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Decision 11-10-003 October 6, 2011

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

DECISION FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM REGARDING DEMAND RESPONSE RESOURCES

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DECISION FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM REGARDING DEMAND RESPONSE RESOURCES

1. Summary

In this decision, we adopt the following changes to the current Resource Adequacy (RA) rules for demand response resources:

- A demand response resource may receive local RA credit only if it is capable of being dispatched by local area. This requirement goes into effect in 2013. This rule does not apply to dynamic pricing programs.
- Creation of a new Maximum Cumulative Capacity bucket for demand response resources for 2013.

In addition, we adopt as a policy statement that fossil-fueled emergency back-up generation resources should not be permitted to receive system or local RA credit as demand response resources. We will consider specific rules related to this policy in future RA proceedings.

2. Background

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

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

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

An *Assigned Commissioner's Ruling and Scoping Memo* (Scoping Memo), issued on November 3, 2010, identified two broad categories of issues for Phase 2 of this proceeding. The first category, local RA issues, pertains to the CAISO's 2012 local capacity requirements (LCR) study as well as this Commission's establishment of local procurement obligations for 2012 based on the LCR study. The second category pertains to various proposals to modify the RA program.

The Scoping Ruling was revised on February 3, 2011. Among other things, the revised Scoping Memo deferred to a future phase of this proceeding a CAISO proposal to review a plan for a non-generic capacity procurement requirement process to add resource operational characteristics such as regulation and ramping "load following" capabilities into the RA procurement requirements. This issue is still pending.

The Commission's Energy Division facilitated workshops on RA program refinement issues on January 18 and 25, 2011. Comments on the Phase 2 issues discussed in the workshops were filed on February 8, 2011 by Alliance for Retail Energy Markets (AReM); Calpine Corporation (Calpine); the CAISO; California

Large Energy Consumers Association (CLECA), Cogeneration Association of California (CAC); Division of Ratepayer Advocates (DRA); Dynegy Morro Bay, LLC, Dynegy Moss Landing, LLC, Dynegy Oakland, LLC and Dynegy South Bay, LLC (Dynegy); GenOnCalifornia North LLC and GenOn Delta LLC (GenOn); EnerNOC, Inc. (EnerNOC); Pacific Gas and Electric Company (PG&E); Southern California Edison Company (SCE); San Diego Gas & Electric Company (SDG&E); and The Utility Reform Network (TURN). The CAISO; DRA; Dynegy; Independent Energy Producers Association (IEP); PG&E; SCE; SDG&E; and TURN filed replies on February 22, 2011.

D.11-06-022 established local capacity procurement obligations for 2012 applicable to Commission-jurisdictional LSEs, based on an annual study of local capacity requirements performed by the CAISO for 2012. In addition, that decision adopted a number of RA program refinements, including the following demand response items:

1. The requirement that to qualify for RA requirements, a resource must be able to operate for a minimum of four hours per day for three consecutive days, now applies to all demand response resources in the RA program.
2. For 2012, demand response program totals allocated towards RA credit for the Base Interruptible Program, the Summer Discount Plan, and the Agricultural Pumping Interruptible Program, subject to the conditions of a Settlement in D.10-06-034.
3. For the 2012 RA program only, PG&E was granted an exemption from the RA program requirement that demand response programs must operate from 1:00 p.m. to 6:00 p.m.
4. The purpose of this decision is to address certain additional demand response issues related to RA, based on the record of this proceeding.

3. Demand Response Issues

3.1. Demand Response Resource Dispatch by Local Area

In yearly RA decisions, we adopt the LCRs for the investor-owned utilities' (IOUs') Local Capacity Areas (local areas).[1] RA rules require that all conventional RA resources (i.e., all RA resources except for demand response resources) be dispatchable by local area in order to count for local RA credit. Currently, demand response resources may qualify for both system and local[2] RA credit even though not all demand response programs are capable of being dispatched by local area.

The CAISO proposes that the Commission modify the RA counting rules such that a demand response resource may receive local RA credit only if it is capable of being dispatched by the CAISO in a defined RA local area. The CAISO argues that "(a)llowing demand response programs to count for local RA when they are not 'dispatchable' like other RA resources 'where needed' is inconsistent with the central tenet of the CPUC's RA program. All resources are 'point' resources … . There is no such thing as a 'system RA resource' that makes energy available to the grid wherever it happens to be located on the grid."[3]

The CAISO contends that when the IOUs trigger a system-wide demand response event to respond to a local need, demand response provided

[1] See CAISO's map for the IOUs' Local Capacity Areas (local areas): http://www.caiso.com/2b34/2b34c7716ccd0.pdf, at Slide 2.

[2] The local RA credits are given for the IOUs' demand response load impact within the local RA areas. The 2011 local RA credits for demand response programs are shown at http://www.cpuc.ca.gov/NR/rdonlyres/786A98AC-9F92-4D8D-A071-6A8065944CCE/0/2011IOUDRProgramTotalsFinal728.xls.

[3] CAISO Comments on Phase 2 Issues filed on February 8, 2011 at 7.

outside of the local area is not only unnecessary and economically inefficient, but also "could result in incremental congestion … if demand response occurs where is not needed or expected."[4] The CAISO asserts that costs associated with such congestion would likely exceed a utility's costs to get demand response resources to conform and operate like all other RA resources.[5] In addition, the CAISO argues that it is necessary to change the current rule to encourage the integration of retail demand response programs with the wholesale market.

Dynegy supports the CAISO proposal. Dynegy argues that shedding load in local areas other than the load needed to address a local reliability problem in a specific area is both inefficient and could create congestion where none had previously existed.[6]

PG&E opposes the CAISO proposal. PG&E contends that it is practically impossible for PG&E to modify all its demand response programs by 2012 so that the programs would all be dispatchable by local capacity area. If the local RA value of these programs is eliminated, PG&E claims that ratepayers will incur the unnecessary cost of procuring more local RA when demand response resources are already in place to serve that local need.[7] SCE similarly opposes the CAISO proposal, claiming it is not cost-effective and would be difficult to implement.

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[4] See CAISO's Comments on Phase 2 Issues at 8.

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

[6] Dynegy Reply Comments on Phase 2 Issues at 4.

[7] PG&E Reply Comments on Phase 2 Issues at 3.

SDG&E notes that the CAISO's definition of "dispatchability" is unclear. SDG&E opposes adopting the CAISO proposal until pending issues related to the 2012-2014 demand response proceedings[8] are addressed. SDG&E also notes that its programs operate through a process that is triggered when the utility calls the demand response customer, and opposes breaking this direct link between the retail electricity provider and the customer. SDG&E objects to the notion of CAISO-dispatchability being used as a qualifying criterion if it encompasses the intervention of the CAISO in the utility-customer interaction.[9]

3.1.1. Discussion

We adopt the CAISO proposal that a demand response resource may receive local RA credit only if it is capable of being dispatched by Local Capacity Area (LCA). However, this requirement does not apply to the IOUs' dynamic pricing DR programs. We will defer the applicability related issues to a future RA proceeding.

We agree in principle with the CAISO that the fundamental reason for a locational dispatchability requirement for all RA resources is to meet local capacity needs. This rule will make demand response resources provide reliability benefits similar to other RA resources. The alternative – forcing the CAISO to manage demand response resources that do not meet a locational dispatchability requirement -- could increase energy costs for consumers by requiring the CAISO both to purchase capacity which may not fit its needs or to purchase additional capacity to cover uncertainties about dispatch.

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[8] A.11-03-001 et al.

[9] SDG&E Reply Comments on Phase 2 Issues at 4.

A Commission decision on the IOUs' demand response portfolios for 2012 through 2014 is not anticipated until the end of 2011. The IOUs have a legitimate concern that they would need to know if any demand response programs would be exempt from the local dispatchability rule prior to the end of 2011 in order to procure alternate RA capacity for 2012. We also recognize that requiring all existing demand response programs to be locally dispatched may not be achievable by the start of 2012 as the IOUs may have to modify specific program designs and operational systems or procedures in order to comply with the new rule. Therefore, we will delay the effective date for this rule one year until the 2013 RA compliance year.

For 2013, the IOUs may request from Energy Division exemptions for specific demand response programs for that RA compliance year. A request for an exemption to the rule must demonstrate that the specific demand response program could not be modified in compliance with the rule for either of the following reasons:

1) <u>Timing</u>: If Commission proceedings addressing demand response program designs and funding issues have not concluded with sufficient time to modify the program in question prior to the 2013 RA compliance year.
2) <u>Policy</u>: If the Commission has found in a demand response proceeding that a particular demand response program should not be modified to comply with the rule for various reasons, e.g., cost-effectiveness or implementation-related issues.

We disagree with SDG&E's suggested delay of the rule change until the Commission's decision on the IOUs' 2012-2014 demand response budget applications. Instead, these applications can address the design and operational modifications that are necessary for the IOU demand response programs to comply with a local dispatchability requirement.[10] The demand response budget applications (and future dynamic pricing proceedings) are the appropriate places to determine the costs (if any) and timing necessary to modify demand response programs to conform to the local dispatchability requirement.

We concur with SDG&E's concerns about further defining what CAISO dispatchability means. To be clear, the IOU retail demand response programs should be dispatchable by the IOU at the CAISO's direction. The local dispatchability rule that we adopt does not insert the CAISO within utility-customer interactions in the IOUs' retail demand response programs. We concur with the CAISO, which acknowledged that its "tariff does not extend jurisdiction beyond wholesale products to retail demand response programs."[11]

In comments on the Proposed Decision, PG&E brought up a valid point about the differences between the LCAs and Sub Load Aggregation Points (subLAPs).[12] SubLAPs are more granular than LCAs. The CAISO requires that all Proxy Demand Resource (PDR) and Reliability Demand Response Product (RDRP) resources are dispachable by subLAP.

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[10] Some of the IOUs' existing demand response programs already have local dispatch capability. In its pending demand response budget application, SCE proposes to bid 1,360 MW (72% of its total demand response) into the market with full locational dispatch capability. (See A.11-03-003 at 2.)

We also recognize that modifying the IOUs' default dynamic pricing programs to be locally dispatchable would have to be addressed in separate rate design proceedings. In addition, there might be other issues related to the implementation of locational dispatch because of the revenue neutrality of default dynamic rates. However, as the IOUs implement default dynamic pricing for different customer classes, it would become a much bigger part of their demand response portfolio.

[11] See CAISO's Comments on Phase 2 Proposals filed on February 8, 2011 at 6.

[12] PG&E's comments on the Proposed Decision at 2.

Some subLAPs are within a single LCA, some overlap with two or more LCAs, some are partially or completely outside of LCAs. We clarify that PDR and RDRP resources that are dispatchable by subLAP may qualify for local RA, only if these resources or portions of these resources are located within the LCAs. For example:

1) If a PDR or RDRP resource is within a LCA, its load impact may be counted as local RA for that LCA.
2) If a PDR or RDRP resource is within two or more LCAs, the LSE should identify the load impacts for each LCA as the IOUs currently do in their April 1 Load Impact filings and may count it for the corresponding LCA.
3) If a PDR or RDRP is partially inside one or two LCAs, the LSE should identify the portion of the load impact from each LCA and may count it for the corresponding LCA.
4) If a PDR or RDRP resource is located outside of the LCA, the load impact should only count for system RA, not local RA.

Not all of the customers of IOUs' current retail DR programs are located within the LCAs. We currently require the IOUs to identify portions of load impacts within each LCA in their annual April 1 Load Impact filings. We determine the amounts counted for local and system RA based on these filings. Similarly, we require that all LSEs provide load impacts from PDR and RDRP resources that may be counted for system RA and identify the amount for each LCA that may be counted for local RA by April 1 of the RA compliance year.

We will defer the compliance details, such as mapping of subLAPs with respect to LCAs, to the 2013 RA proceeding. We will require the IOUs to coordinate with the CAISO to develop detailed mapping and make it available to the Energy Division, all non-IOU LSEs, and the Demand Response Providers (DRPs) in the 2013 RA proceeding.

In its comments on the Proposed Decision, PG&E raised concerns regarding its dynamic pricing being subject to the local dispatchability requirement. PG&E is concerned with the exemption criteria in the Proposed Decision that the rule would apply unless PG&E requests for an exception. PG&E also argues that its "dynamic rate programs are not designed to be callable on a local basis."[13]

In its reply comments, CLECA argues that the Commission has not determined that "all DR should be bid into the CAISO's markets."[14]

In its reply comments, the CAISO argues that dynamic pricing reduces the IOU load forecast,[15] therefore, does not require RA treatment. The CAISO raised a new issue related to the RA counting for dynamic pricing.

The IOUs' recently implemented default dynamic pricing for the large customer classes. Under the current rules, this program counts for RA purposes.[16] We assumed that the load forecast did not reflect the load impact. It is important to ensure that there will be no double counting of dynamic pricing between load forecast and RA credits when default dynamic

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[13] PG&E's comments at 4.

[14] CAISO's reply comment at 3.

[15] CAISO's reply comment at 5.

[16] Under the current RA rules, any event-based DR programs would be eligible for RA counting.

pricing is established in the long-term.[17] Therefore, we will address this issue in the 2013 RA proceeding. It is more logical to address the RA counting for dynamic pricing DR programs before we resolve the local dispachability requirement for these programs.

We recognize that there are potential implications of applying the local dispatchability requirement to dynamic pricing DR programs. It is not clear that all such implications have been fully considered in the record of this proceeding. Therefore, we will adopt this the local dispatchability requirement at this time (with a 2013 implementation timeframe) for all DR programs in this decision except for dynamic pricing programs. We defer the question of applicability of local dispatchability for dynamic pricing-related issues to a future RA proceeding.

Also in response to comments on the Proposed Decision, we clarify that the exemption criteria is intended to allow the Commission to address the program design and cost-effectiveness of the local dispachability requirement for the non-dynamic pricing DR programs that may not be able to comply with this requirement in 2013. It is the IOU's obligation to request for an exemption in the 2013 RA proceeding; and to provide quantitative and qualitative analysis in the appropriate proceedings. The IOUs must fully address the non-compliance related issues if they believe the local dispatchability requirement should not apply to certain non-dynamic pricing DR program(s) if any. We will re-evaluate the exemption criteria for 2014 and beyond in the next RA proceeding.

[17] If the load impact from dynamic pricing is reflected in the load forecast (as a demand-side resource), giving a RA credit (as a supply-side resource) to the same resource would be double counting.

3.2. Maximum Cumulative Capacity

Under the current RA rules, an LSE meets its RA requirement by submitting a portfolio of conventional RA capacity contracts and demand response programs, if any. Conventional RA resources, depending on the availability, each fall within one of four different resource categories which are commonly referred as the Maximum Cumulative Capacity Buckets (MCC buckets).

Unlike demand response resources, all conventional resources in each MCC bucket are dispatchable in the wholesale market and are subject to the CAISO's availability requirements, including performance and penalty rules that are outlined in its Standard Capacity Product. (In this decision, we require all demand resources to be dispatchable starting in the 2013 RA compliance year.) In addition, conventional resources are included in supply plans submitted to the CAISO. Demand response resources that qualify for RA credit are not accounted for in the MCC buckets, but instead are recognized as a credit that reduces an LSE's total RA requirement (also known as "taking off the top"). Demand response resources thus reduce the amount of conventional RA resources that an LSE would need to procure to meet its RA requirement.

The CAISO proposes that demand response programs should be required to fall within either existing or new MCC buckets as supply side resources. The CAISO states:

> "(w)hether the bucket is existing or new, the important factor is that demand response be treated equivalently to supply-side resources, not taken off the top of the LSE's RA requirement. This is important because all resource types should be treated comparably for RA capacity counting purposes. Counting demand resources on the supply side establishes a structure to enable the competitive solicitation, procurement and resource adequacy showing

> of demand response resources by Load Serving Entities. Like all other RA resources that fall within the MCC buckets, the creation of a MCC bucket for demand response will allow demand response resources to be listed as supply-side resources on the monthly and annual RA plans and supply plans that are submitted to the [CA]ISO."[18]

EnerNOC also proposes the creation of a new MCC bucket for demand response resources. EnerNOC proposes that this category would either require a minimum of 48 hours over the summer months and or four hours for three consecutive days for demand response.[19]

AReM supports EnerNOC's proposal to modify the MCC categories to accommodate demand response resources either by adding a new demand response-specific bucket or a modification to Bucket 1 to allow for demand response resources to qualify for that bucket.

SDG&E generally supports the idea of creating an additional MCC bucket to capture the contribution from demand response resources or other use limited resources. However, SDG&E is unable to support EnerNOC's request to add another bucket at this time because SDG&E claims EnerNOC's proposal lacks specific criteria that would define the new bucket. SCE does not object to the creation of a new MCC bucket to accommodate the availability hours of demand response.

DRA opposes the creation of a MCC bucket to include the CAISO's new demand resources product[20] in this proceeding and recommends this issue be

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[18] See CAISO's Comments on Phase 2 Proposals filed on February 8, 2011 at 9.

[19] EnerNOC Proposals on Phase 2 Issues at 6.

[20] DRA refers to the Proxy Demand Resource product, discussed elsewhere herein.

deferred to a later phase of the proceeding, once the new CAISO product has been implemented and other demand response products are developed.

PG&E contends that the settlement adopted by the Commission in D.10-06-034 eliminates the need to create a MCC bucket for demand response by limiting the amount of emergency demand response.[21] PG&E appears to believe that the limit on emergency demand response in the settlement is sufficient to accommodate the new CAISO product, so that there is no need to create a MCC bucket.

3.2.1. Discussion

We adopt the CAISO proposal to create a new MCC bucket for demand response resources for 2013. As with locational dispatchability, we will make this change to current RA policy so that demand response can be treated comparably with supply side resources. The new MCC bucket will help with integration of retail demand response programs with the wholesale market and should significantly increase use of the demand response resources.

We intend to use the new bucket for all demand response resources, not just emergency triggered demand response. Therefore, we disagree with PG&E that the settlement adopted in D.10-06-034 eliminates the need to create a MCC bucket for demand response.

Implementing a new MCC bucket for demand response necessitates an update of existing MCC buckets with more recent information on the system demand. The size of the current four MCC buckets (as shown in Table 1 below) were adopted in the 2005 RA decision,[22] which was based on a historical peak

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[21] PG&E Comments on Phase 2 Issues at 6.

[22] D.05-10-042.

load duration curve. These buckets are now out of date as additional peak load data is available from 2005 to 2010.

EnerNOC's proposed requirement of a minimum 48 hours over the summer months may be the correct number of hours for the new demand response MCC bucket, but further analysis and up-to-date information for all MCC buckets is needed for us to determine the correct size of each bucket, including the new demand response bucket.

Table 1

Summary of Resource Categories	
Category	Resources may be categorized into one of the four categories shown below, according to their planned availability as expressed in hours available to run or operate per month (hours/month):
1	"Greater than or equal to" the ULR [Use Limited Resource] monthly hours as shown in the Phase 1 Workshop Report, Table "Number Hours ISO Load Greater than 90% of the Monthly Peak," p.24-25, last line of table, titled "RA Obligation," http://www.cpuc.ca.gov/word_pdf/REPORT/37456.pdf These ULR hours for May through September are, respectively: 30, 40, 40, 60, and 40, which total 210 hour and have been referred to as "the 210 hours."
2	"Greater than or equal to" 160 hours per month.
3	"Greater than or equal to" 384 hours per month.
4	All Hours (planned availability is unrestricted)

We defer implementation details on the new MCC bucket for demand resources to the upcoming 2013 RA compliance year proceeding. In that proceeding, we anticipate seeking specific implementation proposals so as to obtain all necessary analytical data for the evaluation and modification of the existing MCC buckets.

3.3. Resource Adequacy Counting Method for the Proxy Demand Resource Product

In the 2011 RA decision (D.10-06-036), the Commission adopted the use of Load Impact Protocols to establish the Qualifying Capacity of demand response resources (both retail and wholesale). In that decision, the Commission did not see any evidence that wholesale demand response resources (referred as "supply-side" demand response) existed and would require different RA rules from retail demand response resources. On August 10, 2010, the CAISO implemented the proxy demand resource product (PDR), which is a wholesale demand response product. According to the CAISO, PDR is a load or an aggregation of loads of retail customers capable of reducing their electric demand in response to the CAISO's dispatch instructions. The load reductions are measurable and verifiable by the CAISO. In this section, we will address the RA rules for PDR.[23]

3.3.1. Load Impact Measurement

D.08-04-050 adopted protocols for estimating the impact of demand response activities on electric load. In D.10-06-036, the Commission reaffirmed that demand response resources should use these load impact protocols:

> 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 Qualifying Capacity (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 energy markets is subject to

23 See Phase 2 Scoping Ruling issued on November 3, 2010 at 5.

> uninstructed deviation penalties for real-time performance problems, and is subject to Standard Capacity Product (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 load impact protocols (LIPs) are used to establish the QC of DR resources to the maximum extent possible.

EnerNOC proposes using a registered capacity method to measure the Qualifying Capacity of PDR, instead of using the adopted load impact protocols. EnerNOC claims that the registered capacity method is comparable to other supply side resources that participate in the wholesale market. EnerNOC argues that the load impact protocols were developed for the purpose of estimating demand response impacts of retail programs and determining cost-effectiveness, not for the purpose of bidding a resource into the wholesale market.[24] EnerNOC also claims that other programs that are provided by aggregators are based on a portfolio of resources put together to provide a consistent load response when called. EnerNOC contends the registered

[24] EnerNOC Comments on Phase 2 Issues at 2.

capacity accurately represents the capacity that EnerNOC intends to provide to the grid when dispatched.[25]

AReM supports EnerNOC's proposal, arguing that using the current load impact protocols is complex, non-transparent and unduly time-consuming.[26]

DRA opposes EnerNOC's proposal because DRA does not believe EnerNOC has demonstrated a need to change the existing load impact protocols and adopt a different methodology.

The CAISO states that the Commission should determine how demand response resources count for RA value, either through the load impact protocols or another methodology, such as some form of a registration, certification or actual testing of their performance characteristics.[27] In reply comments, the CAISO states that registration, certification, and actual testing of operational capabilities provides a sufficient alternative to the load impact protocols. The CAISO requests the Commission adopt this approach as an alternative to the load impact protocols for determining the Qualifying Capacity of a demand response resource.

PG&E opposes using any other methodology than the load impact protocols to determine the RA value for all demand response resources including the PDR product.[28] In its reply comments, PG&E argues that a demand response

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[25] EnerNOC Comments on Phase 2 Issues at 3.

[26] AReM Comments on Phase 2 Issues at 12.

[27] CAISO Comments on Phase 2 Issues at 7.

[28] PG&E Comments on Phase 2 Issues at 7.

provider's determination of its registered capacity is a "black box" to the rest of the world[29] and thus is less transparent than the load impact protocols.

SDG&E is not convinced that changing the Qualifying Capacity methodology for demand response from the load impact protocols is necessary or beneficial. Unless the load impact protocols present serious, insurmountable barriers to third party demand response providers, SDG&E prefers the status quo to a system of untested self-declarations.[30]

SCE opposes EnerNOC's proposal to use a registered capacity value instead of the load impact protocols to determine the Qualifying Capacity of demand response resources. SCE contends the load impact protocols provide a more accurate, consistent method for determining demand response Qualifying Capacity values.[31]

3.3.1.1. Discussion

We will continue to use the load impact protocols for demand response resources, consistent with D.10-06-036. Parties have not shown that registered capacity value is a more accurate and transparent method for measuring the Qualifying Capacity of demand response resources.

We disagree with EnerNOC regarding the purpose of the IOUs' load impact protocols. The load impact protocols are not only an input in determining demand response program cost-effectiveness, but are also used for the calculation of the RA credits for all IOUs' demand response programs. In D.10-06-036, we recognized that the full list of load impact protocols is extensive

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[29] PG&E Comments on Phase 2 Issues at 3.

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

[31] SCE Comments on Phase 2 Issues at 2.

and that many of these load impact protocols are not applicable for RA counting purposes. For this reason, we adopted a much shorter list of load impact protocols in D.10-06-036 for the load measurement of demand response resources for RA counting purpose.[32]

The CAISO believes that registration, certification, and actual testing of operational capabilities provide a sufficient alternative to the load impact protocols. The CAISO is concerned with the complexity of the 27 elements of the current load impact protocols, which may increase barriers for demand response programs to participate in the RA program.[33] We understand the CAISO's concerns, and do not wish to impose such barriers. However, we are concerned that PDR is new to the RA program. It is not clear that EnerNoc's proposed method is a more accurate and transparent method for measuring the Qualifying Capacity of PDR that the load impact protocols adopted in D.08-04-050.

The CAISO is in the process in developing demand response availability, performance, and penalty rules applicable to all demand response recourses counted for RA, including PDR. Commission staff should participate in CAISO's initiative to help ensure that emerging rules require consistent methodologies for load impact measurement.

3.3.2. Local Area Credit for the Proxy Demand Resource Product

EnerNOC contends that since the PDR product will have locational-dispatch characteristics by sub-load aggregation points, this resource

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32 See D.10-06-036, Appendix B at 18-22.

33 CAISO Reply Comments on Phase 2 Issues at 6-7.

should receive credit for meeting local RA requirement through bilateral contracts.

3.3.2.1. Discussion

Under current RA rules, the LSEs receive local RA credits for the load impact of the demand response resources within the IOUs' local areas regardless of the program's ability to be locally dispatched. As discussed above, we will modify the current RA rules and require local dispatchability for all demand response resources (including PDR) as a condition to qualify for local RA credit. We agree with EnerNOC that a PDR product that provides RA capacity through bilateral contracts should be able to receive local RA credit if the PDR resource is located in a local area, just like any other demand response or conventional resource.

3.3.3. Use of Fossil-Fueled Emergency Back-Up Generation a Proxy Demand Resource for RA Credit

In a 2002 demand response rulemaking (Rulemaking 02-06-001), the Commission developed a vision statement with the California Energy Commission and the Consumer Power and Conservation Financing Authority entitled, "California Demand Response: A Vision for the Future (2002-2007)." The vision statement listed three main objectives for demand response, one of which was environmental protection,[34] and stated: "(t)he Agencies' definition of demand response does not include or encourage switching to use of fossil-fueled emergency backup generation, but high-efficiency, clean distributed generation may be used to supply on-site loads."(Emphasis in original.)[35]

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[34] The other two main objectives were: reliability and lower power costs.

[35] D.03-06-032, Attachment A at 2.

In 2003, the joint agencies first adopted an Energy Action Plan[36] that proposed specific actions to ensure that adequate, reliable, and reasonably priced electrical power and natural gas supplies are achieved and provided through policies, strategies, and actions that are cost-effective and environmentally sound.

The 2008 Updated Energy Action Plan[37] established a Loading Order, which in part ranks preferred energy resources for California. Demand response is one of the highest priority resources (with energy efficiency) in the Loading Order "followed by renewable resources, and only then in clean conventional electricity supply." [38] Back-up generation typically uses high emitting fossil fuels, therefore making it a resource that is below demand response in the Loading Order.

Energy Division proposes that any demand response program (whether operated by IOUs or non-IOUs) that uses fossil fueled back-up generation for demand reduction cannot count towards an LSE's RA obligations. Energy Division's proposed rule would prohibit both the explicit and implicit use of back-up generation as a demand response for RA counting purpose.

PG&E opposes Energy Division's proposal. PG&E claims utility demand response programs have always generally allowed customers to manage how they meet their demand response commitments behind the meter, including

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[36] http://docs.cpuc.ca.gov/published/REPORT/28715.htm

[37] http://www.cpuc.ca.gov/NR/rdonlyres/58ADCD6A-7FE6-4B32-8C70-7C85CB31EBE7/0/2008_EAP_UPDATE.PDF

[38] See 2008 Updated Energy Action Plan at 1.

(http://www.cpuc.ca.gov/NR/rdonlyres/58ADCD6A-7FE6-4B32-8C70-7C85CB31EBE7/0/2008_EAP_UPDATE.PDF) the use of back-up generation.[39] PG&E argues that the Commission decisions cited by Energy Division are not supportive of its recommendation, because those decisions speak to specific demand response programs using back-up generation to obtain Technical Incentive funds. PG&E contends that its demand response programs place no restrictions on a customer using its back-up generator to meet its demand response load drop requirement, and that these long-standing, fully approved demand response programs should not be penalized by eliminating their RA value.[40] Further PG&E advocates that the more appropriate forum for this issue be in the 2012-2014 demand response program application.[41]

EnerNOC requests that all the potential benefits of back-up generation participation be considered before deciding to exclude the use of them from RA credit. EnerNOC supports the use of back-up generation units for RA eligibility in the PDR as long as the back-up generation units comply with relevant air pollution control regulations.[42]

CLECA opposes Energy Division's proposal. CLECA argues that Energy Division misunderstands the Commission's policy with concerning back-up generation units. CLECA claims the Commission has never prohibited the use of back-up generation by customers participating in demand response programs. Instead, CLECA believes the decisions cited by the Energy Division rejected proposals for using funding for demand response technical incentives

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[39] PG&E Comments on Phase 2 Issues at 7.

[40] PG&E Comments on Phase 2 Issues at 8.

[41] PG&E Reply Comments on Phase 2 Issues at 4.

[42] EnerNOC Comments on Phase 2 Issues at 7.

for cleaner diesel back-up generation or for paying incentives for customers to use back-up generation in lieu of utility service for part or all of their load.[43]

CLECA further argues that RA counting has nothing to do with how a customer manages a load reduction when participating in a demand response program; instead, RA counting has to do with the megawatts of demand reduction achievable in response to an event or price signal as measured by the load impact protocols.[44]

SDG&E opposes any prohibition of using back-up generation to meet RA requirements. SDG&E argues that if back-up generation can fit into one of the Maximum Cumulative Capacity buckets and meets the eligible requirements of a supply side resource, then back-up generation should be able to count as a supply side resource.

DRA agrees with SDG&E that resources that use back-up generation should fit into one of the MCC buckets as a supply side resource and should receive RA credit. However, DRA does not believe that the capacity provided by back-up generation units should be considered as demand response resources that deserve the higher status in the Loading Order of the Energy Action Plan.

SCE does not support the Energy Division proposal. SCE states that further examination regarding the feasibility of excluding back-up generation units from demand response is necessary before this type of restriction is adopted.[45]

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[43] CLECA Comments on Phase 2 Issues at 2.

[44] CLECA Comments on Phase 2 Issues at 3.

[45] SCE Comments on Phase 2 Issues at 2.

3.3.3.1. Discussion

As a general policy, we do not want to allow fossil-fueled emergency back-up generation to receive system or local RA credit as demand response resources. In decisions on the IOUs' last three demand response program budget cycles (2005-2011), we have consistently stated that demand response programs that rely on using back-up generation were contradictory to our vision for demand response and the Loading Order.

In D.05-01-056 (approving the IOUs 2005 demand response programs and budgets), the Commission addressed two back-up generation-related demand response programs for which PG&E and SDG&E requested funding. The Commission rejected PG&E's 2005 plan for back-up generation program "because it promotes reliance on diesel generators as part of California's resource mix, in contrast to the Energy Action Plan's loading order preference… We continue to fail to see how a program that increases generation can be characterized as demand response(.)"[46] While the Commission approved SDG&E's program for 2005, it affirmed that such programs should not be funded through the demand response budget in future years.[47]

In D.06-11-049 (approving the IOUs' 2007 demand response programs), the Commission denied PG&E's request for demand response funding to retrofit existing customer-owned diesel back-up generators. This decision states:

> Our objective in funding demand response programs is to reduce system demand, not to substitute system

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[46] See D.05-01-056 at 48-49.

[47] See D.05-01-056 at 48.

> electricity with electricity generated by off-grid natural gas facilities. We previously found in D.05-01-056 that back-up generation is not a true demand response resource. As TURN states, counting a [Back-up Generation] program as demand response would 'turn the Commission's preferred resource loading order on its head.'[48] We, therefore, deny PG&E's request to initiate a [Back-up Generation] program.[49]

Most recently, in D.09-08-027 (approving funding for the IOUs' 2009-2011 demand response budget cycle), the Commission determined it was not appropriate to use demand response funds for back-up generation programs. The Commission reached its determination in rejecting a proposal by BluePoint Energy to recognize back-up generation as demand response.[50]

The cited decisions addressed the IOUs' requests for funding of back-up generation as demand response. The fundamental principle these decisions relied on is that the Loading Order should apply equally to non-IOU demand response programs using back-up generation that seek RA credits. Non-IOU operated demand response programs could emerge in the near term in light of the CAISO's recent implementation of the PDR product at the wholesale market. This rule will ensure that both retail and wholesale demand response resources are treated consistently with respect to the Loading Order and the RA program.

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48 TURN Opening Comments in A.05-06-006 et al. at 15.

49 See D.06-11-049 at 58.

50 See D.09-08-027 at 164.

We recognize that our previous decisions on back-up generation-related demand response program funding requests did not explicitly prohibit other demand response programs that might allow end-use customer to rely on back-up generation in response to an event. However, we reiterate our discussion on this point in D.05-01-056:

> "These two [back-up generation] programs are extremely troubling because they are not true demand reduction programs. Instead, they reduce demand on the utility system by shifting load to an onsite generation resource. Thus, although they do result in a short term reduction to the grid, there is no net reduction occurring as a result of them."[51]

Disallowing the use of back-up generation as part of a demand response program for RA purposes is consistent with the Loading Order of the Energy Action Plan. Back-up generation typically uses high emitting fossil fuels, which is far below demand response according to the Loading Order, which "established that the state, in meeting its energy needs, would invest first in energy efficiency and demand-side resources, followed by renewable resources, and only then in clean conventional electricity supply."[52] DRA correctly pointed out that the capacity provided by back-up generation units considered as demand response resources would get a higher status in the Loading Order.

In their comments on the Proposed Decision, PG&E, SCE, and CLECA argue that a customer in the program only uses a back-up generator to handle a part of the load covered by the program. These parties make a number of arguments that the rule change in the Proposed Decision would jeopardize

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[51] See D.05-01-056 at 47-48.

[52] See 2008 Updated Energy Action Plan at 1.

these DR resources, and conflict with other Commission policies regarding DR resources.

After reviewing parties' comments, we will adopt as a policy statement the Energy Division proposal that any demand response program, whether operated by an IOU or non-IOU, that uses back-up generation for demand reduction should not count towards RA obligations for any Commission-jurisdictional LSEs. This policy is consistent with the Commission's Vision Statement in D.03-06-032 (as well as in prior decisions in the last three-DR budget cycle proceedings). This policy statement applies to the explicit and implicit use of back-up generation for demand response to provide RA capacity.

We clarify that our definition of "explicit use" refers to any DR programs that provide financial incentives for customers to retrofit their on-site back-up generation and use it exclusively or mostly to provide demand reduction during a DR event. An example of the "implicit use" would be that the customers signed up for a DR program and own a back-up generation on site. They may or may not use it to provide demand reduction during a DR event.

We recognize that in our prior decisions, the Energy Division staff proposal, and parties' comments, a general term of "back-up generation" was used. There may be different types of back-up generations that exist today based on their uses and technologies. With the development of technology, there also might be some on-site energy storages that service as a back-up generation.

Consistent with our initial vision statement, we clarify that our policy statement only applies to fossil-fueled emergency back-up generation.[53]

At this time, we will not make any change to the RA rules to implement our policy statement regarding RA treatment of back up generation. We recognize parties' concerns regarding lack of data or analysis to the extent that customers use their BUGs for DR and enforcement related issues. Therefore, we will defer the RA rule change to a future RA proceeding when further studies or analysis become available.

We will require the IOUs work with Energy Division to identify data on how customers intend to use BUGs, and to identify the amount of DR provided by BUGs when enrolling new customers in the DR programs or renewing DR contracts. We will defer the details on the process evaluation to the IOUs' 2012-2014 DR applications.[54] We will also direct our Energy Division to make recommendations regarding ways to implement our policy statement consistent with overall Commission policies.

It appears that there was some confusion among parties in their comments that Energy Division's proposed rule would apply to all fossil-fueled BUGs used for emergency DR programs. That is not correct. We clarify that our policy statement applies only to fossil-fueled emergency BUGs as stated in our

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53 On March 3, 2010, the Environmental Protection Agency (EPA) published final National Emission Standards for Hazardous Air Pollutants (NESHAP) for existing internal combustion engines. NESHAP imposes much stricter standards for emission control for non-emergency engines than emergency engines. However, it has a 15-hour limit that the emergency engines can be used for emergency demand response programs versus no hour limits for the non-emergency engines.

54 A.11-03-001 et al.

Vision Statement in D.03-06-032 used for any DR programs. In general, the definition of emergency BUG should be consistent with the definition by the US Environmental Protection Agency (USEPA) or state or local air regulation agencies.

3.3.4. Incorporation of Standard Capacity Product Rules for Demand Response Resources

The CAISO is undertaking an initiative to create a Standard Capacity Product for demand response resources (SCP III). The CAISO's goal is to implement SCP III on January 1, 2013.

In its reply comments, PG&E argues that the CAISO is overreaching by stating that "retail demand response programs that cannot be configured under the SCP provisions will not meet the requirements to be RA capacity under the ISO tariff." PG&E urges the Commission and the CAISO to address SCP for demand response in the upcoming 2012-2014 demand response program applications.[55]

In its reply comments, PG&E argues that the CAISO is overreaching by stating that "retail demand response programs that cannot be configured under the SCP provisions will not meet the requirements to be RA capacity under the ISO tariff." PG&E urges the Commission and the CAISO to address SCP for demand response in the upcoming 2012-2014 demand response program applications.[56]

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[55] PG&E Reply Comments on Phase 2 Issues at 5.

[56] PG&E Reply Comments on Phase 2 Issues at 5.

SCE and SDG&E support the Commission completing the demand response applications before the CAISO creates requirements for demand response resources in the SCP III stakeholder process.

3.3.4.1. Discussion

We included this issue in the scope of this proceeding because CAISO originally envisioned that the SCP III would be designed, approved and effective for the 2012 RA compliance year. CAISO has since moved the implementation date for SCP III to 2013. Therefore, we will defer this issue to the 2013 RA proceeding.

4. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on August 29, 2011. Reply comments were filed on September 6, 2011.

5. Assignment of Proceeding

Mark J. Ferron is the assigned Commissioner and David M. Gamson is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. To the extent possible, RA credit rules related to demand response programs should be harmonized with rules related to conventional RA resources so demand response resources can be fully integrated with the CAISO market.

2. The proposed rule that retail demand response resources must be dispatchable locally in order to receive local RA credits is necessary and appropriate to further align the requirements for demand response performance with the RA rules for conventional resources.

3. Dynamic pricing programs cannot be dispatched locally at this time.

4. It is reasonable to create a new MCC bucket for demand response resources starting in 2013.

5. Parties have not shown that registered capacity value is a more accurate and transparent method than the current load impact protocols for measuring the Qualifying Capacity of demand response resources.

6. Allowing the use of fossil-fuel back-up generation as part of a demand response program for RA purposes is not consistent with the Loading Order of the Energy Action Plan.

Conclusions of Law

1. Retail demand response resources should be required to be dispatchable locally in order to receive local RA credits, with the exception of dynamic pricing programs.

2. A new MCC bucket should be created for demand response resources starting 2013.

3. The load impact protocols for demand response resources from D.10-06-036 should continue.

4. There is not sufficient information in the record to adopt specific RA rules regarding fossil-fuel back-up generation.

5. It is reasonable to adopt as a policy statement that fossil-fuel emergency back-up generation resources should not be allowed as part of a demand response program for RA purposes, subject to rules adopted in future RA proceedings.

O R D E R

IT IS ORDERED that:

1. The Commission's Resource Adequacy program, as adopted in Decision 11-06-022, is modified as follows:

   a. Retail demand response resources are required to be dispatchable locally in order to receive local Resource Adequacy credits starting in the 2013 Resource Adequacy year, except for dynamic pricing programs.

   b. A new Maximum Cumulative Capacity bucket is created for demand response resources, subject to the parameters of the bucket to be determined by the Commission for the 2013 Resource Adequacy year.

2. In consultation with Energy Division and coordination with the California Independent System Operator, Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall develop detailed mapping of the sub Load Aggregation Points with respect to the Local Capacity Areas in their service territories.

3. In consultation with Energy Division, Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall identify data on how customers intend to use back-up generation and identify the amount of demand response provided by back-up generation when enrolling new customers in, or renewing, demand response programs.

4. Rulemaking 09-10-032 is closed.

This order is effective today.

Dated October 6, 2011, at Los Angeles, California.

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

I abstain.

/s/ MICHEL PETER FLORIO
Commissioner