February 18 Workshop Report, states:

> "TURN fully agrees with the Energy Division's suggestion that "all resources should either be counted [as a reduction] in the load forecast or as a resource, but it is important to avoid double counting." Indeed, this seems to reflect simple common sense. The problem may therefore be more of an implementation question than a policy issue, one that will require some coordination between the CEC's load forecasting process and the CPUC's counting rules for distributed resources."

[34] CAISO Comments at 17-18.

We agree with TURN and SCE that the record of this proceeding does not identify a specific class of distribution level resources that may not be currently counted either as demand reductions or as supply. Indeed, Section 4 of the QC Report describes the deliverability of distribution level resources, yet no party has clearly stated that that description is inaccurate. If a party does identify an error in the description in the QC Report or a class of resources that is currently neither treated as demand reduction nor as supply resource, we encourage that party to describe the concern to the Energy Division and to bring the issue to the attention of this Commission. Further, as PG&E and SCE note, the deliverability of resources less than 20 MW connected to the transmission system is being discussed in CAISO's stakeholder process on Small Generator Interconnection Procedure. SCE further contends it is likely that the IOUs will modify their distribution interconnection procedures consistent with the results of CAISO's reform efforts.

We encourage the CAISO and the IOUs to seek a means of assessing the deliverability of these resources so that they may be treated as RA suppliers. Finally, we note the following SDG&E recommendation:

> "SDG&E therefore recommends that each utility include in their distribution-level interconnection studies an assessment of whether the interconnecting generators should be treated as fully deliverable for Resource Adequacy purposes. This determination would establish a rebuttable presumption that the subject resources interconnected to the distribution system on the non-customer side of the meter should be certified as RA resources. If the CAISO believes the utility's determination creates a reliability concern, it can conduct the appropriate deliverability analysis for the amount of generation capacity that reaches the transmission system and present the results to the Commission to rebut the presumption in favor of deliverability."

We will not adopt SDG&E's proposals at this time, but expect these ideas to be discussed in future workshops or comments in this proceeding.

4.2.4. Eliminate Forced Outages and Derates from Data to Calculate QC and Possibly Include Resources Using Historical Data in the SCP

As noted above, resources which rely on historical production data for the calculation of QC are currently exempt from the SCP. This exemption prevents a double penalty for the same outage: one penalty through a reduced QC and another financial penalty via the SCP availability standard. The CAISO proposes that in order to eliminate the problem of double counting forced outages and derates that the outage hours be eliminated from the data set used for QC calculation. This would allow us, as well as FERC, to extend the SCP to these currently exempt resources. Specifically, the CAISO proposes that the Commission:

> " . . . modify its RA counting rules either to: (1) eliminate forced outage and de-rate hours from its calculation of the QC of RA resources, or (2) use proxy energy output values for those hours. The ISO believes that the second option could be implemented by adopting an approach similar to the methodology the CPUC has previously approved to account for scheduled outages in the QC calculation for these types of resources."[35]

CAISO further notes that it intends to present its proposal to extend the SCP availability metric to these types of resources for consideration at the ISO Board of Governors' meeting (which occurred on May 17-18, 2010), followed thereafter by a tariff filing at FERC to implement the proposal effective January 1, 2011.

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[35] CAISO Proposals at 5.

Both parts of this proposal are controversial. CalWEA/CCC strongly opposes both the proposals to include these resources in SCP and to eliminate the historical outage/derate data. CalWEA/CCC first contend that, "FERC did not intend to direct CAISO to end exemption for intermittents."[36] They further claim that, "the success of the SCP initiative does not at all depend on whether intermittent renewables and CHP projects can be shoehorned into the SCP mold" because RA capacity from these resources is not attractive for trading.[37] Further, they argue that existing incentives, namely the energy payment structure of most RPS contracts make the availability incentive of the SCP needless and duplicative. In summary:

> "Given the disparate RA counting rules, it is simply not possible to fashion an equitable and workable standard availability incentive for all types of resources. Given the strong existing incentives for intermittent and CHP resources to maintain high availabilities, CalWEA and the CCC submit that it is not worthwhile to try to "destandardize" the SCP availability incentive simply so that it can be applied to these resources. As a result, it is reasonable to retain the exemption for these resources."[38]

DRA shares this view arguing that imposing an availability metric on intermittent resources that receive only energy payments and no capacity payments does not make sense and that there will be no increase in the availability of these generation resources. Finally, CalWEA/CCC suggest that the Commission will be faced with requests from renewable and CHP generators in the Renewables Portfolio Standard (RPS) and QF dockets to revise the pro

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36 CalWEA/CCC Comments at 2-3.

37 CalWEA/CCC Comments at 6.

38 CalWEA/CCC Comments at 10.

forma contracts applicable to these resources in order to remove the existing incentives that would be duplicated by the SCP mechanism.

CAC similarly argues that the Commission should ensure that CHP generators are not penalized twice for the same forced outage. Therefore, CAC contends the SCP should not apply to exempt resources until the issue of double penalties is resolved. CAC believes we do not have sufficient information in this proceeding to make that determination and that we should defer the issue of including these resources in the SCP.

Dynegy, however, responds to the arguments that SCP incentives would be duplicative by stating: "If the energy-based power purchase agreements that the representatives of these intermittent resources assert provide sufficient availability incentives for these resources, it's not at all apparent why they do not also provide sufficient revenues that would obviate the need for these energy resources to fight for poorly-fitting capacity payments."[39]

CalWEA/CCC contend that utility-owned intermittent and CHP generation may not have as strong of incentives as generation under contract to an LSE, and therefore we should evaluate whether to remove the SCP exemption for such utility-owned projects. However, CalWEA/CCC do note that many of the existing wind and solar resources operate under grandfathered QF contracts and thus will not be subject to the SCP until those contracts expire. Further, they state that "[o]nly a fraction of the existing intermittent and CHP generation is under the CAISO's outage reporting system; the remainder is existing QF

[39] Dynegy Reply Comments at 5.

generation that is grandfathered out of these reporting requirements."[40] CalWEA/CCC claims that many currently exempt resources will be grandfathered from the SCP for the term of their current contracts, thus allowing time for the parties to those contracts to work out appropriate frameworks for incorporating the SCP availability standard.

Consistent with the CAISO tariff, and simple fairness of avoiding a double penalty, we find that eliminating the historical outage and derate data from the data set used to calculate the QC of these resources is an important pre-condition to including these resources in the SCP. Within the decision of whether or not to eliminate outage and derate hours, an important sub-decision is what hours should be eliminated. It is fair that exactly the same types of hours should be eliminated from the data set as are subject to penalties under SCP.
Section 40.9.4.2 of the CAISO Tariff states that, "Forced Outages, non-ambient de-rates, or temperature-related ambient de-rates" are considered for the availability calculation. Therefore we will eliminate these hours from the data set used for calculation of QC. Further, we find that it is appropriate to extend the methodology of replacing these hours with proxy data, in the same manner we adopted for scheduled outages in D.09-06-028 and as proposed by CAISO and the IOUs in this proceeding.[41] The QC Methodology Manual in Appendix B details this methodology.

Further, we expect that the SCP ultimately will be extended to include resources that use historical data as the basis of their QC (e.g., wind, solar,

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[40] CalWEA/CCC Comments at 7-8.

[41] PG&E Comments at 5; SCE Comments at 8; SDG&E Comments at 8.

combined heat/power). We have noted in many previous decisions our support for an inclusive SCP.[42] However, no finalized, FERC-approved SCP for these resources exists at the time of closing the record in this phase of this proceeding. Therefore, we will adopt a similar strategy to last year's D.09-06-028, which accepted the SCP for RA compliance, but did not mandate it. We have already discussed in Section 4.1.1 that we will defer action on mandating the SCP for RA compliance for all resources. If FERC does approve an SCP tariff for resources which use historical data as the basis for their QC later in 2010, the assigned ALJ may take comment in this proceeding to consider mandating SCP contracts for these resources for 2011 RA compliance.

4.2.5. Demand Response

In D.09-06-028, the Commission directed the Energy Division to use the load-impact protocols to the greatest extent possible in developing the qualifying capacity of demand response resources. Since that decision, the Energy Division has developed a document describing the use of load-impact protocols in resource adequacy. This document was included in the QC Report.

The Scoping Memo allowed this issue to be included in the scope of Phase 1 of this proceeding in order to allow comment on the Energy Division's document, with the potential that the Commission would resolve any disputes.

4.2.5.1. Counting Proxy Demand Resource and Supply-Side DR

In this proceeding, EnerNOC suggests that QC of "supply-side demand response" should be determined using registered capacity that has been tested.

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[42] See, e.g. D.09-06-028 at 42; D.06-07-031 at 4; D.05-10-042 at 26; D.04-10-035 at 42.

In justification of this proposal, EnerNOC submits that Load Impact Protocols (LIPs) "are not an appropriate basis either for calculating RA capacity or for determining capacity payments for supply-side resources. Load impact protocols are complicated, non-transparent, and expensive to run."[43] Further, EnerNOC argues, referring to the LIPs, that "A simpler means of determining RA capacity for DR resources participating in the wholesale market would be to take the capacity registered by the [Proxy Demand Resource (PDR)], subject it to a test, and determine the tested capacity as RA-eligible."[44] EnerNOC describes its proposal this way:

> "If California is going to treat demand resources comparably to generation resources, the demand response provider, representing the resource, should be able to register the capacity associated with the resource that is participating through the CAISO. The determination of whether or not the registered capacity is capable of performing at that level will be based upon the actual performance of the resource or, if not called within a commitment period, testing. If the resource does not perform to the capacity level specified, the resource will face penalties."[45]

This proposal provoked considerable controversy. TURN, AReM, and NAPP support the EnerNOC proposal.[46] AReM agrees with EnerNOC that the current approach using load-impact protocols is complex, non-transparent and unduly time-consuming. TURN adds that "If a DR program is willing and able to operate like a supply-side resource, TURN sees no reason why the same

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[43] EnerNOC Proposals at 7.

[44] Ibid.

[45] EnerNOC Comments at 7-8.

[46] AReM Comments at 5-6; TURN Comments at 4; and NAPP Reply Comments at 4-5.

capacity test that applies on the supply side could not be used to determine the QC for these programs."[47]

CLECA, Dynegy, PG&E, SCE, and DRA oppose EnerNOC's proposal.[48] Generally, these parties are concerned about consistency with the load impact protocol (LIP) measurement of other DR programs and the accuracy of EnerNOC's proposal. Dynegy summarizes the issue: "If the Load Impact Protocols are adequate for determining the RA value of IOU demand response programs, EnerNOC has not satisfactorily demonstrated why they are inadequate for determining the RA value for non-IOU demand response programs."[49]

Several parties[50] have characterized the distinction between DR that would use the LIPs and DR that would use a contract capacity as a distinction between IOU operated DR and non-IOU operated DR. We will not make this distinction between IOU and non-IOU DR. Instead, the counting rules for all resources should be operator-neutral, and should only differentiate between resources based on the operational characteristics of the resources. We recognize that in some cases, especially with DR, operational characteristics may be substantially correlated with the characteristics of the resource operator, but we decline to differentiate based on the identity of the operator.

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[47] TURN Comments at 4.

[48] CLECA Comments at 4; Dynegy Comments at 13; PG&E Comments at 4; SCE Comments at 23-26; and DRA Reply Comments at 9.

[49] Dynegy Comments at 13.

[50] SCE Reply Comments at 11.

SCE contends that EnerNOC's proposed methodology is overly simplistic and unreliable because it cannot control for variations in conditions at the time of different DR events. Further, SCE suggests that this approach may result in artificially inflating QC values for DR resources.

In response to SCE's concerns, EnerNOC explains that it uses a portfolio of different customers: "This process of portfolio development allows EnerNOC to register a DR resource that is highly reliable and will perform at a predictable level irrespective of conditions at the time of the event."[51] Further, EnerNOC notes that an underperforming Proxy Demand Response resource "will be charged the uninstructed deviation for any real-time shortfall in its performance relative to day-ahead bids and potentially sanctions for failure to provide the resource up to the committed level," and that "consistent underperformance will result in . . . QC being appropriately adjusted downward."[52]

From a policy perspective, we agree with TURN and EnerNOC that with proper economic incentives for accuracy, it is reasonable that DR resources that act like a dispatchable supply resource may appropriately have QC evaluated via a test, similar to dispatchable conventional generators. We note that parties such as CLECA have expressed concerns with the accuracy of the baseline methodologies used to measure performance of DR resources for settlement purposes; in making this policy determination, we do not need to address the accuracy of the baseline methodologies at this time. It is likely that a DR program that is subject to the RA Must-Offer Obligation to bid into the CAISO

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[51] EnerNOC Reply Comments at 5.

[52] EnerNOC Reply Comments at 5-6.

energy markets is subject to uninstructed deviation penalties for real-time performance problems, and is subject to SCP availability penalties, will have adequate incentives to set a realistic QC for itself and that the CAISO will be able to verify this by a test. However, no party has demonstrated that any DR resource or class of DR resource before us today meets this description.

In conclusion, we reiterate our policy view that dispatchable DR resources with financial incentives for availability and performance comparable to those of dispatchable supply resources should be able to receive QC with a comparable testing methodology. However, unless and until it is demonstrated to us, in this or a future RA proceeding, that such a DR resource exists, we will retain our current policy that the LIPs are used to establish the QC of DR resources to the maximum extent possible.

4.2.5.2. Grossing-Up DR for Avoided Line Losses

PG&E and SCE propose to "gross-up" the QC of dispatchable DR resources for avoided line losses. The QC report states that DR suppliers may submit LIP data with and without including avoided line losses, but that LIP data without line losses shall be used. PG&E and SCE argue that the load forecasts used to determine RA requirements include line losses and that DR resources avoid line losses by reducing the need to transmit power over the transmission and distribution (T&D) networks. Therefore, DR resources should receive the benefit of avoiding these losses. DRA, SDG&E, and TURN all support this proposal.[53] SCE proposes[54] the following equation to implement this proposal:

[53] DRA Comments at 3; TURN Comments at 3-4; SDG&E Comments at 9-10.

DR RA Value = 1.15 * DR Load Impact * (1.00/(1.00 – T&D Line Loss Rate)) *where*, T&D Line Loss Rate = 3% + IOU-specific Distribution Loss Factors.

SCE further cites D.06-07-031, which adopted a 3% transmission loss factor and D.05-10-042 which adopted utility specific distribution loss factors. Objecting to this proposal, CAISO asserts that, "the fundamental assumption underlying the proposals is that demand response will in all locations and all circumstances reduce line losses but that the rest of the RA resources will not."[55] In response, SCE claims DR avoids line losses because the resource is supplied at the customer meter level, and, therefore, eliminates the need to account for T&D line losses. TURN would support the use of a "gross up" for losses, unless and until it is shown that in the specific situations, line losses are not in fact avoided by the operation of DR.

We agree with TURN and SCE and find that losses are included in the load forecast used for RA requirements and that DR resources provide a means of balancing supply and demand without accruing line losses. SCE's proposal is a reasonable means of accounting for the line losses avoided by DR. Therefore, we adopt the proposal to gross up dispatchable DR for avoided line losses, including the formula proposed by SCE.

4.2.5.3. Continued Full Year Local RA Credit for Air Conditioner Cycling (AC Cycling) Programs

The CAISO proposes that the Commission "modify the load impact protocols discussed in Section 11 of the QC Report so that they count demand

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[54] SCE Proposals at 9 and SCE Comments at 18.

[55] CAISO Comments at 19.

response resources enrolled in air conditioning cycling programs as local RA capacity only in the summer months when the resources are actually available and capable of performing."[56] The CAISO's primary concerns with the counting rule are based on the fact that, at the current level of participation in demand response air conditioning cycling programs, this approach allows approximately 900 MW per month of "phantom" demand response to be counted as local RA capacity during each of the non-summer months.[57]

Dynegy[58] supports the proposal to only count AC Cycling programs during the summer months, but several other parties[59] oppose the proposal. Parties opposed to the CAISO proposal suggested that the status quo is consistent with many other aspects of the current RA program. TURN[60] summarizes:

> "While the AC cycling *programs* may not be available during the winter, the associated AC *load* also is not there in the off-peak months, which should translate into a lower local RA requirement. But the CAISO does not believe that it is practical to develop monthly or seasonal local RA obligations, because of the extensive amount of work that would entail. TURN submits that it makes little sense to require LSEs to acquire *replacement* local RA capacity in the *off-peak months* because of the absence of AC cycling when we don't even know what the real need for local RA capacity really is in those same off-peak months."

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[56] CAISO Proposals at 10.

[57] CAISO Comments at 11.

[58] Dynegy Comments at 12.

[59] DRA Comments at 3, TURN Comments at 4-5, SDG&E Reply Comments at 7, PG&E Reply Comments at 1.

[60] TURN Comments at 4-5.

The entire structure of the local RA program uses summer peak values for not only load forecasts, but all supply resources. We believe that this conservative approach provides a significant margin of safety in the off-peak months. Therefore, we will continue the current treatment of AC Cycling programs, which is consistent with the larger local RA program.

4.2.5.4. Changes to Measurement Hours will be Effective in 2012

In Section 11.1 of the QC Report, Energy Division proposes that, for consistency with other QC counting rules, DR programs should be measured over the same hours as other resources.[61] DRA supports the Energy Division's proposal.[62] Staff noted[63] that the measurement hours proposed do not align with the hours of operation of some current DR program designs and asked for feedback from the IOUs about when the program designs could be changed accordingly. PG&E suggested that, "Consideration of any potential change in the time period used to evaluate the RA value of the DR programs by the Commission should be aligned with consideration of design changes (i.e., operating hours) to future DR programs."[64] SDG&E suggests:

> "For ease of administration, however, SDG&E urges the Commission to refrain from implementing the proposed change in hours until the 2012 RA compliance year. As noted in the January workshop, the proposed hours do not align with most current IOU demand response program designs. The currently approved IOU demand response program cycle runs from 2009 through 2011.

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[61] QC Report at 25.

[62] DRA Comments at 3.

[63] February 18, 2010 Workshop Summary at 5.

[64] PG&E Comments at 2.

> Beginning in early 2011, IOUs will begin filing applications for the 2012 – 2014 demand response program cycle. SDG&E believes that the proposed change in hours could be incorporated into the 2012 – 2014 applications, and if approved, implemented in the 2012 programs."[65]

TURN makes the same suggestion and adds that:

> "TURN believes that this Commission should endorse the principal of employing the revised hours at this time, so that everyone will be on notice that program changes may need to be considered in the next round of DR program applications. Since those applications are likely to be filed in early 2011, this year's RA decision would the appropriate place to establish such policy guidance, so that it can be taken into account in the upcoming utility applications."[66]

SCE, however, opposes the change in measurement hours,[67] citing D.09-08-028, which adopted specific hours of operation (2 p.m. to 6 p.m.) for SCE's Critical Peak Pricing program.[68] SCE contends that this General Rate Case decision operates on a different three year cycle from the three-year program cycle for DR described in SDG&E's comment above. Therefore, SCE claims it may not be possible to modify the Critical Peak Pricing program for 2012.

We wish to avoid unintentionally under-valuing DR programs which cannot immediately adapt to new measurement hours. Accordingly, we largely agree with the TURN and SDG&E analysis of this issue and believe that DR program designs implemented for the 2012-2014 DR program cycle should be able to incorporate the proposed change in measurement hours. However, we

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[65] SDG&E Comments at 12.

[66] TURN Comments at 3.

[67] SCE Comments at 27 and SCE Reply Comments at 12.

[68] D.09-08-028 at 26.

acknowledge that some DR program designs may not be able to incorporate this change. Therefore, we adopt the staff proposal with the following modifications:

- The proposed change in measurement hours will be implemented for compliance year 2012, but not 2011. Beginning in 2012, the measurement hours shall be the hours shown in Table 2 of the QC Report:

Jan–Mar, Nov and Dec:	HE17 - HE21[69] (4:00 p.m. - 9:00 p.m.)
Apr–Oct:	HE14 - HE18 (1:00 p.m. - 6:00 p.m.)

- 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.

Finally, we note SDG&E's proposal to use a 1-in-10 year forecast in calculating a DR resource's QC with the LIPs. However, we view this as a separate issue from the measurement hours in the staff proposal discussed

[69] HE indicates "hour ending," or the 60 minutes that end at the numbered hour, in 24-hour time. For example, HE17 indicates the 60 minutes beginning at 16:00 (i.e. 4:00 p.m.) and ending at 16:59.

above. This load forecast issue has not been fully vetted in this proceeding and we will not discuss it or adopt it here. If SDG&E or other parties believe this proposed change in the load forecast has merit, they should file a proposal to do so in Phase 2 or a later RA proceeding.

4.3. Implementation Proposals

4.3.1. Resource Adequacy Penalties

Public Utilities Code Section 380 requires the Commission to establish and enforce a resource adequacy program. Past decisions and resolutions establish three primary penalties for different types of RA procurement deficiencies. However, these penalties do not differentiate between deficiencies which are or are not remedied in a timely manner.

The current RA program utilizes the citation program adopted in Resolution E-4017 (as modified by Resolution E-4195) to penalize LSEs for failure to make timely filings in the manner required. The penalty structure is provided in the table below:

	Small Procurement Deficiency	System Procurement Deficiency	Local Procurement Deficiency
Replaced within five business days of the date of notification	$1,500/incident	$9.99/kW-month	$3.33/kW-month

Additionally, D.06-06-064[70] states that LSEs that fail to meet their local RA procurement obligation are subject to a penalty equal to 100% of the cost of new capacity, which is currently determined to be $40/kW-year. D.06-06-064[71]

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[70] At Conclusions of Law 25 and 26.

[71] At 68-69.

further stipulates, in context of local RA filings, that, "the penalty for failure to make a timely filing should, after a grace period not to exceed 10 calendar days, be equal to the penalty for a deficiency." Finally, D.05-10-042[72] states that LSEs that fail to meet their System RA procurement obligation are subject to a penalty equal to 300% of the monthly cost of new capacity.

The Energy Division's staff proposed to modify the current RA penalty structure to provide LSEs with an incentive to promptly cure any RA deficiencies:

	Small Procurement Deficiency	System Procurement Deficiency	Local Procurement Deficiency
Replaced within five business days of the date of notification	$1,500/incident	$3.33/kW-month	$5.00/kW-month
Replaced after five business days of the date of notification	$3,000/incident	$6.66/kW-month	$9.99/kW-month

An alternative proposal was filed by AReM, PG&E, SCE, and SDG&E:

	Small Procurement Deficiency	System Procurement Deficiency	Local Procurement Deficiency
Replaced within 10 business days of the Date of notification	$1,500 first incident in calendar year; $3,000 for each incident thereafter in a calendar year	$5.00/kW-month	$1.70/kW-month
Replaced after 10 business days from the of notification or not Replaced	LSE pays the applicable System or local RA penalty for the deficiency	$9.99/kW-month	$3.33/kW-month

[72] At 94 and Conclusion of Law 21.

Proponents contend that their alternate proposal addresses the Energy Division's needs to add an incentive for LSEs to cure RA deficiencies in a timely manner and also establishing hard deadlines to the penalty rules. SCE claims the alternative proposal is similar to the Energy Division's proposal in that it establishes an incentive to cure promptly a deficiency through the reduction in the penalty amount, with the major difference being that the parties' alternative proposal maintains the current penalty amounts."[73]

Finally, joint parties request to change the RA waiver process. The waiver process established in D.06-06-064 requires LSEs to request the waiver at the time they make their local RA showing. "The waiver request must include both of the following:

(1) a demonstration that the LSE reasonably and in good faith solicited bids for its RAR capacity needs along with accompanying information about the terms and conditions of the Request for Offer or other form of solicitation; and

(2) a demonstration that despite having actively pursued all commercially reasonable efforts to acquire the resources needed to meet the LSE's local procurement obligation, it either:

(a) received no bids; or

(b) received no bids for an unbundled RA capacity contract of under $40 per kW-year or for a bundled capacity and energy product of under $73 per kW-year; or

(c) received bids below these thresholds but such bids included what the LSE believes are unreasonable terms and/or conditions, in which case the waiver request must demonstrate why such an LSE's waiver request that meets these requirements is a necessary but not a sufficient condition for the grant of such waiver. The Commission will

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[73] SCE Comments on Phase 1 issues at 12.

> also consider other information brought to its attention regarding the reasonableness of the waiver request"[74]

The alternative RA penalty proposal requests that this waiver process change to the following:

> "LSE's may request a waiver up to 10 days prior to the year-ahead local RA compliance filing or the True-up Filing for local RA, as applicable. The Energy Division must rule on the request on or before the date the applicable Local RA filing is due. If the Energy Division rejects the waiver request, the LSE will have 15 days form the date of notification of the rejection to procure additional capacity, no penalty will apply unless the LSE fails to cure the deficiency within the 15 days of notification of rejection. The Commission should state in a decision that, barring an overriding demonstrable circumstance, satisfaction of the requirements in D.06-06-064 is a sufficient condition to grant a waiver request."[75]

TURN supports the alternative proposal penalty levels.

Dynegy, J.P. Morgan and Calpine support the Energy Division staffs proposal to triple the local RA deficiency penalty. These parties feel that penalties for RA deficiencies should reflect the greater importance of local resources for grid reliability. Calpine contends that "penalties should be related to the potential harm caused by deficiencies."[76] In addition, Calpine does not support conditions on the blanket waiver approval. Dynegy supports the Energy Division's proposal that modifies the RA penalty structure to increase the penalty for a local deficiency, but does not support reducing the penalty amount for a deficiency in system RA capacity.

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74 D.06-06-064 at 72-73.

75 Alternative Proposal to Modify Current RA Penalty Structure at 6.

76 Calpine comments at 3.

DRA argues that there is no need to modify the current RA procurement penalties. DRA claims that most of the deficiencies in procurement are related to the local RA that is due to shortage of local supply issues, so that increasing the level of penalties will not solve this problem.

SDG&E supports the alternative RA penalty proposal. PG&E recommends the Commission adopt the alternative proposal because it provides additional leeway for correcting deficiencies and moderates the penalty levels.

4.3.2. Discussion

We will adopt a new RA penalty structure which combines parts of the Energy Division's proposal and the alternative structure proposed by certain parties, as shown below. The new penalty structure will be in effect for violations which occur after the date of this decision.

	Small Procurement Deficiency	System Procurement Deficiency	Local Procurement Deficiency
Replaced within five business days of date of notification	$1,500 first incident in calendar year; $3,000 for each incident thereafter in a calendar year	$3.33/kW-month	$3.33/kW-month
Replaced after five business days from the date of notification or not replaced	LSE pays the applicable System or Local RA penalty for the deficiency	$6.66/kW-month	$6.66/kW-month

A problem with the existing penalty structure is that it provides no guidance as to what happens if the LSE does not replace capacity within the specified number of business days after notification. While it is important for capacity to be replaced quickly, the LSE may choose not to do so. For example, an LSE may find it to be less expensive to pay the penalty than to fix the procurement deficiency. Therefore, it is appropriate to both provide an incentive for timely replacement and to provide a clear and increased penalty if this does not occur. The adopted new penalty structure meets both of these objectives.

The adopted penalty levels include stricter penalties for small procurement deficiencies than proposed by the Energy Division, which should encourage close attention to such circumstances. The adopted levels also simplify both proposals by equalizing penalty levels for local and system procurement deficiencies. This is done because there is disagreement among parties as to whether local or system procurement deficiencies should have higher penalties; with no clear answer to that question, we will simply equalize penalty levels for all deficiencies.

We adopt the Energy Division's proposal to eliminate the 10-day grace period that was adopted in D.06-06-064[77] The RA program was set up to ensure that LSE had enough resources procured to meet the forecasted demand that they supply. The program requires an annual Year-Ahead filing where LSEs are to show 90% of their system requirements for the upcoming compliance year. Additionally LSEs are required to make monthly Month-Ahead showings that show they meet 100% of their RA requirements for the coming compliance month. After filing their showing for the month ahead, the Energy Division staff checks their showing for compliance and the CAISO validates their resource showing using the supply plans submitted by the generators. This process can take 1-2 weeks to complete. Once everything has been checked, correction notices are sent out to LSEs to correct their monthly showing within seven calendar days. This is followed by a second supply plan validation, if they have

[77] D.06-06-064 at 68-69.

to show additionally resources to their RA showing. The second set of supply plan validations could take up to another week. In order to implement this program efficiently and ensure that enough resources are procured for the month ahead LSE can not be given a 10-day grace period.

Additionally, we reject the alternative RA penalty proposal to change the local waiver process and requirements. Historically, the local waiver only has been applied for a total of two times. It has been approved one of those two times. The rejection of the other application was due to the LSE not meeting the established criterion. During this proceeding, the Energy Division published both the letter approving the waiver and the resolution denying the waiver on its website, as requested by parties. This was done to provide parties with the transparency and more certainty around the waiver process. Given the historical background surrounding the local waiver, we feel there is no need to add any additionally language to the rules surrounding its process.

Finally, we adopt the Energy Division's proposal to round RA deficiency penalties up on a monthly basis. Current practice is to round up on a monthly basis and we see no need to modify this at this time.

4.3.3. Load forecast timeline

In addition to the RA penalty proposal, the Energy Division at workshops proposed a timeline for changes to the load forecast. Staff notes that LSEs currently submit a month ahead forecast 60 days prior to the month they are forecasting. The monthly load forecast is submitted 30 days before the filing of the Month-Ahead RA showing. This monthly load forecast is used as part of the month-ahead compliance check because it may change the load forecast which in turn changes the RA obligation. In some cases, LSEs have filed updates to their load forecasts after they file their month-ahead RA showing. The Energy

Division proposes that LSEs may, at the discretion of CEC staff, file changes to their load forecasts up to 25 days before the due date of the month-ahead compliance filings. Staff further notes that with the implementation of Senate Bill 695, load migration is anticipated to increase and this may lead to more requested changes in the load forecasts.

No party commented on this proposal. We see this proposal as reasonable as an administrative part of running the RA program. We adopt the Energy Division's Division timeline for changes to the load forecast.

4.3.4. RA Record Retention Policy

Currently there is no established timeline for the RA record retention process. With expected load migration due to re-opening of direct access, and the effect load migration has on the month-ahead RA showing, there needs to be an established timeline.

At workshops, the Energy Division proposed a RA records retention policy. Staff proposed that the Energy Division shall keep all RA filings and related materials for three calendar years after the end of the compliance year. Staff proposed to generally destroy records past their retention date, with discretion to retain records for statistical, enforcement or other purposes.

No party commented on this proposal. We see this proposal as reasonable as an administrative part of running the RA program. We adopt the Energy Division's RA records retention policy.

4.3.5. Local Area Substitution

D.06-06-064 at 42, established the requirement that LSE must show in their compliance filings all their local RA capacity in order to avoid unnecessary over-procurement.

In the CAISO's tariff for the SCP, RA resources must be "available" for a certain percentage of the peak hours in a certain month or they will be subject to unavailability charges. The availability of unit may be reduced by a forced outage but not by a scheduled outage. A provision of the tariff allows for LSEs to lessen the burden of financial impacts, due to forced outages, by substituting capacity from non-RA units. Additionally, the tariff includes an additional requirement that if the resource is a local resource, the substitute unit must have equivalent characteristics to the RA unit on being replaced.

According to SCE, under the CAISO's SCP, RA resources are required to be available for a certain number of hours, or be subject to unavailability charges. For some of these resources within local areas, the LSE or the generator would have the ability to substitute and avoid those unavailability charges. Current RA rules require LSE's to list all of their contracted local resources in their filings, thereby making it impossible to substitute for local resources. SCE would give generators or LSEs that are subject to the reporting requirement the ability to substitute resources in this situation.

SCE proposes that the Commission eliminate the requirement that LSEs be required to show all their local resources in their year-ahead LCR showing, provided that any local resources that are listed on an LSE's year-ahead LCR filing be required to be included , if available, in that same LSE's monthly system filing. SCE claims it is unable to utilize CAISO's substitution rule because none of their local resources, which are under contract, qualify as non-RA. SCE argues that eliminating the requirement to show all local resources in the year-ahead filing, LSE's that already have an excess of local resources under contract will better be able to mitigate customer costs by eliminating unnecessary acquisition of additional local capacity, or avoiding the imposition of unavailability charges.

D.06-06-064 protects against unnecessary over-procurement. If an LSE that is long on its local RA is allowed to withhold the resources from the RA showing, then an LSE that is short on its local RA may have no access to the resources being held by the other LSE and may result in the CAISO assuming that additional local RA procurement is needed.

AReM proposes that in order to remedy SCE issue, the RA template can be changed to reflect an additional piece of information that marks the local resource as RA eligible.

The CAISO objected to SCE's proposal stating "To the extent that any procured RA resources are not included in the year-ahead showing, the ISO could be led to conclude that there is an individual and/or collective deficiency in meeting the local capacity requirements, which could result in ICPM procurement for a full year, with the cost allocated first to the individually short load serving entities and then the "collective" deficiency."[78]

SCE responded to the CAISO's concern by stating: "SCE is supportive of the Commission requiring LSEs to inform the CAISO of additional local resources under their control that they did not identify in their year-ahead local showing in the event the CAISO notifies market participants of local area capacity deficiency. If the CAISO accepts those resources to meet the local deficiency, those local resources would become (capital L) local RA resources and included in a supplemental LSE local RA filing"[79]

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[78] CAISO Comment on Phase 1 issues at 15.

[79] SCE comments on Phase 1 at 11.

We will not adopt SCE's proposal. At this time we do not agree that removing the current Commission rule that requires an LSE show all their local RA in all of their RA showings will provide the CAISO with adequate resources to ensure grid reliability. As SCE stated, there appears to be some inconsistency between the CAISO tariff on the SCP and the Commission Rules. In order to address this issue in the most effective matter some more thought needs to occur on how this rule would interact with a local true up methodology.

5. 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.

6. Assignment of Proceeding

Michael R. Peevey 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 2011 LCR study were discussed and recommended in a CAISO stakeholder meeting, and they generally mirror those used in the 2007 through 2010 LCR studies.

2. The SCP is an attempt to reduce transactions costs associated with buying, selling, and trading capacity to meet RA requirements. In order to meet this goal, the SCP seeks to standardize the obligations of RA providers and other related terms of RA contracts. As implemented to date, the SCP places contract terms relating to availability standards and penalties in Section 40.9 of the CAISO Tariff.

3. The FERC approved the existing SCP on June 28, 2009. In that order, FERC directed the CAISO to work toward extending the SCP to currently exempt

resources. At this time, certain resources whose QC are determined based on historical data (including QF resources) and demand response resources are exempt from the SCP.

4. A process for local true-up of RA capacity was adopted in D.10-03-022 for 2010 only.

5. One of the purposes of the LCR studies is to identify the local constraints in the coming year. The 2011 LCR results of the "other PG&E areas" shows that there still are a limited amount of resources in those areas.

6. Previous resource adequacy decisions, including D.06-06-064, provided that an LSE cannot be required to procure capacity that does not exist, in situations where the local area resource need is higher than existing generation capacity. This "blanket waiver" has been continued year to year.

7. In order for the SCP to be fully functional, it must be available as a commercially-viable product that LSEs can purchase, consistent with the counting rules developed by the Commission. This requires turning the SCP into a fungible product that is easily commercially traded.

8. Demand Response resources are currently exempt from the SCP.

9. A QC Report provided by the Energy Division in workshops led to parties' comments, and formed the basis for the Commission to consider a Qualifying Capacity Methodology Manual.

10. The classification methodology proposed by the Energy Division in Section 3.1 of the QC Report allows for case by case determination of the dispatchability classification of individual resources, including CHP. The Energy Division's proposal allows the specific details of a resource's operational characteristics, both physical and contractual, to be considered in its classification.

11. Because the SCP availability standard already applies to dispatchable resources, the resource owner and scheduling coordinator have proper incentives to classify the resource appropriately.

12. The Energy Division's proposals to measure the QC of new non-dispatchable resources using an approximation based on existing non-dispatchable resources, and to modify the measurement hours, provide a reasonable approach to address a gap in previously adopted rules.

13. The CAC proposal to calculate NQC on a monthly basis as opposed to a summer-months average for the entire year, as applied to all non-dispatchable resources, is reasonable.

14. Counting rules for all resources should be operator-neutral, and should only differentiate between resources based on the operational characteristics of the resources. However, in some cases, especially with demand response, operational characteristics may be substantially correlated with the characteristics of the resource operator.

15. Line losses are included in the load forecast used for RA requirements. Demand response resources provide a means of balancing supply and demand without accruing line losses.

16. The entire structure of the local RA program uses summer peak values for not only load forecasts, but all supply resources. This conservative approach provides a significant margin of safety in the off-peak months.

17. The existing RA procurement penalty structure provides no guidance as to what happens if the LSE does not replace capacity within 10 business days after notification.

18. LSEs currently submit a month ahead forecast 60 days prior to the month they are forecasting. The monthly load forecast is submitted 30 days before the

filing of the Month-Ahead RA showing. This monthly load forecast is used as part of the month-ahead compliance check because it may change the load forecast which in turn changes the RA obligation. In some cases, LSEs have filed updates to their load forecasts after they file their month-ahead RA showing.

19. Currently there is no established timeline for the RA record retention process.

20. It is not clear that removing the current Commission rule that requires an LSE show all its local RA in all of its RA showings will provide the CAISO with adequate resources to ensure grid reliability.

Conclusions of Law

1. The CAISO's 2011 LCR study should be approved as the basis for establishing local procurement obligations for 2011 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. There is a need for further discussion and record development regarding proposals for a local true-up methodology for 2011 and beyond, once there is sufficient experience gathered with the local RA True up mechanism adopted in D.10-03-022.

4. Given the local resource constraints identified by the CAISO in the "other PG&E" local areas and consequent market power concerns, it is reasonable to keep the local areas aggregated for 2011.

5. There is no foreseeable situation where there will be no need for the "blanket waiver". The "blanket waiver" should be adopted for 2011 and beyond.

6. The SCP should not be made mandatory at this time.

7. While in theory the SCP ultimately should be extended to DR resources, there is no viable proposal to effectuate this change at this time.

8. A Qualifying Capacity Methodology Manual (QC Methodology Manual) should be adopted.

9. The Energy Division's proposal to allow for case by case determination of the dispatchability classification of individual resources should be adopted as part of the QC Methodology Manual.

10. The Energy Division's proposals to measure the QC of new non-dispatchable resources using an approximation based on existing non-dispatchable resources, and to modify the measurement hours, should be approved as part of the QC Methodology Manual.

11. The CAC proposal to calculate NQC on a monthly basis as opposed to a summer-months average for the entire year, as applied to all non-dispatchable resources, should be approved as part of the QC Methodology Manual.

12. Counting rules for all resources should be operator-neutral, and should only differentiate between resources based on the operational characteristics of the resources. Fairness requires that we decline to differentiate based on the identity of the operator.

13. It is reasonable that dispatchable DR resources with financial incentives for availability and performance comparable to those of dispatchable supply resources should be able to receive QC with a comparable testing methodology. However, unless and until it is demonstrated to us, in this or a future RA proceeding, that such a DR resource exists, we will retain our current policy that the LIPs are used to establish the QC of DR resources to the maximum extent possible.

14. DR resources should receive the benefit of avoiding line losses in calculating RA values.

15. SCE's proposal to value line losses for DR resources in calculating RA values is reasonable.

16. The current treatment of AC Cycling programs is consistent with the larger local RA program and should continue.

17. It is reasonable to both provide an incentive for timely replacement of RA procurement capacity and to provide a clear penalty if this does not occur.

18. The Energy Division's proposal that LSEs may, at the discretion of CEC staff, file changes to their load forecasts up to 25 days before the due date of the month-ahead compliance filings, is reasonable.

19. The Energy Division's proposal to keep all RA filings and related materials for three calendar years after the end of the compliance year is reasonable.

O R D E R

IT IS ORDERED that:

1. The California Independent System Operator's final 2011 Local Capacity Technical Analysis Final Report and Study Results is adopted as the basis for establishing local procurement obligations for 2011 applicable to Commission-jurisdictional load-serving entities, as 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 *2011 Local Capacity Technical Analysis, Final Report and Study Results*, dated May 3, 2010, 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 2011 are as follows:

	2011 LCR Need Based on Category C with operating procedure		
Local Area Name	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**
Humboldt	188	17	**205**
North Coast / North Bay	734	0	**734**
Sierra	1510	572	**2082**
Stockton	459	223	**682**
Greater Bay	4804	74	**4878**
Greater Fresno	2444	4	**2448**
Kern	434	13	**447**
LA Basin	10589	0	**10589**
Big Creek/ Ventura	2786	0	**2786**
San Diego	3146	61	**3207**
Total	**27094**	**964**	**28058**

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

4. The assigned Administrative Law Judge in this proceeding shall take comments on a re-evaluation of the 2010 resource adequacy local true-up adopted in Decision 10-03-022 in order to consider implementing a resource adequacy local true-up or reallocation methodology for 2011 and beyond.

5. While we may, at our discretion, revisit the issue in the future, the "blanket waiver" rule that an LSE cannot be required to procure capacity that does not exist, in situations where the local area resource need is higher than existing generation capacity, is made permanent:

   a. The "blanket waiver" rule that an LSE cannot be required to procure capacity that does not exist, in situations where the local area resource need is higher than existing generation capacity, is adopted for 2011 and beyond.

   b. The Qualifying Capacity Methodology Manual in Appendix B to this decision is adopted as part of the resource adequacy program. The Energy Division shall use the Manual to calculate a 2011 net qualifying capacity list and post the results on the Energy Division's website. Each load-serving entity shall use net qualifying capacity values established according to the manual along with relevant allocations for resource adequacy (RA) credit to fulfill its resource adequacy obligation.

   c. Line losses avoided by demand response (DR) resources shall be valued for the purposes of resource adequacy calculations as follows:

      DR RA Value = 1.15 * DR Load Impact * (1.00/(1.00 – transmission and distribution (T&D) Line Loss Rate)) *where*, T&D Line Loss Rate = 3% + IOU-specific Distribution Loss Factors.

   d. Full year local resource adequacy credit for Air Conditioner Cycling programs shall continue.

   e. The Energy Division shall keep all resource adequacy filings and related materials for three calendar years after the end of the compliance year. The Energy Division shall generally destroy records past their retention date, but may retain records for statistical, enforcement or other purposes.

   f. Load-serving entities may, at the discretion of the California Energy Commission staff, file changes to their load forecasts up to 25 days before the due date of the month-ahead compliance filings.

g. The following penalty structure for resource adequacy procurement deficiencies is adopted for violations which occur after the date of this decision:

	Small Procurement Deficiency	System Procurement Deficiency	Local Procurement Deficiency
Replaced within five-business days of the date of notification	$1,500 first incident in calendar year; $3,000 for each incident thereafter in a calendar year	$3.33/kilowatt (kW)-month	$3.33/kW-month
Replaced after five-business days from the date of notification or not replaced	LSE pays the applicable System or local RA penalty for the deficiency	$6.66/kW-month	$6.66/kW-month

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

This order is effective today.

Dated _____________________________, at San Francisco, California.

APPENDIX A

Load-Serving Entities as Defined in Section 380(j)

Electrical Corporations

Brian Cherry (39)
Director, Regulatory Relations
Pacific Gas and Electric Company
P. O. Box 770000, B10C
San Francisco, CA 94177

Steve Rahon (902)
Director, Tariff & Regulatory Accounts
San Diego Gas & Electric Company
8330 Century Park Court, CP32C
San Diego, CA 92123-1548

Akbar Jazayeiri (338)
Director of Revenue & Tariffs
Southern California Edison Company
P. O. Box 800
2241 Walnut Grove Avenue
Rosemead, CA 91770

Electric Service Providers

Inger Goodman
Commerce Energy, Inc. (1092)
575 Anton Boulevard, Suite 650
Costa Mesa, CA 92626
igoodman@commerceenergy.com

Ron Cerniglia
Direct Energy Services, LLC (1341)
12 Greenway Plaza, Suite 600
Houston, TX 77046
ron.cerniglia@directenergy.com

Kerry Hughes
Direct Energy Business (1351)
7220 Avenida Encinas, Suite 120
Carlsbad, CA 92009
customerrelations@directenergy.com

Victor Gonzales
Constellation NewEnergy, Inc. (1359)
111 Market Place, Suite 500
Baltimore, MD 21202
victor.m.gonzalez@constellation.com

Kevin Boudreaux
Calpine PowerAmerica-CA, LLC (1362)
3875 Hopyard Road, Suite 345
Pleasanton, CA 94588-8558
kevin.boudreaux@calpine.com

Drake Welch
Sempra Energy Solutions (1364)
401 West A Street, Suite 500
San Diego, CA 92101-3017
dwelch@semprasolutions.com

Thomas Darton
Pilot Power Group, Inc. (1365)
8910 University Center Lane, Suite 520
San Diego, CA 92122
tdarton@pilotpowergroup.com

Rick C. Noger
Praxair Plainfield, Inc. (1370)
2711 Centerville Road, Suite 400
Wilmington, DE 19808
rick_noger@praxair.com

Jenny Zyak
Liberty Power Holdings LLC (1371)
1901 W. Cypress Creek Road, Suite 600

Fort Lauderdale, FL 33309
jzyak@libertypowercorp.com

Jenny Zyak
Liberty Power Delaware LLC (1372)
1901 W. Cypress Creek Road, Suite 600
Fort Lauderdale, FL 33309
jzak@libertypowercorp.com

Michael Mazur
3 Phases Electrical Consulting (1373)
2100 Sepulveda Blvd., Suite 37
Manhattan Beach, CA 90266
energy@3phasesrenewables.com

Marcie Milner
Shell Energy (1374)
4445 Eastgate Mall, Suite 100
San Diego, CA 92121
martin.kadillak@shell.com

Any electric service provider that, subsequent to the date of the order instituting this rulemaking, becomes registered to provide services within the service territory of one or more of the respondent electrical corporations through direct access transactions shall, upon such registration, become a respondent to this proceeding. Any electric service provider respondent whose registration is cancelled during the course of this proceeding shall, upon confirmation of such cancellation by the Energy Division, cease to be a respondent to this proceeding.

Community Choice Aggregators

Marin Energy Authority
John Dalessi
Staff Consultant
916-631-3210
jdalessi@navigantconsulting.com
3100 Zinfandel Drive, Ste. 600
Rancho Cordova, CA 95670

Any community choice aggregator that, subsequent to the date of the order instituting this rulemaking, files an implementation plan or becomes registered to provide services within the service territory of one or more of the respondent electrical corporations through community choice aggregation transactions shall, upon such filing or registration, become a respondent to this proceeding. Any community choice aggregator respondent that withdraws its implementation plan or whose registration is cancelled during the course of this proceeding shall, upon confirmation of such withdrawal or cancellation by the Energy Division, cease to be a respondent to this proceeding.

(END OF APPENDIX A)

APPENDIX B

Qualifying Capacity Methodology Manual

1. Table of Contents

2. Introduction

This manual describes the current net qualifying capacity (NQC) counting rules of the California Public Utilities Commission (CPUC) and the methodology for implementing these rules. Each year, CPUC staff works with the California Energy Resources Conservation and Development Commission (Energy Commission) and California Independent System Operator (California ISO) to publish an NQC list which describes the amount of capacity that can be counted from each resource toward meeting Resource Adequacy (RA) requirements in the CPUC's RA program. The qualifying capacity (QC) of each resource is set by the methodologies described in this document; then if it's QC is not fully deliverable to aggregate California ISO load, it is adjusted to its deliverable capacity resulting in its NQC. For purposes of this report, the term 'resource' is used to refer to a generator that has a resource ID on the Master CAISO Control Area Generation Capability List (Generation Capability List)[1] or a demand response program which may not have a resource ID.

2.1. Guide to this Document

Sections 3 through 6 describe issues relevant to a variety of resource classifications. Sections 7 through 10 provide details on the specific calculation methodologies for each of the resource types described in Section 3, Resource Classification. Section 4, Deliverability describes California ISO's methodology for assessing the deliverability of generating resources and how Deliverability Assessment impacts NQC. Section 5 lists certain data conventions used in calculating QC. Section 6 discusses the treatment of outages in QC calculations.

The appendices to this report are presented in a separate file.

3. Resource Classification

CPUC staff coordinates with California ISO and Energy Commission staff each year to group resources, by California ISO scheduling resource ID (CAISO ID), into the classifications described below. Classification is based on the dispatchability and technology type of the resource. Primary guidance comes from the most recent available Generation Capability List. Classification for QC calculation does not consider Qualifying Facility status. Demand response

[1] http://www.caiso.com/14d4/14d4c4ff59780.html.

resources are not listed on the Generation Capability List; these resources are addressed in Section 10.

First, some resources are selected and classified according to the "ISO Classification" column. Resources listed as wind are classified as wind, and solar resources are classified as solar. The wind and solar classifications receive QC according to the methodology described in Section 8. Resources listed as hydro are classified as hydro resources. Hydro resources are sub-classified by dispatchability, as described below. Each year, Energy Division and California ISO publish a preliminary NQC list of all resources, including the proposed classification of each resource. Resource owners and Scheduling Coordinators (SCs) may suggest changes to the classification of their resources; stakeholders suggesting a change should provide appropriate support for their proposed change such as confirmation from the SC that the resource is dispatchable. On this preliminary list, hydro and other remaining resources are grouped according to dispatchability. Hydro resources may be listed as either "dispatchable hydro" or "non-dispatchable hydro." Hydro resources that are dispatchable by the SC or California ISO are classified as dispatchable hydro. The remaining resources (i.e. resources that are not demand response, wind, solar, or hydro) are also grouped by dispatchability. Resources that are dispatchable by the SC or California ISO are classified as dispatchable generation. Dispatchable generation resources including dispatchable hydro resources receive QC according to the methodology described in Section 7. This classification includes a variety of technologies: steam turbines; combustion turbines; combined cycles; reciprocating engines; and dispatchable combined heat and power (CHP), biomass and geothermal. Again, status as a use limited resource does not prevent a unit from being classified as dispatchable.

Finally, the remaining resources are classified as other non-dispatchable resources. Non-dispatchable hydro and other non-dispatchable resources receive QC according to the methodology described in Section 9.

4. Deliverability

Deliverability is the ability of the output of a generating resource to be delivered to aggregate load. The only difference between QC and NQC is the deliverability of the resource to aggregate California ISO load. If a resource's QC exceeds its deliverable capacity as determined by California ISO Deliverability Assessments, its NQC is adjusted to its deliverable capacity. In many cases, a resource is fully deliverable and there is no difference between QC and NQC.

California ISO assesses the deliverability of new and existing resources two to three times per year; a Deliverability Assessment is a required part of the Large Generator Interconnection Procedures (LGIP).[2] Existing resources retain priority for deliverability over new resources and resources are not expected[3] to lose deliverability rights unless the resource is unable to produce its deliverable capacity for at least three consecutive years. The deliverability study provides new resources with information to understand which network upgrades are necessary to achieve full deliverability.

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[2] See Appendix U of the California ISO Tariff: http://www.caiso.com/2471/2471994c26350.pdf. See also: Section 5.1.3.4 of CAISO's Business Practice Manual for Reliability Requirements: https://bpm.caiso.com/bpm/bpm/version/000000000000011.

[3] The exception to this rule is reduction in deliverability caused by any degradations of the transmission system which are not repaired promptly, for example due to fires or other force majeure events.

The ability of the output from a new generation project and existing generation to be delivered to aggregate load within California ISO during a resource shortage condition is evaluated pursuant to the ISO's LGIP and the California ISO Deliverability Assessment Methodology posted on the California ISO's website.[4]

The California ISO Tariff defines a generation project's deliverability as one of two discrete states: Full Capacity Deliverability Status and Energy-Only Deliverability Status. The NQC value of any Energy-Only facility is deemed to be zero.[5] Therefore, a generation resource's Deliverability Study Value is typically either 100% or 0% of its QC. However, it is possible that a very few projects that submitted interconnection requests prior to the reformation of the LGIP could have a deliverability level between 100% and 0%. There is also a remote possibility that the deliverability of existing resources could degrade substantially below 100% deliverable and as a result their deliverability level would need to be reduced accordingly. As of August 6, 2009, all generation resources were deliverable to 100% of their QC value. However, at that time, there were approximately 10,000 MW of energy only interconnection requests in the current California ISO interconnection queue. The California ISO Tariff defines Energy-Only connection resources to have an NQC of zero. Therefore, it is likely that, as these resources achieve commercial operation, many of them will have an NQC equal to zero.

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4 http://www.caiso.com/23d7/23d7e41c14580.pdf.

5 CAISO Tariff Appendix A, Fourth Replacement Volume No. 2, Sheet No. 863: http://www.caiso.com/2471/2471974a121c0.pdf.

The base case for the deliverability study is updated each year. Deliverability studies model peak demand periods and assume that all generating resources are dispatched to meet demand. The base case also assumes that sufficient generation is available within load pockets. Dispatch and outage contingency scenarios are also studied. Generation costs are not considered in the deliverability studies. A finding of deliverability does not ensure that a resource will not experience congestion, especially during non-peak periods. The deliverability study models a five-year planning horizon.

Not all new resources use the LGIP. Some resources connected to the transmission system with nameplate capacity 20 MW or less use the Small Generator Interconnection Procedure (SGIP). The SGIP does not include a Deliverability Assessment and resources that use SGIP have an NQC equal to zero.[6] Other small resources that are connected to the distribution system may use a Small Generator Interconnection Agreement (SGIA) with the distribution system owner.[7] These SGIAs include deliverability assessments which are accepted by California ISO. Therefore, these resources can be deliverable up to 100% their QC.

5. Data Conventions

This section lists certain conventions used by the staffs of the CPUC, California ISO, and Energy Commission in dealing with the data in the QC calculation process:

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[6] See Appendix S to the California ISO Tariff: http://www.caiso.com/2471/247198fe24690.pdf.

[7] SGIA interconnections use the Wholesale Distribution Access Tariff (WDAT).

- For wind, solar, and other non-dispatchable resources, historical production data is used. This data is obtained by subpoena from CPUC to California ISO; CPUC subpoenas data for specific resource IDs in these classifications from the classification list. CPUC subpoenas hourly "Actual Settlement Quality Meter Data" which describes the production profile for each resource. The production is measured in MWh produced per hour. This data represents the average generation (MW) over each hour and does not provide any information about intra-hour variation in generation.
- New wind, solar, and other non-dispatchable resources are considered to begin operation in the first month the resource operated before the 15th day. A resource that began producing on the 16th (or later) day of a month is considered to begin operation during the following month. The first positive values in the Actual Settlement Quality Meter Data are the sign that a resource began producing. Under this convention, no distinction is made between zero values due to a discontinuation of operation versus zero production during the normal course of operation (e.g. due to lack of fuel such as wind).

6. Outages and QC Calculation

This section describes how past outages may impact the QC of some resources; it does not describe how California ISO schedules and approves outages or how SCs should report outages.

Scheduled outages greater than 25% of days in a month reduce the amount of NQC that a resource can count for RA during that month; this rule is referred to as the scheduled outage criterion.[8] For resource types whose NQC is derived

[8] The scheduled outage criterion was adopted by D.06-07-031. For more information, see Section 13 of the 2010 RA Guide: http://www.cpuc.ca.gov/NR/rdonlyres/14DFD39E-40C6-4FAF-8C36-38F8708BC23A/0/RAGuide2010.doc.

from historical data,[9] proxy data is generated to replace data during any scheduled outages of sufficient duration to trigger the scheduled outage criterion[10] and for any forced outage, non-ambient derate, or temperature-related ambient derate. These resource classifications include non-dispatchable wind, solar, biomass, CHP, and geothermal resources. Outages or derates that only partially reduce the output of the resource are treated the same as outages or derates with zero output; therefore, production during an outage or derate has no impact on the calculated QC.

In order to generate the set of outages or derates to be "corrected" California ISO retrieves data from Scheduling and Logging for ISO of California (SLIC) system.[11] First, CPUC provides a list of resources to California ISO to include in its query. Then, for each calendar month within the three calendar years used for calculations, California ISO queries SLIC for all outages of outage types:

- **"Planned"** with a duration greater than seven days,
- "**Forced**" of any duration, or
- "**Ambient**" of any duration, with the "Ambient Not Due to Temperature" attribute not selected.

Other criteria for the data query are:

- **Process Status:** "APPROVED", "OUT", "REQUESTED" , "SCHEDULED", or "INSERVICE" (INSERVICE status is necessary to pull historical data since status changes to INSERVICE after outage is over)

[9] See Sections 8 and 9.

[10] D.09-06-028, pg 29.

[11] For more information about SLIC, see: http://www.caiso.com/docs/2005/10/28/2005102810475421112.html.

- **Resource type:** "GENERATOR"
- **Outage mode:** "DERATE"

After receiving the description of the outages and derates from California ISO, the CPUC and Energy Commission remove the data during the outages and develop replacement proxy data. For each outage or derate hour, the values for the same hour on the same calendar day for other years in the data set are averaged. This average value is inserted as the proxy value. The average includes all values in the data set, for the appropriate day and hour, which are not marked as an outage or derate. Therefore, if there were overlapping outages or derates in two out of three years (i.e. outages during two years covered some of the same hours), all three years would receive the value of the remaining year for the hours marked as outage or derate during both years. If an outage or derate exists at the same time period for all three years, that hour is excluded from the QC calculation.[12]

Table 1 shows an example for this calculation. The resource had an outage in year 3 including all hours of March 7. Note that the production values during the outage (i.e. in year 3) do not affect the proxy values.

Date	Hour	Year 1 (MWh)	Year 2 (MWh)	Year 3 (MWh)	Average (MWh), Years 1 - 2	Average (MWh), Years 1 -3	Proxy Value (MWh) - Year 3
7-Mar	1	50	53	16	51.5	39.7	51.5
7-Mar	2	51	54	15	52.5	40	52.5
7-Mar	3	50	52	17	51	39.7	51
7-Mar	4	52	50	16	51	39.3	51
7-Mar	5	55	53	17	54	41.7	54
7-Mar	6	60	63	18	61.5	47	61.5
7-Mar	7	70	65	16	67.5	50.3	67.5

[12] See **Error! Reference source not found.**

7-Mar	8	71	70	17	70.5	52.7	70.5
7-Mar	9	72	75	18	73.5	55	73.5
7-Mar	10	72	74	17	73	54.3	73
7-Mar	11	74	72	16	73	54	73
7-Mar	12	74	73	20	73.5	55.7	73.5
7-Mar	13	75	77	19	76	57	76
7-Mar	14	74	76	18	75	56	75
7-Mar	15	76	72	19	74	55.7	74
7-Mar	16	75	73	19	74	55.7	74
7-Mar	17	75	78	18	76.5	57	76.5
7-Mar	18	74	75	20	74.5	56.3	74.5
7-Mar	19	70	73	19	71.5	54	71.5
7-Mar	20	68	69	18	68.5	51.7	68.5
7-Mar	21	65	67	19	66	50.3	66
7-Mar	22	63	65	18	64	48.7	64
7-Mar	23	60	62	18	61	46.7	61
7-Mar	24	58	59	18	58.5	45	58.5

Table 1. Example of Proxy Data

7. Dispatchable Generation

Dispatchable generation resources receive NQC values based on their available capacity,[13] subject to the checks described in Section 4, Deliverability. The Scheduling Coordinator (SC) of the resource submits a proposed QC value to the California ISO, along with a reference to the resource's most recent maximum power plant output (PMax) test[14] that is in California ISO's master file. This information is submitted to California ISO in a standard format;[15] California ISO checks the submitted value for consistency with the PMax and

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[13] See also, Section 5 of CAISO's Business Practice Manual for Reliability Requirements: https://bpm.caiso.com/bpm/bpm/version/000000000000011.

[14] California ISO coordinates with SCs for resources to schedule PMax tests at a time selected by the SC. Generally, SCs select the timing of a PMax test to demonstrate output of the resource at or near its maximum possible output.

[15] See http://www.caiso.com/1796/179697c864850.xls.

maximum deliverable capacity. If the proposed QC value is less than or equal to the PMax and the maximum deliverable capacity, it is accepted for the NQC value. If not, the previous NQC value is retained. The SC may coordinate with California ISO to update the PMax test or supply other information as requested by California ISO in order to determine an acceptable change to NQC. The SC may use this process to update the QC from time to time. At the time each compliance year's NQC list is published, California ISO checks that each NQC is less than or equal to the most recent PMax for the resource.

8. Wind and Solar

The QC of wind and solar resources is based on an exceedance methodology.[16] The exceedance approach measures the minimum amount of generation produced by the resource in a certain percentage of included hours. For example, the mathematical concept of "median" is a special case of the exceedance concept, with the exceedance level set to 50%. The exceedance level used to calculate the QC of wind and solar resources is 70%. Another way to describe the exceedance level is that the 70% exceedance level of a resource's production profile is the maximum generation amount that it produces at least 70% of the time. The exceedance concept is depicted in Figure 1; while the median is not used in the wind and solar QC calculation, it is included in the diagram to provide context to the 70% exceedance. The 70% exceedance value is shown as a blue horizontal line and the median is a purple horizontal line.

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[16] Adopted in D.09-06-028, Appendix C.

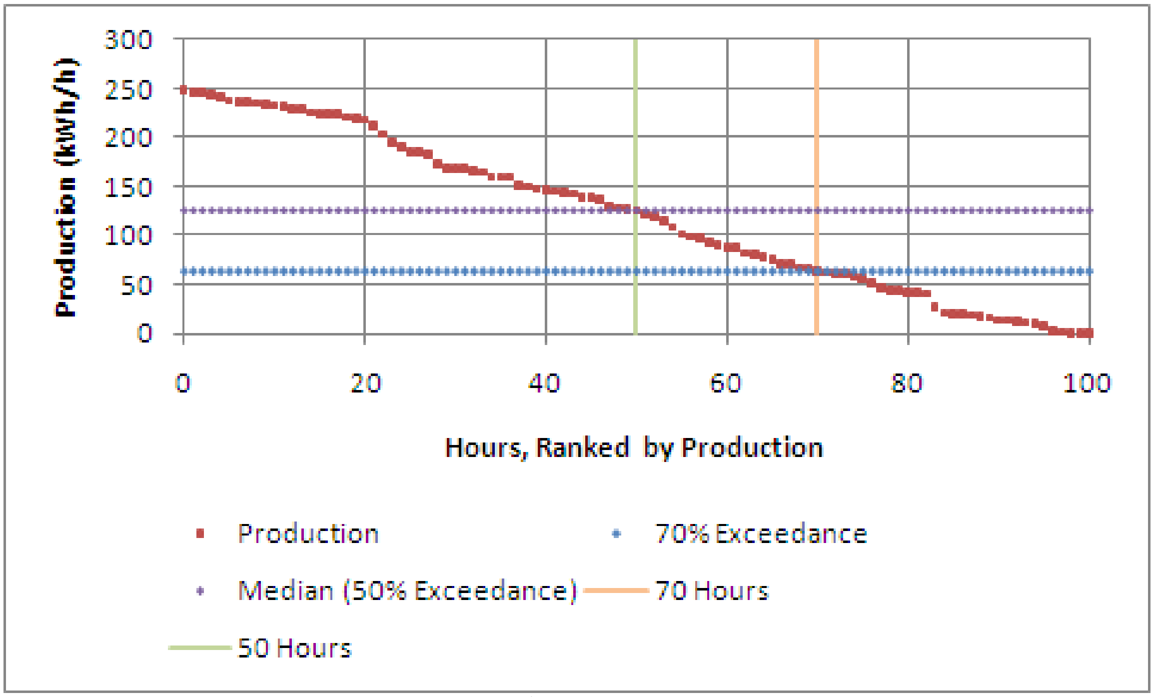

Figure 1. Conceptual Diagram of Exceedance[17]

Intuitively, the exceedance calculation ranks all of the included hours by production and draws the initial QC from the value 70% of the way through the ranking (30% from the lowest value). In practice, this could be achieved with the percentile function in Excel, but for QC calculations the Statistical Analysis Software® (SAS)[18] PROC UNIVARIATE routine is used.[19] Since in many cases, the precise 70th percentile falls between two values, interpolation between the two values surrounding the 70th percentile is needed. The average, weighted by

[17] The production profile in the figure is generated randomly and is not intended to represent any particular resource or classification of resources.

[18] For more information about SAS®, see http://www.sas.com/technologies/analytics/statistics/stat/index.html.

[19] See **Error! Reference source not found.**

proximity to the 70th percentile, of the two values is used.[20] In Figure 1, interpolation is not needed since there are exactly 100 values in the data set and the 70th percentile corresponds to a discrete value in the data.

The included hours for the wind and solar QC calculations are shown in Table 2. The included hours vary seasonally and are based on the time of system peak demand.

Jan–Mar, Nov and Dec:	HE17 - HE21[21] (4:00 p.m. - 9:00 p.m.)
Apr–Oct:	HE14 - HE18 (1:00 p.m. - 6:00 p.m.)

Table 2. Included Hours for QC Calculations

36 months of production data (Actual Settlement Quality Meter Data, as described in Section 4) are used for the QC calculation. Staff uses the three most recent years of complete data available (i.e. for 2009 QC values, 2005-2007 data). As noted below, most of the following steps are repeated for each of the 36 months; then the three years are averaged to result in 12 final monthly values.

The first step in calculating QC of wind and solar resources is to calculate the 70% exceedance for each time period. This is called the Initial QC. An initial QC is calculated for each resource for each of the 36 months.

$$InitialQC(MW) = 70\%Exceedance[UnitSpecificHourly\Pr oduction(MWh/h)]$$

Equation 1. Initial QC

Differences in production profiles across different individual wind or solar resources are called diversity. The exceedance of the sum of a diverse group of

[20] See the description of the PCTLDEF=1 at: http://support.sas.com/documentation/cdl/en/procstat/59629/HTML/default/procstat_univariate_sect028.htm.

[21] HE indicates "hour ending", or the 60 minutes that end at the numbered hour, in 24 hour time. For example, HE17 indicates the 60 minutes beginning at 16:00 (i.e. 4:00 p.m.) and ending at 16:59.

resources is always greater than or equal to the sum of the exceedances of the individual resources (i.e. the initial QCs). Any difference between the exceedance of the sum and the sum of the initial QCs is called the diversity benefit. The total benefit of diversity is the difference between the 70% exceedance of all wind and solar resources as a group and the sum of the initial QCs of all individual resources. The system diversity benefit is calculated for each of the 36 months.

$$SystemDiversityBenefit =$$
$$70\%Exceedance\left[\sum_{Units} Hourly\,\mathrm{Pr}\,oduction\right] - \sum_{Units} InitialQC$$

Equation 2. System Diversity Benefit

The benefits of resource diversity are allocated to all wind and solar resources on the basis of energy produced during included hours. Each resource's diversity share is calculated as the kWh produced during the included hours by that resource divided by the kWh produced by all wind and solar resources during the same time period. The resource specific diversity benefit is the product of the resource diversity share and the system diversity benefit. No resource may have a calculated QC that exceeds its maximum capacity (maximum capacity is the 1st percentile exceedance of the resources production during all hours of the month). Therefore, this process is repeated in "passes" (for each of the 36 months) until the entire system diversity benefit (for the month) is allocated to specific resources and no resources have calculated QC greater than maximum capacity. For the first pass, all resources are included, but in any passes after the first, only resources with calculated QCs from the previous pass that are less than maximum capacity. The resource diversity benefit is calculated for each resource for each of the 36 months. It is possible that some of the 36 months may require multiple passes while other months require only a single pass.

$$\mathrm{Re}\,sourceDiversityShare_{Pass} = \sum_{Hours} \mathrm{Pr}\,oduction \Bigg/ \sum_{Hours}\left(\sum_{\mathrm{Re}\,sourcesIncludedInPass} \mathrm{Pr}\,oduction\right)$$

Equation 3. Resource Diversity Share

$$\mathrm{Re}\,sourceDiversityBenefit_{Pass} = SystemDiversityBenefit_{Pass} * \mathrm{Re}\,sourceDiversityShare_{Pass}$$

Equation 4. Resource Diversity Benefit

The sum of a resource diversity benefit and a corresponding initial QC is referred to as a calculated QC. As noted above, the calculated QC cannot exceed the maximum capacity. If the calculated QC would exceed the maximum capacity, the calculated QC is set to the maximum capacity and the amount of the resource diversity benefit that is beyond the maximum capacity is considered the residual resource diversity benefit. The residual resource diversity benefits of all resources are summed to become the system diversity benefit used in the following pass. For the first pass, the initial QCs are used in **Error! Reference source not found.** for the calculated QC of the previous pass (i.e. $\mathrm{CalculatedQC}_{\mathrm{Pass-1}}$).

$$\begin{aligned}
&If:\\
&CalculatedQC_{Pass-1} + \mathrm{Re}\,sourceDiversityBenefit_{Pass} \le MaximumCapacity,\\
&Then:\\
&CalculatedQC_{Pass} = \mathrm{Re}\,sourceDiversityBenefit_{Pass} + CalculatedQC_{Pass-1}\\
&Else:\\
&CalculatedQC_{Pass} = MaximumCapacity,\\
&And:\\
&\mathrm{Re}\,sidual\,\mathrm{Re}\,sourceDiversityBenefit_{Pass} =\\
&CalculatedQC_{Pass-1} + \mathrm{Re}\,sourceDivesityBenefit_{pass} - MaximumCapacity
\end{aligned}$$

Equation 5. Calculated QC for Existing Resources

$$SystemDiversityBenefit_{Pass+1} = \sum_{\mathrm{Re}\,sources} \mathrm{Re}\,sidual\,\mathrm{Re}\,sourceDiversityBenefit_{Pass}$$

Equation 6. System Diversity Benefit for Pass 2 and any later Passes

If **Error! Reference source not found.** yields a positive system diversity benefit, a new pass is initiated, beginning with **Error! Reference source not found.**. Only the resources which have a calculated QC less than maximum capacity from the just completed pass are included in the calculations during the new pass.

After the proceeding steps are completed, each existing resource has 36 initial QCs and 36 corresponding resource diversity benefits. Therefore, each existing resource has 36 calculated QCs.New resources, which do not have the complete 36 months of data, have calculated QCs for any month(s) which they do have data. For each month that a new wind (solar) resource does not have an initial QC and resource diversity benefit, it receives a calculated QC value based on the performance (i.e. calculated QC) of all wind (solar) resources that existed during that month. This value is the average calculated QC as a fraction of the available capacity of all of the wind (solar) resources in that month. The available capacity is calculated as the 1st percentile exceedance value of all hours in the month. This value is multiplied by the Net Dependable Capacity (NDC) of the new resource, as recorded in the Generation Capability List.

$$CalculatedQC_{New\,\mathrm{Re}\,source} = NDC_{New\,\mathrm{Re}\,source} * \left(\sum_{Existing\,\mathrm{Re}\,sources} CalculatedQC \Big/ \sum_{Existing\,\mathrm{Re}\,sources} 1\%Exceedance\left[\mathrm{Pr}\,oduction\right] \right)$$

Equation 7. Proposed Calculated QC for New Wind (Solar) Resources

Now each and every wind and solar resource has 36 QC calculated values. To calculate the final 12 monthly QC values, the three corresponding months are averaged for each resource. For example, the three January values are averaged to calculate the final January QC.

$$FinalQC_{SpecificMonth} = \sum_{SpecificMonth} CalculatedQC \Big/ 3$$

Equation 8. Final QC

The preceding description is a conceptual approach to the calculations of wind and solar QC values. In practice, the calculations are performed in a SAS® program.

9. Non-Dispatchable Resources

Non-dispatchable generation resources not described in previous sections receive monthly QC values based on a three-year rolling average of production during certain hours, shown in Table 2. The three most recent years of available data are used; for example, 2010 QC is calculated based on 2006-2008 data. Historical production data is adjusted for scheduled outages as described in Section 6. SAS® code for these calculations is included in the Appendix.

For this calculation, each monthly value is calculated as an average of the production during the specified hours. The 36 monthly average values are calculated as:

$$Average_{Month}(MW) = \frac{\sum_{Month} \Pr oduction(MWh)}{\sum_{Month} Hours(h)}$$

Equation 9. Monthly Average Production for Non-Dispatchable Resources

Then, the monthly values are averaged together for all (up to three) years of available data to calculate the final QC for each month.

$$FinalQC_{Month} = \frac{1}{\{NumberOfYearsOfData_{Month}\}} * \sum_{AllYearsOfData} Average_{Month}$$

Equation 10. Final QC of Non-Dispatchable Resources

New non-dispatchable resources with zero complete months of available data for any month shall receive QC for that month based on multiplying the resource's NDC by the average QC as a percent of NDC of all existing resources in this classification.

$$MonthlyQC_{\text{Re}\,source} = NDC_{\text{Re}\,source} * \frac{\sum_{ExistingNon-Dispatchable\,\text{Re}\,sources} MonthlyQC}{\sum_{ExistingNon-Dispatchable\,\text{Re}\,sources} NDC}$$

Equation 11. QC for Non-Dispatchable Resources with no Available Data

10. Demand Response (DR)

In D.09-06-028, CPUC directed that the QC of DR resources will be based on the Load Impact Protocols (LIPs) adopted by D.08-04-050.[22] However, the LIPs provide far more detailed information than 12 monthly QC values. The discussion of the LIPs in this Manual does not in anyway impact the requirements of any previous decision in the DR proceedings or any other uses of the LIPs besides QC calculations.

The LIPs must be followed by the entity (typically the Investor Owned Utility{IOU}) requesting that the DR program be eligible for meeting RA Requirements. That entity must work with Energy Division staff to provide at least the LIP information described below for the DR resource to receive QC values. The following table summarizes the use of LIPs for QC demonstration. Event based resources (i.e. AC cycling) are DR programs that only operate when a specific event is called while non-event based resources (i.e. Time-Of-Use rates or permanent load shifting) operate each day, regardless of whether or not a DR event is “called”. Page and section references in this table refer to Attachment A to D.08-04-050.

[22] The LIPs are detailed in Appendix A to D.08-04-050; http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/81979.PDF.

The monthly QC of a DR resource is the average expected (ex ante) load impact measured over certain measurement hours. The measurement hours are:

RA Compliance Year	Hours	
2011	Hour Ending (HE) 15 to HE 18 (2:00 p.m. to 6:00 p.m.)	
2012 and beyond, except for programs that have a different, fixed operational period set by CPUC decision.	Jan–Mar, Nov and Dec: Apr–Oct:	HE 17 to HE 21 (4:00 p.m. - 9:00 p.m.) HE 14 to HE 18 (1:00 p.m. - 6:00 p.m.)

Table 3. Measurement Hours for DR

The hourly estimates for each of these hours from the LIP data are averaged together. These hourly estimates must be provided according to protocols 17, 21, 22, and 23. Other protocols described in this table are required for supporting data and report formatting.

Resource Type	Load Impact Protocols Required
Event Based Resources. Example IOU programs: CPP CBP DBP AC Cycling OBMC	**<u>Ex Post for Event Based Resources</u>** Protocol 7 requires impact estimates be reported in a table format. Uncertainty adjustments are not needed in the table. Protocol 8 requires reporting for the average across all participants notified on a average event day over the evaluation period. Only the hourly load drop across participants notified on an average event day is required; no need to provide the following details: • Each day on which an event was called; • The average event day over the evaluation period • For the average across all participants notified on each day on which an event was called; • For the total of all participants notified on each day on which an event was called. Protocol 10 requires regression based methods (read section 4.2.2, pg 60 for an overview of regression analysis). Any suppliers choosing not to use

	regression as described in Protocol 10 *must* file an evaluation plan (Protocols 1-3) well in advance of the QC demonstration deadline.[23] **<u>Ex Ante for Event Based Resources</u>** Protocol 17 requires that ex ante estimates should be informed by ex post whenever possible. Protocol 21 requires impact estimates be reported in a table format. Uncertainty adjustments are not needed in the table. Protocol 22 requires the use of 1-in-2 weather year for the monthly system peak day. The 1-in-10 weather year, typical event day, or an average weekday for each month are not needed for QC calculation. Protocol 23 requires ex ante estimates be based on regression methodologies (read section 6.2, pg 98 for guidance). **<u>Portfolio Impacts, if Required</u>** Protocol 24 describes methodology for estimating the impacts of multiple DR programs within a portfolio. All DR resources whose participants also participate in other DR programs (potentially operated by other entities) must follow Protocol 24; such resources should also submit an evaluation plan (Protocols 1-3). **<u>Sampling if Required</u>** Protocol 25 requires certain procedures to ensure that sampling bias is minimized. Protocol 25 is not anticipated to be required for most DR resources using LIPs only to demonstrate QC; DR resources with a small number of participating customers should provide data from *all* participants, obviating the need for sampling methodologies. For resources with enough participants to adopt a sampling methodology, an evaluation plan (Protocols 1-3) is required well in advance of the QC demonstration deadline. **<u>Reporting Protocols</u>** Protocol 26 lists certain sections that should be included in the evaluation reports. These reports may be limited in scope, as described above.
Non-Event Based Resource. Example IOU	**<u>Ex Post for Non-Event Based Resources</u>** Protocol 14 (same as Protocol 7) requires impact estimates be reported in a table format. Uncertainty adjustments are not needed in the table. Protocol 15 requires reporting for the monthly system peak day.

[23] The deadline is typically April 1.

programs: TOU RTP SLRP PLS	Protocol 16 requires regression based methods (read section 5.2, pg 84 for guidance). Any suppliers choosing not to use regression as described in Protocol 10 *must* file an evaluation plan (Protocols 1-3) well in advance of the QC demonstration deadline. **<u>Ex Ante for Non-Event Based Resources</u>** Protocol 17 requires ex ante estimates should be informed by ex post whenever possible. Protocol 21 requires impact estimates be reported in a table format. Uncertainty adjustments are not needed in the table. Protocol 22 requires the use of 1-in-2 weather year for the monthly system peak day. The 1-in-10 weather year, average weekday, or typical event day are not needed for QC calculation. Protocol 23 requires ex ante estimates be based on regression methodologies (read section 6.2, pg 98 for guidance). **<u>Portfolio Impacts, if Required</u>** Protocol 24 describes methodology for estimating the impacts of multiple DR programs within a portfolio. All DR resources whose participants also participate in other DR programs (potentially operated by other entities) must follow Protocol 24; such resources should also submit an evaluation plan (Protocols 1-3). **<u>Sampling if Required</u>** Protocol 25 requires certain procedures to ensure that sampling bias is minimized. Protocol 25 is not anticipated to be required for most DR resources using LIPs only to demonstrate QC; DR resources with a small number of participating customers should provide data from *all* participants, obviating the need for sampling methodologies. For resources with enough participants to adopt a sampling methodology, an evaluation plan (Protocols 1-3) is required well in advance of the QC demonstration deadline. **<u>Evaluation Reporting</u>** Protocol 26 lists certain sections that should be included in the evaluation reports. These reports may be limited in scope, as described above.

Table 4. Required LIPs

As noted above, in order to summarize the detailed LIP information to monthly QC values, QC is measured using the average expected (ex ante) load impact during the appropriate measurement hours shown in Table 3. CPUC staff takes the hourly estimates provided[24] according to the LIPs and averages the estimates over the relevant hours.

In order for DR programs to receive local capacity credit for RA, the load impact must be broken down by local areas. However, this breakdown is not required for all months – it is only required for August. Further, for compliance purposes the CPUC aggregates PG&E's "other" local areas: Fresno, Humboldt, North Coast/North Bay, Sierra, and Stockton. These areas do not need to be broken out individually. For August, average expected (ex ante) load impact must be provided by local area as follows, for each DR program:

SDG&E	SCE	PG&E
San Diego	Big Creek/Ventura	Greater Bay Area
System (no local area)	LA Basin	Other PG&E local areas
	System (no local area)	System (no local area)
Program Total	Program Total	Program Total

Table 5. Local Area Breakdown for DR Resources.

For each program, the sum of system and local capacities should equal the program total capacity. Table 5 is not intended to be a format, but simply a description of the data required. If a program operates in multiple IOU territories, expected load impacts for all relevant local areas should be included.

Avoided line losses should be included along with the LIP estimates for QC calculation purposes, but not directly included in the LIP estimates. CPUC staff will "gross-up" the DR QC for avoided line losses. A single loss rate for each service area is calculated according to Equation 12. Total Line Loss Factor

[24] If assumptions underlying the LIP estimates for a particular program are unreasonably optimistic, CPUC staff accordingly reduces the load impacts.

$$LossRate = 3\% + DistributionLossRate$$

Equation 12. Total Line Loss Factor

The service area specific distribution loss rate is calculated from the most recent available data submitted in each IOUs current or previous general rate case. Generally, in the rate cases the IOUs submit loss factors from each of several locations on the transmission and distribution grid. The ratio of the transmission loss factor to the secondary distribution loss factor yields the loss rate for sub-transmission and distribution, which is called the distribution loss rate.

$$DistributionLossRate = \frac{TransmissionLossFactor}{SecondaryDistributionLossFactor}$$

Equation 13. Distribution Loss Rate

Finally, the QC of DR is calculated by grossing up by the loss rate.

$$FinalQCofDR = \frac{\sum_{MeasurementHours} AverageExAnteLoad\,\mathrm{Im}\,pact}{\{NumberOfMeasurementHours\}} * \left(\frac{1}{1 - LossRate}\right)$$

Equation 14. Final QC of DR

11. Acronym List

Acronym	Definition
CAISO ID	California ISO Scheduling Resource ID
California ISO	California Independent System Operator
CEC	California Energy Resources Conservation and Development Commission
CPUC	California Public Utilities Commission
HE	Hour Ending
IOU	Investor Owned Utility
kW	Kilowatt
kWh	Kilowatt-hour
LGIP	Large Generator Interconnection Procedures
LIP	Load Impact Protocol
MW	Megawatt
MWh	Megawatt-hour
NQC	Net Qualifying Capacity
PMax	Maximum Power Plant Output
QC	Qualifying Capacity
RA	Resource Adequacy
SAS®	Statistical Analysis Software
SC	Scheduling Coordinator
SGIA	Small Generator Interconnection Agreement
SGIP	Small Generator Interconnection Procedures
SLIC	Scheduling and Logging for ISO of California

(END OF APPENDIX B)

INFORMATION REGARDING SERVICE

I have provided notification of filing to the electronic mail addresses on the attached service list.

Upon confirmation of this document's acceptance for filing, I will cause a Notice of Availability of the filed document to be served upon the service list to this proceeding by U.S. mail. The service list I will use to serve the Notice of Availability of the filed document is current as of today's date.

Dated May 25, 2010, at San Francisco, California.

/s/ JEANNIE CHANG
Jeannie Chang

N O T I C E

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* *

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