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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 11-10-023 (Filed October 20, 2011)

DECISION ADOPTING LOCAL PROCUREMENT AND FLEXIBLE CAPACITY OBLIGATIONS FOR 2015, AND FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM

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DECISION ADOPTING LOCAL PROCUREMENT AND FLEXIBLE CAPACITY OBLIGATIONS FOR 2015, AND FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM

1. Summary

This decision adopts local capacity procurement and flexible capacity obligations for 2015 applicable to Commission-jurisdictional electric load serving entities. These procurement obligations are based on an annual study of local capacity and flexible capacity requirements performed by the California Independent System Operator (CAISO or ISO) for 2015 which seeks to ensure that each part of the California grid, including those parts with transmission constraints, has access to sufficient generating capacity to meet the local need. The total local "capacity requirements" recommended by the CAISO, and adopted herein, for all local areas combined decreased slightly from the prior year; the decrease is from 27,307 Megawatts (MW) in 2014 to 26,345 MW in 2015. We agree with the ISO's determination that the "existing capacity" needed to meet the ISO capacity requirement decreased from 26,053 MW in 2014 to 25,227 MW in 2015.

In this decision, we also adopt an interim "flexible capacity" framework for 2015 through 2017 as an additional component of Resource Adequacy (RA) requirements, as anticipated by D.13-06-024. "Flexible capacity need" is defined as the quantity of resources needed by the CAISO to manage grid reliability during the greatest three-hour continuous ramp in each month. Resources will be considered as "flexible capacity" if they can sustain or increase output, or reduce ramping needs, during the hours of the ramping period of "flexible need."

This decision also adopts Qualifying Capacity and Effective Flexible Capacity determinations for Energy Storage and supply-side Demand Response resources. Several minor refinements are made to the RA program for 2015.

2. Background

Pub Util. Code § 380 (as amended by Stats. 2008, ch. 558, Sec. 13, effective January 1, 2009)[1] requires that "the commission, in consultation with the Independent System Operator (ISO or CAISO),[2] shall establish resource adequacy [RA] 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 RA program and its 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 three phases. Phase 1 considered local capacity procurement obligations for 2013 applicable to

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[1] All subsequent statutory references are to the Public Utilities Code unless stated otherwise.

[2] The California Independent System Operator is abbreviated herein as either CAISO or ISO.

Commission-jurisdictional electric LSEs and several proposed RA program refinements, resulting in Decision (D.) 12-06-025. Phase 2 considered local capacity procurement obligations for 2014 applicable to Commission-jurisdictional electric LSEs, and several proposed RA program refinements, resulting in D.13-06-024. D.13-06-024 also adopted an interim "flexible capacity" framework as an additional component of RA requirements. "Flexible capacity need" was defined as the quantity of resources needed by the ISO to manage grid reliability during the greatest three-hour continuous ramp in each month. Pursuant to D.13-06-024, resources will be considered as "flexible capacity" if they can sustain or increase output, or reduce ramping needs, during the hours of the ramping period of "flexible need."

An *Assigned Commissioner's Ruling and Scoping Memo* (Scoping Memo), issued on August 2, 2013, identified the issues to be considered in Phase 3 of this proceeding as well as the procedure and schedule for their consideration. Today's decision in Phase 3 determines local capacity procurement obligations for 2015 applicable to Commission-jurisdictional electric LSEs and sets further RA program refinements. For the first time, this decision also adopts flexible capacity requirements for Commission-jurisdictional electric LSEs.

The Commission's Energy Division facilitated workshops on RA program refinement issues[3] on January 27 and April 9, 2014. A summary of the April workshop was transcribed.

Comments on the Phase 3 issues were filed by Alliance for Retail Energy Markets (AReM); Calpine Corporation (Calpine); CAISO; California Energy

3 Excluding the 2015 local capacity requirements and flexible capacity requirements.

Storage Alliance (CESA); California Large Energy Consumers Association (CLECA); California Wind Energy Association (CalWEA); Center for Energy Efficiency and Renewable Technologies; Clean Coalition; Cogeneration Association of California, California Cogeneration Council, Energy Producers and Users Coalition (the CHP Parties); Concentrating Solar Power Alliance; EnerNOC, Inc. (EnerNOC); Environmental Defense Fund; Green Power Institute (GPI); Imergy Power Systems, Inc., Primus Power, ZBB Energy Corporation, EnerVault Corporation, and UniEnergy Technologies, LLC (together, the Joint LDES Parties); Independent Energy Producers Association; Large-Scale Solar Association; Marin Clean Energy (MCE); MegaWatt Storage Farms, Inc. (MegaWatt); Natural Resources Defense Council (NRDC); NRG Energy, Inc. (NRG); Office of Ratepayer Advocates (ORA); Pacific Gas and Electric Company (PG&E); Shell Energy North America (US), L.P. (Shell); Sierra Club; Solar Energy Industries Association; Southern California Edison Company (SCE); San Diego Gas & Electric Company (SDG&E); The Utility Reform Network (TURN); and Vote Solar.

3. Local RA for 2015

This decision first adopts the amount of local RA needed to meet capacity needs in 2015.

3.1. 2015 Local Capacity Requirements Study

D.06-06-064 determined that a study of Local Capacity Requirements (LCR) performed by the CAISO would form the basis for this Commission's local RA program. The CAISO conducts its LCR study annually, and this Commission resets local procurement obligations each year based on the CAISO's LCR determinations. Following a stakeholder process, the CAISO posted its "2015 Local Capacity Technical Analysis, Final Report and Study Results" (2015 LCR

Study) on its website, served notice of the report's availability, and filed it with the Commission on May 1, 2014. No comments were filed on the 2015 LCR Study.

The CAISO states that the assumptions, processes, and criteria used for the 2015 LCR Study were discussed and recommended in a stakeholder meeting, and that, on balance, they mirror those used in the 2007 through 2014 LCR studies. The CAISO identified and studied capacity needs for the same ten local areas as in previous studies: Humboldt, North Coast/North Bay, Sierra, Greater Bay, Greater Fresno, Big Creek/Ventura, Los Angeles (LA) Basin, Stockton, Kern, and San Diego-Imperial Valley.

The CAISO reports that LCR needs have decreased by about 1,000 MW or about 3.5% from 2014 to 2015. The LCR needs have decreased in the following areas: Humboldt, North Coast/North Bay and Bay Area due to downward trend for load; LA Basin due to new transmission projects; and Kern due to area redefinition required after a transmission project. LCR needs have increased in Big Creek/Ventura and San Diego due to load growth; in Sierra due to load growth and delay in development of transmission projects; and in Fresno due to effectiveness factors and requirements of the second worst contingency. The slight increase of LCR needs in San Diego is due to availability of new transmission projects, without which the increase driven by load growth would have been much bigger. LCR needs in Stockton have increased slightly due to increase in deficiency; however, the overall need for existing generation capacity has decreased due to the downward trend for load.

2015 Local Capacity Requirements									
	Qualifying Capacity			2015 LCR Need Based on Category B			2015 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	36	171	207	116	0	**116**	166	0	**166**
North Coast / North Bay	130	771	901	550	0	**550**	550	0	**550**
Sierra	1299	771	2070	1392	29*	**1421**	1803	397*	**2200**
Stockton	197	392	589	357	0	**357**	396	311*	**707**
Greater Bay	1262	6243	7505	3492	0	**3492**	4231	136*	**4367**
Greater Fresno	316	2532	2848	2393	0	**2393**	2393	46*	**2439**
Kern	408	87	495	108	26*	**134**	411	26*	**437**
LA Basin	2208	8985	11193	8620	0	**8620**	9097	0	**9097**
Big Creek/ Ventura	1160	4203	5363	2095	0	**2095**	2270	0	**2270**
San Diego-Imperial Valley	219	4328	4547	3910	0	**3910**	3910	202*	**4112**
Total	**7235**	**28483**	**35718**	**23033**	**55**	**23088**	**25227**	**1118**	**26345**

2014 Local Capacity Requirements									
	Qualifying Capacity			2014 LCR Need Based on Category B			2014 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	70	173	243	145	0	**145**	195	0	**195**
North Coast / North Bay	150	771	921	623	0	**623**	623	0	**623**
Sierra	1288	762	2050	1414	0	**1414**	1803	285*	**2088**
Stockton	212	392	604	354	25*	**379**	446	255*	**701**
Greater Bay	1336	6280	7616	3747	0	**3747**	4423	215*	**4638**
Greater Fresno	318	2510`	2828	1857	0	**1857**	1857	0	**1857**
Kern	613	64	677	421	14*	**435**	421	41*	**462**
LA Basin	2242	9547	11789	10063	0	**10063**	10430	0	**10430**
Big Creek/ Ventura	1112	4206	5318	2156	0	2156	2250	0	**2250**
San Diego-Imperial Valley	200	4506	4706	3605	167*	**3772**	3605	458*	**4063**
Total	**7541**	**29211**	**36752**	**24385**	**206**	**24591**	**26053**	**1254**	**27307**
* CAISO note: No local area is "overall deficient." Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency, the numbers are carried forward into the total area needs. Resource deficient sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.									
** CAISO note: Since "deficiency" cannot be mitigated by any available resource, the "Existing Capacity Needed" will be split among LSEs on a load share ratio during the assignment of local area resource responsibility.									

We determine that the CAISO's final 2015 LCR Study should be approved as the basis for establishing local procurement obligations for 2015 applicable to Commission-jurisdictional LSEs.

3.2. Continuation of the Local RA Program

The RA program was first adopted in D.06-06-064. That decision adopted a framework for local RA and established local procurement obligations for 2007 only. D.07-06-029, D.08-06-031, D.09-06-028, D.10-06-036, D.11-06-022, D.12-06-025 and D.13-06-024 established local procurement obligations for 2008 through 2014, respectively. The RA program has been refined each year since

2007. The local RA program and associated regulatory requirements adopted in those decisions continue in effect for 2015 and thereafter until changed, subject to the 2015 LCRs and procurement obligations adopted by this decision.

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

In previous decisions, we delegated ministerial aspects of RA program administration to the Commission's Energy Division. Once again, Energy Division should implement the local RA program for 2015 in accordance with the adopted policies.

4. Flexible Capacity Requirements

In D.13-06-024, in consultation with the CAISO and with other stakeholders, we recognized that there was a need to specify more about which types of resources must be procured for RA purposes. We noted that reliability needs are changing over time because a) recent State Water Resources Control Board rule changes necessitate contracting for resources to replace potential lost capacity in the local areas, which are presently dependent on once through cooling (OTC) plants for local reliability, and b) the increased flexibility requirements due to the state's 33% Renewable Portfolio Standard might change the state's net load profile over the next several years. Going forward, we expect that our continued standard of high reliability of the grid will require a more complex and flexible fleet of resources as the amount of generation that is non-dispatchable increases and begins to challenge CAISO grid management. The changing supply due to OTC restrictions and the increased penetration of non-dispatchable generation will necessitate changes to the way that the residual flexible and dispatchable generation is bid and operated by the CAISO.

We accomplished this through defining "flexibility," so that LSEs can procure resources to meet RA needs in ways which more precisely meet changing reliability needs. To this end, we adopted a flexible capacity framework to start in 2015. D.13-06-024 recognized a need for flexible capacity in the RA fleet and defined flexible capacity need: "Flexible capacity need" is defined as the quantity of economically dispatched resources needed by the CAISO to manage grid reliability during the greatest three-hour continuous ramp in each month. Resources will be considered as "flexible capacity" if they can sustain or increase output, or reduce ramping needs, during the hours of "flexible need." (D.13-06-024 at 2). D.13-06-024 adopted the following formula to calculate system flexibility requirement:

> Flexibility NeedMTHy= Max [(3RRHRx) MTHy]+ Max(MSSC, 3.5%*E(PLMTHy)) + ε
>
> Where,
>
> Max [(3RRHRx) MTHy] = Largest three hour continuous ramp starting in hour x for month y
>
> E(PL) = Expected peak load
>
> MTHy= Month y
>
> MSSC = Most Severe Single Contingency
>
> ε = annually adjustable error term to account for uncertainties such as load following.

The adopted framework was shown in detail in Appendix A of D.13-06-024.

Regarding implementation of the flexible capacity framework, D.13-06-024 stated:

> For the next year, we will gather information, analyze such information, hold workshops to consider refinements to the adopted flexible capacity framework, and build a record for such refinement in our expected June 2014 decision in this docket or its successor.

D.13-06-024 also specified a number of tasks to be completed for this year's RA Decision, including: a) development of counting rules, eligibility criteria, and must-offer obligation for use-limited resources, preferred resources, combined cycle gas turbines, and energy storage resources for Commission consideration; b) determination of a cap or a method to calculate the annually adjustable error term in the methodology used to calculate flexible capacity need; c) development of compliance rules and penalties; and d) the assumptions underlying the calculation of flexible capacity need.

Following a stakeholder process, the CAISO filed its draft "Preliminary 2014 Flexible Capacity Needs Assessment" in this proceeding on April 4, 2014 and its final assessment on May 1, 2014 with an addendum on May 5, 2014.

Based on its analysis, the CAISO's identified the maximum flexible capacity needs for each month of 2015 (*see* table below). The flexible capacity needs range from 7,861 MW (August 2015) to 11,212 MW (December of 2015). The flexible capacity needs increased from those identified for 2014, but did not increase by the amount forecasted from last years' study, primarily because fewer renewable resources are expected to be brought on line before or during 2015. As illustrated in the table below, most of the flexible capacity needs are allocated to CPUC-jurisdictional load serving entities (e.g., ~97% of the required need in February 2015).

NOTE: All numbers are in MegaWatts	CAISO System Flexible Requirement	CPUC Flexible Requirement	Category 1 (minimum)	Category 2 (100% less Cat. 1 & 3)	Category 3 (maximum)
January	9,459	8,972	6,639	1,884	449
February	10,465	10,099*	7,473	2,121	505
March	9,543	9,025	6,679	1,895	451
April	8,468	8,005*	5,924	1,681	400
May	7,520	7,134*	4,851	1,926	357
June	9,078	8,707	5,921	2,351	435
July	8,083	7,694	5,232	2,077	385
August	7,861	7,464*	5,076	2,015	373
September	8,523	8,126	5,526	2,194	406
October	10,381	9,818*	7,265	2,062	491
November	10,848	10,460	7,740	2,197	523
December	11,212	11,035	8,166	2,317	552

*These values are calculated by adding the numbers in the addendum to the Flexible Capacity Assessment filed May 5, 2014 (Revised Table 8). The marked numbers differ from the Flexible Capacity Need table (Figure 7) by 1 megawatt in the Flexible Capacity Assessment filed May 1, 2014. For allocation among LSEs we will use numbers in the above table.

In addition, the CAISO proposes to divide the flexible capacity needs into three categories. These categories are defined based on the CAISO's assessment of the different types of flexible capacity needed to address the CAISO's needs. Specifically, in the flexible resource adequacy criteria and must offer obligation (FRAC-MOO) stakeholder initiative, the CAISO proposed the following flexible capacity categories:

> Category 1 (Base Flexibility): Operational needs determined by the magnitude of the largest 3-hour secondary ramp.
>
> Category 2 (Peak Flexibility): Operational needs determined by the difference between 95% of the maximum 3-hour net-load ramp and the largest 3-hour secondary net-load ramp.

> Category 3 (Super-Peak Flexibility): Operational needs determined by 5% of the maximum 3-hour net-load ramp of the month.

While the CAISO has identified the flexible capacity needs by category by month, the CAISO has proposed to establish the requirements on a seasonal basis, consistent with the Energy Division proposal discussed below. Accordingly, the CAISO proposes minimum percentages for base flexibility resources of 68% of the flexible requirements in summer (May – September), and 74% for the winter (all other months). The allocation of these percentages to CPUC-jurisdictional entities by category is shown in the table above.

PG&E and TURN submitted comments on the CAISO 2014 Flexible Capacity Needs Assessment on May 8, 2014. PG&E recommends that the Commission acknowledge that further work is expected in the 2015 Flexible Capacity Needs Assessment (for the 2016 RA compliance year) to improve upon the methodology used to calculate flexible capacity requirements. TURN recommends that as a starting point for all future Flexible Capacity Needs Assessment studies, the CAISO should develop a Flexible Capacity Needs Assessment computation manual (much as it has for computing Local Capacity Requirements) and also annotate and provide non-confidential data and computations. TURN also suggests that flexible requirements for 2015 be computed based on summer (May-September) and non-summer (October-April) seasons, consistent with the current Resource Adequacy (RA) seasons and the CAISO's proposal for computing the allocation of its three "categories" of flexible capacity. We encourage CAISO to consider these recommendations for the 2015 Flexible Capacity Needs Assessment prepared for 2016 flexible needs.

4.1. The Staff Flexible Capacity Proposal

On February 10, 2014, Energy Division issued a "Staff Proposal on the Implementation of the Flexible Capacity Procurement Framework" (Staff Flexible Capacity Proposal). Comments were filed on February 24, 2014 and reply comments were filed on March 6, 2014. A revised Staff Flexible Capacity Proposal was provided to parties ahead of a workshop held on April 9, 2014, and was placed into the record of the proceeding via the transcribed summary of that workshop. Further comments were filed by parties on April 18, 2014 and reply comments were filed on April 25, 2014. The revised Staff Flexible Capacity Proposal included:

1. Flexible capacity requirements allocation methodology among LSEs
2. Effective Flexible Capacity (EFC) counting conventions for resources
3. RA showings for flexibility
4. Rules for the sale and purchase of flexible capacity
5. Compliance including penalties
6. Flexible categories for resources

The CAISO initiated its own stakeholder initiative, the FRAC-MOO initiative, to develop the tariff changes necessary for the CAISO to accommodate the resource adequacy flexible capacity requirements adopted by the Commission and other Local Regulatory Authorities (LRAs). This initiative includes establishing availability standards, must offer obligations and default provisions for LRAs that choose not to develop flexible capacity procurement obligations for the LSEs under their jurisdiction. As part of the FRAC-MOO initiative, the CAISO issued a series of straw proposals, the last being the Draft Final version dated March 7, 2014. ORA notes that the FRAC-MOO proposal still has to go through the Federal Energy Regulatory Commission (FERC) approval process. PG&E recommends that the Commission take the status of the CAISO's FRAC-MOO implementation into account as its makes its determination to implement mandatory flexible RA requirements for the 2015 RA compliance year. We agree with PG&E. We take note of PG&E and ORA's concern but we do not believe we need to act on the premise at this time that the FRAC-MOO proposal will be delayed at FERC.

The revised Staff Flexible Capacity Proposal and the FRAC-MOO proposal converge on many issues; specifically, both the CAISO and Energy Division propose to divide the flexible capacity needs into three categories based on the duration of must offer obligations, energy limitations, and number of starts. While the categories have the same characteristics, the procurement requirements recommended by staff and the CAISO are different. The revised Staff Flexible Capacity Proposal recommends establishing a fixed requirement that 80% of flexible capacity meet the base flexibility criteria or Category 1 for all months of the year. The CAISO proposes a varying monthly Category 1 minimum based upon the largest secondary net load ramp for the specific month. The monthly values in the CAISO's Preliminary 2014 Flexible Capacity Needs Assessment range between 51% and 90%.

4.2. Parties' Position on Flexible Capacity Proposal

Alignment of Staff and Energy Division Staff Proposals: Various parties express concerns over the differences in the Staff Flexible Capacity Proposal and the CAISO FRAC-MOO proposal. PG&E maintains that it is critical that the two frameworks be consistent, since inconsistent requirements and obligations would only add confusion and cost to the flexible RA framework. ORA recommends that the CAISO and the Commission coordinate to establish consistent flexible capacity policies and requirements. AReM notes that lack of uniformity in the counting of EFC and how much of each category must be procured would create real world problems for buyers and sellers of capacity.

In this decision, we work to minimize differences between the flexible capacity requirements (FCRs) we adopt and the CAISO's FRAC-MOO proposal. We recognize that the CAISO's FRAC-MOO proposal is neither final nor adopted by FERC, and may change. We take into consideration the CAISO's comments in this proceeding (as well as comments by other parties) and narrow the differences between our adopted FCRs and the proposed FRAC-MOO. It is our expectation that the CAISO will align its evolving FRAC-MOO proposal as closely as possible to the framework adopted in this decision.

Flexible Capacity Requirements: While most parties support the imposition of FCRs on LSEs in 2015, MCE, AReM and Shell Energy do not. MCE strongly recommends that the Commission delay implementing the interim FCR obligation. AReM states that it is not realistic to expect market participants to enter into transactions to meet these new FCRs when so many details have yet to be worked out.

Shell Energy urges the Commission to defer implementation of a mandatory FCR obligation until the 2016 compliance year (or later) because the need for an FCR obligation in 2015 has not been established. Shell Energy notes that at the April 9, 2014 workshop in this proceeding, the CAISO confirmed that more than 30,000 MW of flexible capacity resources are available in 2014, compared to a "need" for flexible capacity in 2015 (and 2016) that ranges from slightly more than 7,500 MW in May to slightly less than 11,500 MW in December. Shell Energy further cites CAISO reports that, in fact, the need for flexible capacity has declined in some months because less renewable capacity has been brought on-line than the CAISO previously anticipated. Shell Energy contends the evidence does not support imposition of an FCR obligation on all LSEs in the 2015 compliance year.

It is factually correct that there is more flexible capacity available for 2015 than there is flexible capacity need for 2015. However, flexibility is not just a construct of flexible operational characteristics, it is equally a construct of availability; flexible resources are economically bid into the CAISO market and are not self-scheduled. Having excess flexible capacity in the fleet does not guarantee that this flexibility is available to the CAISO to meet ramping needs unless it is economically bid into the market. There is no way to know if self-scheduled flexible resources will bid into the market when needed. Imposing flexible obligations ensures that LSEs contract for flexible resources and bid them into the CAISO market.

Shell Energy notes that flexibility needs declined in the 2015 CAISO needs assessment from its 2014 assessment and argues that this is further evidence that mandatory flexible obligations are not required. We disagree. A decline in forecasted flexibility needs is not indicative of an absence of flexibility needs. D.13-06-024 adopted a methodology to calculate flexible needs. Flexibility needs for each month are the sum of the largest three-hour net-load continuous ramp and contingencies.

We examined the CAISO 2014 Flexible Capacity Needs Assessment to verify if there was a need for flexibility in 2015. We find the CAISO's calculations consistent with the approved methodology in D.13-06-024. Thus, we find that the CAISO's "Flexible Capacity Needs Assessment" filed with the Commission on May 1, 2014, shows a need for flexible capacity procurement; this need is due to ramping requirements arising from an influx of variable energy resources in the generation fleet. This need varies from 7,520 MW in May 2014 to 11,212 MW in December 2015.

Shell Energy also argues that the Energy Division was expected to collect data from the RA filings to assess the availability of flexible resources, before a 2015 FCR would be imposed. In the revised Staff Flexible Capacity Proposal, staff analyzed the 2014 annual RA showings before proposing flexible categories. We are satisfied that the analysis in the revised Staff Flexible Capacity Proposal appropriately reflects data gathered from 2014 annual RA showings.

AReM states that it is not realistic for the Commission or the CAISO to expect market participants to enter into transactions to meet these new FCRs when so many details have yet to be worked out. We disagree with AReM. Through this decision, we reconcile most of the differences between the CAISO and Energy Division proposals. The implementation of the flexible capacity framework is an evolving process and will undergo refinement and revision as parties and Commission understand and assess additional information (just as the framework for local capacity requirements has evolved over time).

At this stage, we have adequate details to adopt FCR obligations on load serving entities. With input from parties, we adopt a needs assessment, counting methodologies for various flexible resources, compliance rules for flexible RA showing, and flexible categories. Therefore, we have sufficient basis to impose FCR obligations on LSEs for 2015. We also reiterate the interim nature (through 2017) of the flexibility framework adopted in D.13-06-024:

> The Resource Adequacy (RA) program is modified by adoption of a flexible capacity framework as shown in Appendix A for all Load Serving Entities, as defined by Public Utilities Code Section 380(j). The flexible capacity framework will be mandatory starting with RA compliance year 2015.

> The adopted framework shall be in effect through RA compliance year 2017.[4]

We adopt the CAISO's proposed 2015 flexibility requirements. We also clarify that, while the specific adopted framework is interim, we do not anticipate ending a flexible capacity obligation after 2017. Instead, we expect that the interim framework will evolve based on analysis of data gleaned from the first years of the obligation.

Some parties make recommendations pertaining to the CAISO's 2014 FCR study. Sierra Club and NRDC urge the CAISO to include Additional Achievable Energy Efficiency assumptions in its Flexible Capacity Needs Assessment. While PG&E supports adoption of FCRs for the 2015 RA compliance year, PG&E also recommends that the CAISO: 1) make the study work papers available for review; 2) refine the study methodology to better reflect the effect of distributed generation on load shape; 3) refine the study methodology to reduce potential year-to-year volatility in results caused by reliance on only one year of historical load and wind and solar generation data; and 4) consider the treatment of controllable generation from renewable sources of power. We encourage the CAISO to consider recommendations made by Sierra Club, NRDC and PG&E before finalizing its 2015 flexibility needs assessment for 2016.

Allocation of Flexible Capacity to Load Serving Entities: Some parties support the staff proposal to use load-ratio share to allocate flexible capacity in 2015, but most parties favor an allocation based on causation in the future.

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[4] D.13-06-024, Ordering Paragraph 5.

PG&E supports allocating the flexibility requirement created by variable energy resources (VERs) to VERs. NRG argues that, at this time, the Commission should not consider allocating any portion of the flexibility requirement to VERs.

For the 2015 RA year, we will use load- ratio share to allocate flexibility among LSEs, as this is a practical interim solution while alternatives are considered. In the future, we intend to explore other methods of allocation based on causation through the RA proceeding, potentially in conjunction with staff's analysis of reliability needs.

Flexible Categories: ORA recommends that the Commission not adopt proposed categories for flexible capacity resources with use limitations for the 2015 RA year. TURN and MCE recommend delaying flexible capacity categorization at least from 2015 to 2016. PG&E urges the Commission and CAISO to align their approaches so that entities are not placed in the position of having to ensure compliance with two similar but inconsistent sets of requirements intended to serve the same purpose. According to MCE, the differences between CAISO and CPUC resource limits and requirements could result in LSES procuring flexible capacity resources that meet all applicable CAISO requirements yet be obliged to procure additional Category 1 flexible capacity solely as a compliance obligation.

SDG&E contends that divergence between the two programs can lead to the inefficient, ineffective, and/or uneconomic procurement of resources by LSEs and/or trigger otherwise unnecessary incremental or "backstop" procurement by the CAISO. SCE recommends that the Commission and the CAISO both adopt a seasonal average approach that, if properly constructed, would strike a reasonable balance between accuracy and administrative burden.

After the April 9, 2014 workshop, the CAISO re-assessed the flexible capacity categories previously proposed by the CAISO and Energy Division and proposed new seasonal requirements in its comments submitted on April 18, 2014. The CAISO now proposes to divide the flexible capacity needs contribution into two seasons that mirror the existing summer (May through September) and non-summer (January through April and October through December) seasons used for RA. In reply comments, SCE supports the use of these seasonal requirements and believes that they provide an acceptable level of both system reliability and administrative simplicity.

We adopt the CAISO revised proposal for seasonal flexible categories. We find that the use of seasonal categories strikes a balance between reliability, administrative ease, and accurate levels of procurement. Because this method resolves most concerns of parties, it is appropriate to adopt seasonable categories for 2015.

Unbundling of System and Flexible Capacity: D.13-06-024 adopted rules regarding the counting and sale and purchase of flexible capacity. Specifically, the decision specified that a megawatt of capacity could only be sold once as either generic or flexible. D.13-06-024 states in Appendix A:

> For procurement purposes, the flexible capacity of a resource must remain "bundled" with the generic capacity for a specific megawatt; therefore, flexible capability of that megawatt of capacity cannot be sold to another LSE as a separate product.

SDG&E proposes removing language that specified that a megawatt could be sold once. Because a "megawatt of capacity counts only once," the resource owner whose generic capacity had been sold could not later sell the flexible attributes associated with that generic capacity in a separate transaction or to another load-serving entity. Instead, SDG&E proposes that the same megawatt could count as a flexible megawatt in one LSE's portfolio and as an inflexible megawatt in another resource's portfolio. SDG&E explains that if the resource portfolio of an LSE reflects a flexible-capacity deficiency, the most cost-effective solution that could be available to the LSE is to procure the flexible-capacity attributes, without the underlying generic capacity, from an LSE with a surplus of flexible capacity. All else being equal, the price for the surplus flexibility attributes held by the seller LSE should reflect only the additional marginal costs associated with additional burdens of offering flexible attributes compared to generic capacity.

TURN believes SDG&E's proposal has merit and would likely reduce customer costs. Shell Energy supports SDG&E's proposal to permit the unbundling of the flexible and inflexible attributes of RA capacity. The CAISO supports SDG&E's proposal because allowing a resource to sell the flexible and generic attributes separately allows both the LSEs and the resources to make better procurement decisions and could lead to more efficient bilateral market outcomes. ORA recommends that SDG&E's unbundling proposal for flexible capacity be adopted by the Commission. GPI argues that there is no compelling need for qualifying capacity (QC) and flexible capacity to be bundled, and supports SDG&E's proposal.

SCE supports bundling flexible capacity with generic capacity for procurement transactions. In a fully unbundled world, each recognized RA capacity attribute could be sold independent of any other attribute. This scenario unavoidably leads to specific pricing of each attribute, both in LSE bilateral and CAISO backstop procurement. However, SCE notes that neither the CAISO nor the CPUC have a process in place for assessing the relative value of RA attributes, nor have they developed a framework within which to detect and mitigate abuse of market power. Although SCE believes the adopted method in D.13-06-024 is not optimal, SCE find this method reasonably confines the problem of separate attribute pricing.

AReM contends the SDG&E proposal is not workable or necessary. First, AReM claims the proposal would require some potentially complex management to prevent double counting of the capacity, since the must offer obligations of the flexible capacity are different from the must offer obligations of the generic capacity. Second, AReM notes that market-based transactions should work to enable LSEs who are long on generic or flexible capacity to make that available to LSEs that are short. EnerNOC recommends not bundling EFC and QC for demand response.

We agree with SDG&E that unbundling may provide additional opportunities for flexible attributes to be made available to the market and may foster procurement efficiencies. However, we are concerned that immediate adoption may lead to unforeseen consequences. For example, we see difficulties in implementation of tracking flexible and generic attributes within the same megawatt instead of counting the megawatt as flexible or inflexible. We will consider unbundling for the 2016 compliance year.

Effective Flexible Capacity of Combined Heat and Power (CHP) Resources: The Staff Flexible Capacity Proposal includes a method to count flexibility within a resource. The proposal provides a CHP resource owner with the latitude to designate an EFC value annually for each month of a counting year to reflect its unique operating requirements related to industrial host obligations or contract limitations, if the EFC does not exceed the net qualifying capacity (NQC) of the unit.

The CHP Parties support the EFC counting rules in the Staff Flexible Capacity Proposal and suggest that there must be a differentiation between a resource's EFC, and the amount of flexible capacity it is actually contracted to provide.

SDG&E contends the Staff's proposed convention is arbitrary and unrelated to the resource's actual operational capability to provide flexibility. SDG&E contends that a self-elected and potentially unachievable EFC rating could affect grid reliability, particularly if the CAISO believes it has more flexibility than is actually available. SDG&E recommends a more structured calculation to determine the EFC for CHP resources that mirrors the counting convention for dispatchable thermal resources. SDG&E recommends that the EFC range be limited to a value falling between the maximum of regulatory must-take generation portion and the NQC of the resource. The CAISO states similar concerns and recommends counting the EFC of a CHP resource as the minimum of the NQC, or Pmax minus Pmin.

In its reply comments, PG&E recommends that there should be no special counting rules to determine the EFC for CHP resources. PG&E recommends that the same formulas used to determine the EFC value for other resources should be used to determine the EFC value for CHP resources. The CHP parties' argue that SDG&E's proposal does not provide a rational basis for measuring the flexibility of a CHP facility, and should be rejected.

While we recognize that a CHP resource has unique operating requirements related to industrial host obligations, we also see merit in imposing a stricter cap on the EFC. The NQC for CHP facilities is set as the average of the exports to the grid for the prior three years. The maximum of regulatory must-take generation is the maximum amount of electricity the CHP facility may export to the grid. Therefore, NQC and the maximum regulatory must-take generation for CHP facilities are measures of export to the grid. Any EFC which is based on a narrow range between NQC and Pmin or NQC and the maximum regulatory must-take generation is very limited and not a correct measure of flexibility within the resource.

We find the CAISO approach more balanced. The EFC of a CHP resource will be capped at the minimum of NQC, or Pmax less Pmin. We will also allow the CHP resource owner to adjust this EFC downward based on the resource owner's assessment of the resource's obligations and capability. A CHP resource has the latitude to designate a committed EFC value annually for each month of a counting year as long as this value does not exceed the lesser of NQC, or Pmax minus Pmin.

4.3. Implementation

The implementation details for the 2015 flexible capacity RA framework are included in Appendix A. The Energy Division and CAISO will work together to analyze flexible procurement and dispatch data to inform future flexible procurement policy.

5. Qualifying Capacity and Effective Flexible Capacity for Energy Storage and Supply-Side Demand Response Resources

In D.13-06-024, the Commission identified several tasks to be undertaken for the June 2014 RA decision. These included "develop[ing] counting rules, eligibility criteria, and must-offer obligation for […] preferred resources […] and energy storage resources." Accordingly, the Scoping Memo, issued on August 2, 2013, included the following issue: "Determine the Qualifying Capacity for energy storage resources and wholesale demand response resources."

Since that time, the Commission adopted a 1,325 MW storage procurement target for 2020 (D.13-10-040), as well as conceptual bifurcation of demand response resources into load modifying and supply-side resources (D.14-03-026). These developments further highlight the need for methodologies to assign Local, System, and Flexible RA credit to storage and supply-side demand response resources.

In this proceeding, we define these methodologies with the understanding that both they and the underlying RA products may be further refined in future years. There are three proposed methodologies in the record for determining the qualifying capacity (QC) and/or effective flexible capacity (EFC) of storage and demand response resources.

5.1. The Staff Qualifying Capacity and Effective Flexible Capacity Proposal

Energy Division presented its Staff Qualifying Capacity and Effective Flexible Capacity Proposal (Staff QC/EFC Proposal), which revised an earlier Staff Proposal discussed at earlier workshops, at a workshop held April 9, 2014; parties filed comments and replies on April 18 and 25, 2014.

The Staff QC/EFC Proposal covers eligibility requirements for storage and supply-side demand response (DR), testing and verification, aggregation, a calculation methodology for QC, a calculation methodology for EFC, and recommendations for future refinements.

The Staff QC/EFC Proposal bases QC values on a resource's ability to generate power (or curtail load) over a continuous four-hour period, and bases EFC values on a resource's ability to ramp upwards or sustain output over three hours. The load impact protocols (LIPs) are used to determine supply-side DR RA values, in much the same manner as is done for existing utility DR (Retail

DR). DR or storage resource aggregation is permitted within a single sub-load aggregation point (Sub-LAP).

The proposal permits dispatchable "negative" operation (storage charging or load increase) to count towards EFC but not QC, resulting in EFC being greater than QC for resources with this capability. However, bundling of Flexible and System RA is maintained, and the positive-generation portion of a resource's EFC is limited to its NQC. Bi-directional[5] storage and demand response resources receive an EFC based on their ability to charge (or increase load) over 1.5 hours and discharge (or reduce load) over 1.5 hours. Such resources may have a discontinuity when shifting from negative to positive generation, and may take up to 45 minutes to do so.

5.2. The CAISO Proposal

The CAISO filed its EFC proposals for storage and demand response on April 18, 2014. The CAISO proposes to determine the EFC of supply-side demand response via a test conducted "on a random basis and [using] the previous ten days load data for a proxy demand resource to measure the load reduction and pay the resource's bid price for the testing period."

The CAISO storage EFC proposal mirrors the CAISO's FRAC-MOO approved by its Board of Directors in March 2014. The FRAC-MOO bases a storage resource's EFC on the MW range over which it can ramp upwards (or sustain) at a constant rate over three hours. The EFC is unbundled from the resource's QC and is also not limited by the CAISO's deliverability assessment. For bi-directional resources, the resource must register as a non-generating

[5] Bi-directional resources are capable of *both* dispatchable charging or load increase (negative generation) *and* discharge or load curtailment (positive generation).

resource. The CAISO also proposes that regulation energy management resources be permitted to qualify as Flexible RA resources.

5.3. Comparison of the Energy Division and CAISO Proposals

The Staff QC/EFC Proposal and CAISO proposals have much in common. However, there are several differences. Staff proposal elements that differ from the CAISO's include:

1. Regulation energy management resources are not eligible for RA credit.
2. The Staff QC/EFC Proposal includes QC methodologies for demand response and storage resources.
3. The Staff QC/EFC Proposal would allow demand response providers to select a three-month window for testing of Flexible RA resources (or to choose a precise test date and time in advance for System/Local RA), while the CAISO proposes to select the date randomly for Flexible RA resources.
4. Bi-directional resources need not be registered as non-generator resources to qualify for RA.
5. Up to 45 minutes' transition time between negative and positive modes is permitted, and does not count towards the three-hour operational period required for Flexible RA resources. Discontinuity in dispatchable output is also permitted during this time (e.g., due to minimum pump loads).[6]
6. The positive generation considered in determining EFC is limited to that calculated for System RA eligibility and is subject to NQC derating. However, because the Staff QC/EFC Proposal would result in a lower EFC relative to

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[6] Transition time and discontinuities are not permitted under the non-generator resources tariff and therefore not allowed under the CAISO proposal.

the CAISO's proposal, the CAISO would accept the lower CPUC number.

Bi-directional flexible resources must be capable of negative and positive generation for 1.5 hours each; the CAISO specifies that the total duration be three hours. Also, to prevent abuse of the rules, eligible charging or load increase energy is limited to double the discharging or curtailment energy.

5.4. The MegaWatt Storage Farms Proposal

On April 18, 2014, MegaWatt filed a proposal which recommends a single EFC methodology for all resources. For those resources that can reach full capacity instantly, MegaWatt proposes an EFC that is equivalent to the MW charge level that can be sustained over three hours, plus the MW discharge level that can be sustained over three hours:

EFC = ((MWh discharged over 3 hours) + (MWh charged over 3 hours))/3

5.5. Other Party Positions

This section summarizes other parties' positions regarding the proposals above.

Many parties request that the RA requirements adopted by the CAISO and by the Commission be as consistent as possible in order to avoid backstop, over-procurement, confusion, and other market inefficiencies. This position is taken by ORA, TURN, the CAISO, PG&E, SCE, SDG&E, EnerNOC, CESA, and AReM.

Comments on adoption of an EFC for storage were mixed. PG&E, Sierra Club, and NRDC recommend adoption of the Staff QC/EFC Proposal on this point. Finding the CAISO proposal simpler, TURN and CESA support that proposal on an interim basis. While they do not support the CAISO proposal, the Joint LDES Parties are also concerned by the complexity of the Staff QC/EFC

Proposal on this point. SCE recommends deferring adoption of a methodology to allow time for the Commission and the CAISO to align policies; this is opposed by CESA.

Many comments were also received related to bi-directional or negative-only resources. For example, Sierra Club and NRDC advocate that a 45-minute transition time for bi-directional Flexible RA resources should be allowed; the CAISO, SCE, MegaWatt, and the Joint LDES Parties disagree. Additionally, the CAISO and NRG state that a non-generating resource tariff is necessary, while the Sierra Club and NRDC find it too restrictive and recommend against its adoption. Sierra Club and NRDC also argue that negative-only demand response resources should not qualify for RA until potential energy waste has been considered. Duration for bi-directional resources was also addressed, with MegaWatt and the Joint LDES Parties opposed to combining negative and positive output durations to reach three hours. CESA and the CAISO propose that short duration regulation energy management storage be eligible, while PG&E is opposed.

Parties also submitted numerous comments on using the LIPs for supply-side DR QC and EFC. The CAISO proposes a purely test-based EFC for DR, because the LIPs are not designed for Flexible RA needs. EnerNOC opposes such a test-based EFC, but both parties advocate postponing adoption of a LIP-based EFC for DR until the LIP methodology has been revised. Meanwhile, SCE suggests a contract-based QC and EFC for DR, while PG&E recommends the use of the LIPs until a well-understood replacement is developed.

Looking forward, several parties agree that the LIPs should be revised to increase transparency and/or reflect the different impact considerations for flexible, bi-directional, and generic Sub-LAP level RA resources. This position is taken by the CAISO, EnerNOC, and PG&E. If LIPs are adopted for supply-side demand response, SCE and EnerNOC request that ex-ante values be used, not ex-post values.

Comments were also received relating to aggregation and demand response testing. The CAISO and PG&E support aggregating resources within the same Sub-LAP or custom LAP in 2015. EnerNOC prefers DLAP aggregation. It also requests a month-long testing window for flexible demand response resources. ORA supports staff's proposal for a three-month window and contends it should also apply to inflexible DR resources. CAISO proposes having Flexible RA test dates randomly selected, with no guaranteed testing window at all.

Finally, several parties had additional comments on resource duration. SCE and GPI support allowing two-hour resources to be RA-eligible. This is opposed by MegaWatt and the Joint LDES Parties.

5.6. Discussion

We agree with parties that it is valuable to have consistent requirements across the Commission and the CAISO. In cases where differences are unavoidable, Energy Division should continue to work with the CAISO to further refine policies at both organizations and achieve as much agreement as possible for the 2016 compliance year. Additionally, we recognize the need to balance inclusive, fair treatment of all resources that contribute to meeting ramping needs with the need for caution and thorough vetting prior to adoption of proposals that may impact reliability.

For demand response, we recognize that such resources, like all other resources, must comply with the testing requirements in the applicable CAISO tariff. Therefore, we adopt the staff proposal that testing for Flexible RA resources may occur during a three-month window specified by the demand response provider (DRP) as a default only, in the event that there is no applicable CAISO tariff. Such testing should be conducted by the DRP and submitted to the Commission by the LSE showing that resource in its RA compliance filing. However, if the CAISO sets a more stringent requirement (such as testing randomly selected to occur at any time within the resource's availability period), we will require that the LSE submit the data from that test instead. In either case, the load impact assessment and ex-ante analysis shall be conducted according to the load impact protocols. While we acknowledge that the inability to set a test window may be burdensome for demand response providers, for the 2015 compliance year we nevertheless defer to the CAISO in this area of operational reliability in light of the limited experience to date in flexible supply-side demand response. We encourage Energy Division, the CAISO, and other parties to work together to refine future requirements.

Additionally, while we agree with parties that a Sub-LAP (or custom LAP) aggregation limitation may be restrictive, we also appreciate the operational difficulties (such as congestion management) associated with DLAP and LCA-level aggregation. Therefore, consistent with the CAISO and staff proposals, and with existing retail demand response requirements, we maintain a Sub-LAP aggregation limit at this time, with custom LAPs permitted as well. If parties are able to resolve the operational challenges associated with larger scale aggregation in the future, we will reconsider this limit at that time.

For bi-directional resources, we share the CAISO's concern that a 45-minute transition time may have unforeseen grid reliability impacts, and we do not adopt the staff proposal to allow a 45 minute transition time for resources switching from negative to positive generation. However, because there is a clear potential for resources with a non-zero transition time to contribute in a reliable and quantifiable manner towards meeting ramping needs, we encourage Energy Division, the CAISO and other parties to further explore this concept so that it can be reconsidered for the 2016 RA compliance year.

Resource duration also appears to require further discussion. Several parties suggest revising the Flexible RA eligibility criteria to permit shorter duration resources. Others not only do not wish to see the current three hour operational requirement reduced, but also do not wish to allow negative and positive generation to be aggregated to meet that requirement. Meanwhile, the CAISO has proposed allowing regulation energy management resources, which operate on a 15-minute timeframe, to count as Flexible RA. The diversity of perspectives indicates that it may be valuable to revisit the definition of flexibility in the future. However, we find that there is insufficient evidence of reliability impacts to change the current three hour durational requirement for Flexible RA at this juncture.

The CAISO's proposal that all bi-directional resources must register as non-generator resources is another significant difference between the proposals. We share some parties' concern that this tariff may be unduly restrictive, and we are concerned that it does not allow for bi-directional demand response resources. Therefore, we do not adopt a non-generator resource requirement at this time. We do, however, direct Energy Division to work with parties in the coming year to consider whether the non-generator resource tariff is appropriate for all types of storage resources, to pursue any modifications necessary to create an inclusive yet operationally feasible tariff, and to develop an appropriate tariff for bi-directional supply-side demand response.

Additionally, we acknowledge many parties' support for unbundling of Flexible and System RA resources. However, as discussed elsewhere in this decision, we do not adopt unbundling at this time. Because the CAISO proposal unbundles the positive-generation portion of storage EFC from the determination of QC used in calculating System RA value, it is inconsistent with the currently-adopted bundling principle.

While we agree with parties such as TURN that the CAISO proposal is simpler, we nevertheless adopt the staff proposal to use the same $Pmax_{RA}$ for Flexible and System RA, and to limit the positive-generation portion of EFC to the NQC value determined in the CAISO deliverability assessment. This limitation increases complexity, but this complexity appears to be manageable. Further, to adopt unbundling for storage resources only would discriminate against other resource types.

We also acknowledge parties' concerns with continued use of the LIPs to assess QC for Retail DR, and their further application to QC and EFC for supply-side DR. We agree that the use of LIPs for QC and EFC should be revisited and either refined or replaced in the future. However, the LIPs are already being used for retail demand response, and alternatives have been insufficiently vetted for supply-side DR. We adopt the existing LIPs as the basis for determining the QC and EFC of supply-side DR in the 2015 RA compliance year on an interim basis. Energy Division should work closely with parties to explore alternatives for next year. Consistent with existing practice for retail demand response, analyses for supply-side response will be subject to adjustment by Energy Division.

To further maintain consistency with Retail DR, we adopt CLECA's proposal to require supply-side DR dispatch or testing once per calendar year.

5.7. Implementation and Next Steps

We adopt the Staff QC/EFC Proposal dated April 9, 2014 as modified herein. The final rules adopted for energy storage and supply-side demand response resources in the 2015 RA compliance year are found in Appendix B.

In light of the trade-offs and potential refinements discussed above, we emphasize that the methodologies adopted here are interim only. We anticipate extensive revisions in the 2016 compliance year as we further explore various issues raised in this proceeding and others that arise. Nevertheless, we believe that the QC and EFC calculation methodologies adopted here represent a valuable first step in acknowledging and quantifying the contributions of storage and supply-side DR resources towards resource adequacy and grid reliability.

6. Refinements to the RA Program

Each year, the Commission considers refinements to the RA program to improve functioning and address concerns that have arisen over time. For the 2015 RA compliance year, Energy Division issued six RA refinement proposals -- three addressed resources subject to the Cost Allocation Mechanism (CAM) and Combined Heat and Power (CHP) procurement issues and the remaining addressed local RA requirements and timing of CAM allocations -- on January 16, 2014.[7] A workshop was held on January 27, 2014 and parties filed comments on February 18 and replies on March 3, 2014.

On April 4, 2014, Energy Division issued revised RA proposals addressing the CAM and CHP procurement issues (Staff RA Refinement Proposal). A

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[7] http://www.cpuc.ca.gov/NR/rdonlyres/39C8D92B-CFF3-45BF-8CB2-0C6866E5769F/0/R1110023RAImplementationStaffProposals.pdf

workshop was held on April 9, 2014 to discuss changes that were made to the proposals. Parties filed comments on April 18, 2014 and reply comments on April 25, 2014.

6.1. CAM and CHP Resources Procured Outside the Procuring IOUs Service Areas and the Path-26 Constraint

D.06-07-029 adopted the Cost Allocation Mechanism (CAM). CAM allows the investor-owned utilities (IOUs) to allocate the capacity costs and benefits of certain new generation resources, to all benefiting customers within their service areas.[8] System reliability need identified in the LTPP proceedings is specific to the service area of each IOU. Each IOU is tasked with protecting reliable operation within their service area, although they do not serve all retail customers in their service area.

In D.07-06-029, the Commission adopted a Path-26 counting constraint process which is administered annually by the CAISO. Path-26 is a transmission line connecting SCE and PG&E between the Midway and Vincent substations. Because there are resources on either side of Path-26 that provide benefits to the CAISO relative to where load is, Path-26 is limited by its path rating; that is, the ability to transfer capacity across that path to serve load is rationed to LSEs.

The CAISO allocates the baseline transfer capability on Path-26 to LSEs based on the higher of (1) LSEs zonal load-ratio share and (2) the sum of the LSEs

[8] The types of resources eligible for CAM treatment are not the subject of this proposal. However, CAM resources are typically resources that get authorized through the LTPP process for system or local reliability (Marsh Landing, Walnut Creek, El Segundo, etc.).

"Grandfathered RA Commitments."[9] The next part of the process is the determination of the benefits of netting. This involves the voluntary submission of existing contracts[10] in opposing IOU service territories in order to functionally "increase" the transfer capacity of Path-26. The netting benefits are allocated to all LSEs on a load-ratio share basis as additional Path-26 transfer capability MWs.

CAM RA benefits have historically been aggregated by IOU service territory and sent to benefiting LSEs as either a North Path-26 CAM allocation or a South Path-26 allocation (depending on where the resource is located). The North and South CAM allocations function as credits used in calculating each LSEs annual and monthly system RA requirements in the system template. The annual and monthly requirements are calculated using the zonal load forecasts, the 15% Planning Reserve Margin, Path-26 allocations, North and South Path CAM credits, and North and South Path Reliability Must Run credits.

Since CAM resources are specific to the need determined in each IOUs service area, the North and South Path CAM allocations are consistent with the zone that the IOU (and other benefiting LSEs) serves load in.

Similar to the CAM process, D.10-12-035 (the qualifying facility (QF)/CHP settlement) established a cost treatment to be used to share the benefits and costs associated with meeting the CHP and greenhouse gas goals. This adopted cost treatment is almost identical to what was adopted in the LTPP decision for CAM

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9 Grandfathered RA Commitments are those RA commercial arrangements, (contracts of ownership rights) effective as of March 22, 2007 that use Path-26 to reach the LSEs loads, and will be continuing to deliver into the next compliance year.

10 Contracts entered into after March 22, 2007 that use Path-26 to reach the LSEs loads.

resources. Under the QF/CHP settlement framework, the costs and the RA benefits are also allocated to all benefiting customers. However, the treatment adopted by the QF/CHP settlement does not require that the CHP facility be located in the IOU's service territory.

In the last year, the IOUs' CHP requests for offers (RFOs) have resulted in procurement outside the IOUs' service areas; however, the RA benefits to the service area are limited by Path-26 constraints. Allocating CHP RA credit to LSEs in one service area for resources procured in another service area can be problematic for the following reasons: 1) it does not consider the Path-26 system constraint; 2) local costs are not equitably allocated, in that customers in one service area (that of the IOU conducting the RFP) are paying for reliability benefits in another area (the service area in which the CHP is located); and 3) it creates another level of complexity in procurement planning that is not transparent to LSEs that serve DA and CCA load.

The Staff RA Refinement Proposal would have limited the RA capacity benefits of the CAM and CHP to only resources that are procured in the same service area as the purchasing IOU. The utility procuring the CHP or other resource outside of its service area would not have been allocated the RA capacity credit of that resource to meet its system RA obligations.

All commenting parties opposed this proposal.

SCE proposes that, to mitigate the Path-26 issue, the Commission net the MWs associated with CHP procurement between the north and south IOUs on a system and local basis. SCE alternatively proposes a "take it off the top" method. This method would require the Commission and CAISO to reduce the total amount of Path-26 eligible for allocation by the non-netted CAM resources. This way the CAM resources could count for RA without violating Path-26 constraints.

AReM recommends that the Commission allocate the CAM/CHP RA benefits as required by statute and allow the LSE receiving the RA credit to use its Path-26 allocation, if it so chooses, to 'move' the RA credit to another utility jurisdiction for purposes of its RA compliance showing. Additionally, AReM states that it does not support SCE's proposal for taking any unnetted RA value of these CAM resources 'off the top' of the Path-26 allocation because it would disadvantage LSEs serving load in both the north and the south by limiting their flexibility to manage their RA portfolio.

PG&E also argues that CAM resources should take the Path-26 limitations into account and the Path-26 constraint should not be ignored, and supports for SCEs proposed netting alternative.

NRG and TURN believe that another staff proposal would address the Path-26 concerns identified in this proposal. NRG notes that if CHP and CAM resources are shown on RA plans, as proposed in another part of the Staff RA Refinement Proposal, this should allow the Path-26 counting constraint to be considered.

ORA argues that the staff proposal identifies valid concerns; however, ORA recommends examination of alternatives to disqualifying CHP and CAM RA allocations, such as linking the RA allowances to availability of access to Path-26.

The Staff RA Refinement Proposal was revised on April 4, 2014. In the revised proposal, Energy Division proposed that CHP resources procured outside of the IOUs north or south zone be required to be included in the Path-26 netting process. The IOU responsible for the CHP procurement outside of the

IOUs service area zone would submit the contract information to the CAISO as an existing contract in the Path-26 netting process adopted in D.07-06-029.[11] The additional available Path-26 capacity created by netting of these CHP contracts would be allocated to LSEs based on the LSEs netting participation-ratio share and no longer based on LSEs' load-ratio.

CAISO, NRG, TURN and SCE support the revised Staff RA Refinement Proposal on this point. SCE states that the revised proposal maximizes RA benefit from these resources as much as possible while minimizing the impact to the Path-26 allocation process. PG&E also supports the revised proposal, but recommends that the decision make clear that this change is applicable to all resources submitted to the Path-26 netting process, not only CAM and CHP resources.

SDG&E argues that some current contracts may not be able to take advantage of the proposed netting. In these instances, SDG&E recommends the CHP resources be netted against the grandfathered contracts flows accounted for in the earlier steps of the Path-26 allocation process to maximize the remaining Path-26 flow available for allocation in later steps.

CAC and CCC argue that the revised staff proposal should be clarified to specifically say that the increased transfer capability associated with the netting benefits be used exclusively to ensure delivery of the CHP resources. Additionally, CAC and CCC propose that excess quantities of CHP resources be exempt from the Path-26 counting constraint. CAC and CCC claim that under the pro forma QF Settlement contracts, there is an obligation on the part of the

[11] D.07-06-029 at 13.

IOUs to take delivery of power produced under the contracts. The proposed imposition of new counting constraints on those deliveries should not interfere with those deliveries. The IOUs should not be unfairly constrained in their performance under these contracts. CAC and CCC propose that such excess quantities be exempt from the imposition of the Path-26 counting constraint.

AReM claims that the modifications proposed by CHP parties, PG&E and SDG&E may reduce the Path-26 allocation to non-IOU LSEs. In order to ensure non-discriminatory allocation of Path-26 AReM contends the grandfathered contract language should not be modified.

6.1.1. Discussion

We agree with the concerns raised by parties on the initial Staff RA Refinement Proposal. If implemented, this proposal would raise costs for ratepayers and also disadvantage other CHP resources that were not subject to the proposed rule change. However, we also agree that a valid issue has been identified and needs to be addressed. We agree with NRG and TURN that if the revised Staff RA Refinement Proposal Scheduled Outage Replacement Rule for CAM and CHP resources' proposal is adopted then it would resolve the Path-26 issue.

We will adopt the revised Staff RA Refinement Proposal. There is value gained from changing the Path-26 allocation process to accommodate the CHP resources procured outside of IOUs service areas so that the IOUs can receive additional Path-26 allocations. Additionally, we clarify that this change being adopted is applicable to all resources submitted in the Path-26 netting process and not only CAM and CHP resource. The Path-26 allocation netting process is currently applicable to all resources and this would not change with this proposal.

CAC and CCC's requests that the increased transfer capability produced from netting be used exclusively to ensure delivery of CHP resources and any CHP resources in excess of the netting be exempt from Path-26 are not reasonable. First, all resources, not just CAM and CHP resources, are currently eligible to participate in the Path-26 netting process. Therefore, it is not possible and would be inequitable to specify that the netting benefits be used exclusively for CAM and CHP resources. Second, there is no exemption made for any other preferred resource as it relates to Path-26 and giving CHP resources that exemption would be discriminatory.

SDG&E's recommendation that in instances where CHP contracts are not able to receive the benefits of netting they get treated as a grandfathered contract in the earlier steps of the Path-26 process is also not reasonable. Since grandfathered contracts are considered in the baseline allocation, which takes place before the netting determination, it is not possible to go back and repeat the baseline allocation after the netting determination has occurred. Additionally, the out of zone CHP contracts are not grandfathered contracts and we see no compelling need to craft this exclusion at this time.

AReM's request to have the language regarding grandfathered contracts remain in Step 4, in order to ensure non-discriminatory allocation of Path-26, is not reasonable. The grandfathered contract language in Step 4 may prevent the IOUs from receiving the net benefits associated with the CAM and CHP contracts. In adopting this proposal we are trying to incent LSEs to utilize the netting step in order to maximize the Path-26 transfer capability; keeping the grandfathered contract language inhibits this incentive.

Further implementation details will be worked out as Energy Division develops the 2015 RA Compliance Templates and Guide in July 2014. Parties will have the opportunity to participate in the annual workshop held by Energy Division that discusses RA compliance materials for the upcoming year.

6.2. Schedule Outage Replacement Rule and Standard Capacity Product Mechanisms for Cost Allocation Mechanism Resources and Combined Heat and Power

The CAISO's scheduled outage replacement rule requires LSEs and generators to manage scheduled outages if the CAISO determines replacement capacity is needed. The replacement obligation falls on the Scheduling Coordinator for the LSE if the outage is scheduled at least 45 days prior to the compliance month. The replacement obligation falls on the Scheduling Coordinator for the resource if the outage is scheduled after 45 days prior to the compliance month.

LSEs are able to manage scheduled outages through their RA filings (i.e., LSEs include the replacement resource in their RA plans). The CAISO's Interface for Resource Adequacy alerts LSEs if a unit is on planned outage and if replacement capacity is needed. If the LSE does not manage the outage, and the CAISO determines that it needs replacement capacity for system reliability, the CAISO has the authority to procure backstop capacity through its Capacity Procurement Mechanism (CPM) and to recover the procurement costs from the customers within the TAC area.

Currently, CAM and CHP resources are not subject to the CAISO's scheduled outage replacement rule because these resources are treated as credits towards meeting RA requirements (i.e., they are not listed as physical resources on RA filings) and there is no mechanism to require the LSEs to replace power that does not show up on in their RA filings.

The Staff RA Refinement Proposal would have the IOU responsible for the CAM or CHP procurement also be responsible for the outage replacement of these resources. The forced or planned replacement for a CAM or CHP resources should first be managed with resources owned or managed by the IOU (the costs to be determined). If there are no resources managed by the IOU that can serve as replacement capacity, the IOU may need to procure additional RA resources specifically for purposes of replacement; this will create additional costs for the IOU that manages the CAM or CHP resource. The IOU would be given the authority to recover any outage replacement costs through the balancing account mechanism. Additionally staff proposes that the IOUs be required to economically bid the facilities as Flexible RA into the CAISO market to the fullest extent possible.

Parties' response to the staff proposal was mixed, with most parties seeking changes or clarifications. On April 4, 2014, a revised Staff RA Refinement Proposal was issued. The revised Staff RA Refinement Proposal recommends that IOUs utilize least-cost-best-fit evaluation for the replacement process of scheduled outages for CAM and CHP resources. The average capacity price from the most recent RA report would be used to recover replacement costs when IOU portfolio resources are used for replacement. All replacement costs that are the responsibility of the Scheduling Coordinator for the LSE would be recoverable through the balancing account mechanism.

SCE supports the revised Staff RA Refinement Proposal with clarifications. SCE recommends that the IOUs have the flexibility in their RA showings to list a "like" resource instead of the CAM resource. SCE also supports this proposal as long as there is a common understanding as to how to perform the credit and debit calculation, and the RA obligation is defined as the quantity including the system 15% planning reserve margin.

AReM is concerned that if the IOUs are given the flexibility to manage the CAM resources in their bundled customer's portfolios, as proposed by SCE, then this would shift costs from bundled customers to direct access customers. AReM recommends if the IOUs opt to not show the CAM resources then the IOU should verify with the other benefiting Energy Service Provider (ESPs) that the CAM resource substitution is acceptable.

PG&E supports the revised Staff RA Refinement Proposal with two refinements: 1) import RA contracts should not be incorporated into the determination of the price for replacement RA; and 2) the actual price paid for replacement RA should be used when the IOU must procure RA from the market to replace a CAM or CHP resource during its scheduled outage.

SDG&E opposes using the most recent RA price report because the most recent report is outdated and only reflects some and not all RA transactions. Alternatively, SDG&E recommends using the CAISOs CPM price because the CPM price more accurately reflects the IOUs portfolio of local resources. Also, SDG&E argues that it is not clear at which point costs of procuring the replacement can be shared with benefiting LSEs. SDG&E notes that not all planned outages require replacement; there are times where the IOU may anticipate an obligation in advance. Further, SDG&E recommends that a final rule adopting the revised Staff RA Refinement Proposal clarify the circumstances under which replacement costs will be borne by all potentially benefiting entities.

AReM does not support SDG&E's proposal to recover anticipated replacement costs before specific details are addressed. SCE agrees with SDG&E's request for clarification and proposes that once a LSE is informed by the CAISO of the need to provide replacement capacity, the Energy Division's proposed cost recovery will apply to the LSE's associated replacement capacity decisions.

AReM believes the revised Staff RA Refinement Proposal is workable. However AReM does not support using the average capacity price from the most recent RA report as the purchase price of capacity. AReM states that non-IOU customers should pay no more than what the IOU actually spends to replace the capacity that must be replaced. AReM also notes that recoverable replacement costs should be no more than the average RA price from the report.

SCE argues that their potential replacement resource mix includes tolling agreements, utility owned generation and CHP contracts. The RA value is not explicit in some of these contracts. SCE claims if the Commission adopts an "actual cost" method for the entire portfolio held by an IOU, then there would need to be an assessment as to the "actual costs" of capacity from resources for which there is no documentation (contractually or otherwise) as to the resource's specific RA value. SCE also states that the RA pricing report is an acceptable tool for pricing capacity when the IOU is using their portfolio of resources as replacement capacity. SCE proposes that if the IOU has to go to the market to procure replacement capacity then the actual costs of the replacement should be recoverable. If the market does not provide the sufficient replacement capacity and the CAISO has to backstop then the CPM price should be used.

CAC and CCC argue that QF/CHP contracts with CHP resources are unit contingent. CAC and CCC claim that in its approval of the CAISO's outage replacement rule FERC ruled that unit contingent resources do not have an obligation to deliver the energy separate from the energy delivered to the host and provide resource adequacy capacity as a part of that generation. CAC and

CCC request that the revised Staff RA Refinement Proposal be further revised to clarify that the Scheduling Coordinator of the resource will be responsible for outage replacement to the extent required by the contract between the parties, by FERC order, and by CAISO tariff rules.

The CAISO does not support CHP parties' proposed language modification. The CAISO argues that CHP Parties' comments appear to incorrectly suggest that FERC exempted CHP facilities from the replacement rule requirement because they are unit contingent. The CAISO claims that FERC disagreed that the CHP resources should be exempt from the Replacement Requirement because of penalties or obligations contained in their contracts, and that FERC states that provisions negotiated as part of a third party contract should not exempt CHP resources from their obligations under the Tariff.

CAISO proposes a clarification to the revised Staff RA Refinement Proposal so that it states: "For scheduled outages that are approved after the compliance filing due date, the Scheduling Coordinator of the resource will still be responsible for outage replacement to the extent required by the CAISO tariff rules and FERC orders."

TURN finds the revised Staff RA Refinement Proposal to be reasonable, but believes that setting costs for purchases of replacement capacity needs more development. TURN recommends the Commission adopt this proposal now in principal and decide these implementation issues later this year.

6.2.1. Discussion

We will adopt the revised Staff RA Refinement Proposal. There is reliability value gained from a mechanism that will allow the CAISO scheduled outage replacement rule to be fully implemented on CAM and CHP resources. Additionally, approval of the proposal potentially reduces the risk of costly back stop procurement. The magnitude of CAM and CHP resources will only continue to rise and there will be greater urgency to ensure the replacement rule is able to be applied to CAM and CHP resources the same way it is applied to other resources that don't utilize a CAM treatment.

The Staff RA Refinement Proposal would help mitigate the Path-26 constraint issue. Additionally, it is appropriate for the procuring IOU to manage the necessary scheduled outage replacement of the resource because they have greater insight into the costs associated with managing the risk of replacement for scheduled outage of CAM and CHP resources. Finally, we find that it is equitable and fair that the replacement costs associated with the scheduled outage replacement rule be recoverable through the CAM or CHP resources balancing account, when the obligations for replacement falls on the Scheduling Coordinator for the LSE. However it is not reasonable or fair that the Scheduling Coordinator for the resource or the contract counterparty also be able to recover replacement cost.

With respect to the capacity price used to recover scheduled outage replacement costs, we will adopt SCE and PG&E's proposed modification that allows the IOU to recover the actual costs of replacement if the IOU has to go to the market to procure. Additionally if the IOU is unable to procure in the market and the ISO has to perform backstop associated with the replacement then the IOU can recover the CPM costs of that replacement.

We agree with PG&E that import capacity prices should not be used in determining the average capacity price. The current 2012 RA report, issued on

April 23, 2014,[12] includes a price analysis that does not include import capacity prices. Future RA reports will also report aggregated capacity prices without imports. The price analysis includes average capacity prices by zone and local area which reflect the market prices of capacity covering 2012-2016 compliance months. We believe that these recently published capacity prices reflect the cost of IOU portfolio capacity replacement more so than the CPM price as proposed by SDG&E.

We agree with SDG&E that the circumstances under which replacement costs will be borne needs to be clarified. We adopt SCE's clarification that once a LSE is informed by the CAISO of the need to provide replacement capacity, the Energy Division's proposed cost recovery will apply to the LSE's associated replacement capacity decisions.

SCE's proposed modification -- regarding IOU's management of their CAM and CHP resources flexibly in order to exercise least-cost best-fit -- is reasonable. However we do not agree that the IOUs should be able to recover scheduled outage replacement costs for "like" CAM and CHP resources shown in their RA filings. We agree with AReM that adopting this modification could lead to cost shifting from bundled customers to direct access customers. Therefore, IOUs will be given the flexibility to manage their CAM and CHP resources in their RA filings however scheduled outage replacement costs will only be recoverable for CAM and CHP resources, not "like" resources.

SCE's and PG&E's requested assurance that the "RA obligation" includes the 15% planning reserve margin is the current practice of the RA program.

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[12] http://www.cpuc.ca.gov/NR/rdonlyres/94E0D083-C122-4C43-A2D2-B122D7D48DDD/0/2012RAReportFinal.pdf

CAM credits are taken out after the 15% planning reserve margin is applied. This practice will continue with the adopted proposal.

CAC and CCC request the revised staff proposal be changed to state: "for scheduled outages that are approved after the compliance filing due date, the Scheduling Coordinator of the resource will be responsible for outage replacement to the extent required by the contract between the parties, by FERC order, and by CAISO tariff rules." We will not adopt this change. We agree with the CAISO that CHP facilities are not exempt from the replacement rule, and that including the language "to the extent required by the contract" implies that a Scheduling Coordinator for the resource may be exempt from the replacement rule. We will adopt the CAISO proposed language that says "for scheduled outages that are approved after the compliance filing due date, the Scheduling Coordinator of the resource will still be responsible for outage replacement to the extent required by the CAISO tariff rules and FERC orders."

Further implementation details will be worked out as Energy Division develops the 2015 RA Compliance Templates and Guide in July 2014. Parties will have the opportunity to participate in the annual workshop held by Energy Division that discusses RA compliance materials for the upcoming year.

6.3. Allocation of Flexible Capacity for CAM and CHP Resources

The CAM adopted in D.06-07-029[13] as well as the cost treatment adopted in the CHP settlement states the rights to the capacity be allocated out to LSEs in

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[13] D.06-07-029, Ordering Paragraph 1 states: "The LSEs in the IOUs' service territory will be allocated rights to the capacity that can be applied toward each LSE's resource adequacy (RA) requirements. The LSEs' customers receiving the benefit of this additional capacity pay only for the net cost of this capacity, determined as a net of the

Footnote continued on next page

exchange for paying the net capacity costs (cost of the purchasing power agreement minus energy revenues).

In D.13-06-024 the Commission adopted a flexible capacity framework which defines a flexible capacity product as well as flexible capacity requirements that would be mandatory beginning in 2015.[14]

Historically Energy Division has allocated the local benefits of CAM resources annually. The annual allocation is done by reducing the Local RA requirement(s) by the amount of Local RA benefit provided by each CAM resource. The annual allocation is initially done in July and then again in September. Starting with the 2011 Compliance year, Energy Division began implementing a local true-up process (adopted in D.10-12-038). The true-up methodology allowed for the reallocation of the local benefits of CAM twice during the compliance year.

Staff proposes that the same allocation methodology currently used for the allocation of Local RA CAM benefits be extended to the allocation of Flexible RA CAM benefits. Energy Division proposes to allocate the benefits only for the initial and final year-ahead allocations. In order to ensure accurate allocation of Flexible RA capacity to all benefiting customers, the IOUs would need to provide Energy Division with a complete list of all their committed flexible CAM resources prior to the July RA allocations. The EFC associated with each eligible flexible resource will be allocated to the service area paying for the resource.

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total cost of the contract minus the energy revenues associated with dispatch of the contract."

[14] D.13-06-024 Ordering Paragraph 5 and Appendix A at A1-A5.

Several parties provided suggestions and modifications to the Energy Division proposal. In response, on April 4, 2014 Energy Division issued a revised proposal that specified only CAM and CHP resources contractually able to provide committed flexible capacity be made available for flexible capacity allocation. Staff proposed that the allocation follow the timeline proposed by staff for Local RA. Finally, staff proposed if the scheduled outage replacement for CHP and CAM resources proposal is adopted, the flexible capacity be treated in the same manner detailed for local RA benefits in scheduled outage replacement for CHP and CAM resources proposal.

SCE supports staff's revised proposal. AReM believes the proposal is workable; however they argue that if the CAM resources RA benefit it not available to the ESPs because of a contractual dispute or an administrative issue, then the direct access customers should no longer be required to pay the associated CAM charges for the resource. SCE disagrees with AReM and states that it does not agree that a legitimate contractual dispute of a new regulatory requirement should be the basis to ex post declare the procurement to have occurred on behalf of bundled customers only. SCE adds that if it is determined that the contract does convey flexibility benefits, then such benefits will be allocated to all benefiting customers accordingly.

CAC and CCC stress the importance of clarifying the difference between a resources' capability to supply flexible capacity and the amount of flexible capacity it actually contracts to provide. Additionally CAC and CCC propose that the RA program require all new RA contracts to specify whether the capacity is generic or flexible and how it is to be scheduled.

6.3.1. Discussion

We adopt the revised Energy Division proposal to allocate the flexible benefits of CAM and CHP resources that are contractually able to provide committed flexible capacity. The timeline laid out in the yearly RA Compliance Guide compiled by Energy Division will be utilized to allocate the flexible capacity benefits of these resources.[15] All three IOUs shall submit a list of its CAM and CHP resources with contracted system and flexible capacity benefits of each resource to Energy Division prior to the allocation timeline laid out for local RA in the RA Compliance Guide.

SDG&E and AReM request that the allocation of flexible capacity for CAM and CHP resources consider the flexible categories being established at the CAISO. In this decision, we adopt the CAISO's flexible categories. Therefore, it is consistent to allocate flexible capacity for CAM and CHP resources consistent with the flexible categories adopted in this decision. Not doing so would result in misalignment between the CAISO's and the Commission's reliability programs.

CAC and CCC request, that the Commission require all new RA contracts to specify whether the capacity is generic or flexible and how it is to be scheduled, is not necessary at this time. It is reasonable to expect that the bilateral-market will be able to develop its own language with regards to flexibility and do not see the need at this time to require specific contract language.

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[15] Additionally. Energy Division will implement the allocation of the flexible capacity benefits consistent with its revised proposal regarding scheduled outage replacement for CHP and CAM resources.

Energy Division will further develop the allocation methodology as they develop the 2015 RA Compliance Templates and Guide during July 2014. Parties will have the opportunity to participate in the annual workshop held by Energy Division that discusses RA compliance materials for the upcoming year.

6.4. Local RA Refinement Proposals

In D.06-06-064, the Commission adopted local RA obligations, which require LSEs under Commission jurisdiction to procure and commit sufficient generation to the CAISO in Local Areas to meet Local RA needs. The Commission has adopted obligations on an annual basis ever since, and the Local RA program has evolved with policy development and annual revisions to procurement rules.

D.11-06-022 made permanent the aggregation of PG&E "other areas" into one Local Area, allowing procurement in any of those Local Areas to meet the total Other PG&E Areas Local RA obligation. PG&E's Greater Bay Area Local Area remained separate, as established in D.06-06-064. Aggregation into less granular Local Areas represents a tradeoff, however. If LSEs procure sufficient MW totals of Local RA resources, but the portfolio of Local RA resources procured does not meet reliability concerns due to subarea constraints or resource use limitations, there will be residual unmet local reliability needs. To ensure that the aggregated procurement adequately satisfies local reliability concerns, the CAISO analyzes procurement by all and publishes a report which lists any residual procurement required to remedy local reliability conditions.

LSEs receive an allocation of Local RA obligations in July of each year, which gives LSEs separate Local RA obligations in five Local Areas; two in PG&E's service territory, two in SCE's service territory, and one that covers the entirety of SDG&E's service territory. Because of a decision to partially reopen direct access in several "tranches" in 2010,[16] the Commission created a process to reallocate Local RA obligations twice a year, based on the schedule of direct access "tranches" included in the direct access process.[17] The Local RA reallocation process adopted in 2010 allowed LSEs to receive two incremental adjustments to their year-ahead Local RA procurement obligations. The incremental Local RA amounts can be either positive (if the LSE received load since the year-ahead allocation process) or negative (if the LSE lost load or if additional CAM resources came online).

The impacts of aggregation depend on the MW size of the procurement obligations (and indirectly on the size of the LSE, since Local RA allocations are based on peak load); thus it may be reasonable to allow further aggregation of Local RA year-ahead procurement obligations for smaller LSEs (5 MW of Local RA in one service territory for example) and not for larger LSEs. Aggregation of local RA obligations for larger LSEs would likely result in a greater chance of procurement that was too heavily weighted in one Local Area and did not resolve local reliability concerns.

On January 26, 2014 Energy Division proposed to alter allocation timelines and Local RA procurement requirements. Under Energy Division's proposal, LSEs with total Local RA obligations not exceeding 5 MW in any one IOU service territory would be allowed to aggregate their Local RA obligations into one Local Area in that service territory. In addition, Energy Division proposed to remove one of the two Local RA incremental allocations during the RA compliance year (meaning that there is only one chance to revise Local RA obligations after the

[16] D.10-03-022.

[17] D.10-12-038.

year ahead RA filing) and to reduce the frequency of CAM-RMR allocations during the RA compliance year from monthly to quarterly.

6.4.1. Parties' Comments

Parties either support Energy Division's proposals related to frequency of CAM-RMR allocations and removal of one of the Local RA incremental allocations or had no comment on the proposals. SCE requests that along with CAM-RMR allocations occurring quarterly, there would be efficiency benefit in conducting reallocations of flexible RA obligations at the same time.

Except for MCE, parties unanimously oppose the proposal to aggregate Local RA obligations in a service territory for LSEs with Local RA obligations not exceeding 5 MW total in a service territory. In particular, SCE, SDG&E, and ORA are concerned that this aggregation, although small, would cause a non-zero risk of backstop procurement due to misdirected Local RA procurement. PG&E and AReM cite equity and fairness concerns, claiming that the proposal treats certain LSEs more favorably than others,

6.4.2. Discussion

We are persuaded that Energy Division's proposals related to removal of one cycle of incremental Local RA allocations and moving to quarterly CAM-RMR allocations removes unnecessary complexity. We adopt Energy Division's proposals and order one incremental Local RA allocation, to occur in May and adjusting Local RA obligations for July compliance month through the end of the compliance year, starting with 2015 RA compliance. In addition, beginning with the January 2015 RA compliance month, Energy Division will reallocate CAM and RMR obligations quarterly. The first reallocations will be sent to LSEs in January 45 days before the RA filing is due for April 2015. Energy

Division staff will develop the details of implementation and notify parties via the annual RA Compliance Guide and via a workshop to be held in July 2014.

We do not adopt the last Energy Division proposal to aggregate Local RA obligations in an IOU service area where an LSE has a total Local RA obligation not exceeding 5 MW in any service area. We are convinced that the streamlining and efficiency benefits in this proposal are small.

6.5 Demand Response Counting Issues

Load Impacts for Critical Peak Pricing Programs

In D.11-06-022, Ordering Paragraph 14, the Commission allowed PG&E to receive load impacts averaged over the hours of 2 p.m. to 6 p.m. for their critical peak pricing programs DR programs, instead of the standard 1 p.m. to 6 p.m. interval over which load impacts are averaged for other DR programs. PG&E was ordered to "propose changes to the current large commercial and industrial and agricultural customers PDP [Peak Day Pricing] operational period of 2 p.m. to 6 p.m. to 1 p.m. to 6 p.m. in its 2012 Rate Design Window (RDW) application." PG&E has proposed the changes to the operational hours in compliance with the requirement for its critical peak pricing programs in its RDW application, which is still pending Commission's approval.

PG&E requests that their critical peak pricing programs continue to be averaged over the 2 p.m. to 6 p.m. time interval if a no 2012 RDW decision is issued. We will adopt PG&E's request.

7. Effective Load Carrying Capacity (ELCC) for Wind and Solar Resources

In Senate Bill (SB) 2 (1X), the CPUC was ordered to "determine the effective load carrying capacity of wind and solar energy resources on the

California electrical grid," and to "use those effective load carrying capacity values in establishing the contribution of wind and solar energy resources toward meeting […] resource adequacy requirements."[18]

ELCC is a percentage that expresses how well a resource is able to meet reliability conditions and reduce expected reliability problems or outage events (considering availability and use limitations). It is calculated via probabilistic reliability modeling, and yields a single percentage value for a given facility or grouping of facilities. ELCC can be thought of as a derating factor that is applied to a facility's maximum output (Pmax) in order to determine its QC. Because this derating factor is calculated considering both system reliability needs and facility performance, it will reflect not just the output capabilities of a facility but also the usefulness of this output in meeting overall electricity system reliability needs.

While ELCC calculations have been conducted for conventional resource types since the 1960s and are now also relatively well-understood for renewable resources, there can nevertheless be significant differences in implementation and the process remains complex. In order to address these issues and begin implementation of SB 2 (1X), the "[p]reparation and review of new studies of the effective load carrying capacity (ELCC) of wind and solar resources" was included in the scope of Phase 3 of the RA proceeding in the August 2, 2013 Scoping Memo.

7.1. The Energy Division Proposal

Energy Division's proposal titled *Effective Load Carrying Capacity and Qualifying Capacity Calculation Methodology for Wind and Solar Resources* was

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[18] *See* http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.html, SEC. 28, Section 399.26 (d).

discussed at the January 27, 2014 RA Workshop. Staff also issued initial documentation of probabilistic modeling inputs and assumptions. The calculation methodology proposal covered the ELCC concept and literature review, calculation granularity and other methodological details, a formula to yield a QC based on an ELCC, and possible future refinements.

7.2. Parties' Positions

Many parties request that implementation be delayed by one year to allow parties to see the probabilistic modeling results, iterate with CPUC staff on the ELCC modeling, and further consider its implications prior to adoption of an ELCC calculation methodology or ELCC-based QC values. This position is taken by ORA, the CAISO, PG&E, SCE, TURN and NRG, and is "not opposed" by Calpine. CalWEA is opposed to this delay.

Additionally, parties raised several technical and policy considerations in need of further discussion, such as increasing the level of granularity to incent beneficial design choices and avoid over- or under-procurement, addressing whether ELCC values should be locked in for existing/new facilities and contracts or whether they may change over time, determining the hours that should be considered for ELCC calculation, and inclusion of a diversity benefit.

7.3. Discussion

While we appreciate the need to comply with the requirements of SB 2 (1X) as quickly as possible, we agree with parties that many issues remain to be resolved prior to Commission adoption of an ELCC model and ELCC-based QC values for wind and solar resources. Most importantly, the current schedule no longer allows sufficient time for vetting and iteration. Therefore, we do not adopt an ELCC-based QC methodology for wind or solar resources at this time.

Because we are not adopting an ELCC-based QC methodology at this time, the QC values for wind and solar resources shall be determined for 2015 according to the exceedance methodology adopted in D.09-06-028 (*see* Appendix B of D.09-06-028). However, in light of the importance of complying with SB 2 (1X), we direct Energy Division to further develop its ELCC proposal and address the issues identified above such that an ELCC-based QC methodology can be considered by the end of 2014. We understand that this methodology may be only a first iteration in addressing the complex technical issues associated with ELCC calculations, and that the methodology may require additional refinement over time.

8. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on June 16, 2014, and reply comments were filed on June 23, 2014. The proposed decision was modified to account for comments.

9. Assignment of Proceeding

Michel P. Florio is the assigned Commissioner and David M. Gamson is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The assumptions, processes, and criteria used for the CAISO 2014 Local Capacity Requirements study were discussed and recommended in a CAISO stakeholder meeting, and they generally mirror those used in the 2007 through 2013 Local Capacity Requirements studies.

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

3. As determined by D.13-06-024, there is a need for refinements to the RA program to further define elements of flexibility, as grid operations and reliability may suffer without sufficient resources capable of reducing ramping needs or being flexibly dispatched.

4. The revised Staff Flexible Capacity Proposal takes into consideration the CAISO's FRAC-MOO proposal and issues brought up by parties in workshops and comments.

5. The adoption of a flexible capacity requirement as part of the resource adequacy program will help ensure that flexible capacity is operationally available to the CAISO to maintain grid reliability.

6. It is important to minimize differences between the Commission's Flexible Capacity Requirements and the CAISO's FRAC-MOO proposal in order to provide certainty in the marketplace. However, perfect alignment may not be possible because the FRAC-MOO proposal is not final or approved by FERC.

7. There is sufficient overall flexible capacity in the CAISO Balancing Authority Area to meet flexible capacity needs in 2015. However, there is not necessarily sufficient flexible capacity under contract by LSEs, or the certainty that contracted flexible capacity supplies will bid into the market, to meet all flexible capacity needs.

8. The flexible capacity needs identified by the CAISO for 2015 increased from those identified for 2014, but did not increase by the amount forecasted from the CAISO's 2013 study, primarily because fewer renewable resources are expected to be brought on line before or during 2015.

9. Variable energy capacity is lower in the CAISO's 2014 estimates than what the CAISO expected in 2013 estimates.

10. The use of flexible capacity seasonal categories as proposed by the CAISO strikes a balance between reliability, administrative ease, and accurate levels of procurement.

11. Imposing a flexible capacity requirement will increase ratepayer costs by an unknown amount, but the overall excess of flexible capacity supply over flexible capacity need infers that cost increases will not be excessive.

12. Filling the need for flexible capacity in order to ensure reliability provides an important benefit to ratepayers.

13. The CAISO calculated flexible capacity needs for 2015 based on the methodology adopted in D.13-06-024.

14. In the RA program, system capacity is allocated to Load Serving Entities using the load-ratio share method.

15. SDG&E's unbundling proposal is complex and may have unintended consequences.

16. CHP resources have unique operating requirements related to industrial host obligations, and the EFC should reflect such requirements.

17. System reliability need identified in the Long Term Procurement Planning proceeding is specific to the service area of each IOU.

18. Decision (D.)06-07-029 of the LTPP proceeding adopted a Cost Allocation Mechanism to allow IOUs to allocate the costs and benefits of certain new generation resources to all benefiting customers within their service areas.

19. The Qualify Facility and CHP settlement, adopted in D.10-12-035, established a cost treatment to be used to share the benefits and the costs associated with meeting the CHP and greenhouse gas goals.

20. In the last year, the IOUs' CHP requests for offers have resulted in procurement outside the IOUs' TAC service areas; in this situation, the RA benefits to the TAC IOUs' service area are limited by Path-26 constraints.

21. Allocating CHP RA credit to LSEs in one TAC service area for resources procured in another TAC service area can be problematic for the following reasons: 1) It does not consider the Path-26 system constraint, 2) Local costs are not equitably allocated, in that customers in one service TAC area are paying for reliability benefits in another area, and 3) It creates another level of complexity in procurement planning that is not transparent to LSEs that serve DA and CCA load.

22. While CHP resources have unique operating requirements related to industrial host obligations, CHP resources use the same technology as thermal resources but their specific unique operating requirements set them apart from conventional thermal resources.

23. In order to ensure that supply-side demand response resources can perform at their qualifying capacity levels, such resources must be tested regularly.

24. Testing for demand response resources needs to balance the practical needs of resources operators with the functional requirement to verify performance in real world situations.

25. The CAISO's proposal that all bi-directional resources must register as non-generation resources may be unduly restrictive, and does not allow for bi-directional demand response resources.

26. The CAISO's scheduled outage replacement rule requires LSEs and generators to manage scheduled outages if the CAISO determines replacement capacity is needed.

27. The obligation for replacement associated with the scheduled outage replacement rule falls on the Scheduling Coordinator for the LSE when the outage is scheduled at least 45 days prior to the compliance month.

28. The Scheduling Coordinators for LSEs are able to manage scheduled outages through the LSEs' RA filings.

29. Currently, CAM and CHP resources are shown as a credit in LSEs' RA filings, not as a resource.

30. CAM and CHP resources are not subject to the CAISO's entire scheduled outage replacement rule because these resources show up as a credit and not a resource in the LSEs' RA filings.

31. In order for the CAISO scheduled outage replacement rule to be fully implemented, CAM and CHP resources need to be shown as resources in the RA filing.

32. There is reliability value gained from adopting a mechanism that will allow the CAISO scheduled outage replacement rule to be fully implemented for CAM and CHP resources.

33. Reducing the risk of backstop procurement by the CAISO will benefit ratepayers.

34. The procuring IOU has greater insight into the costs associated with managing the risk of replacement for scheduled outage of CAM and CHP resources.

35. Negative and bi-directional resources are capable of contributing to meeting system ramping needs.

36. Bi-directional resources, including demand response or storage resources, may have a discontinuity when crossing from negative to positive generation, may take varying amounts of time (up to and possibly more than 45 minutes) to make this transition.

37. Allowing a transition time, such as a 45-minute transition time, for bi-directional resources crossing from negative to positive generation may have unforeseen grid reliability impacts and requires further analysis.

38. Load impact protocols are already successfully in place for retail demand response, and alternatives have been insufficiently vetted for supply side demand response.

39. The EFC and QC of supply-side demand response resources need to incorporate the results of actual dispatches and/or be determined via testing lasting at least two hours.

40. The Energy Division proposal to allow demand response providers to select a three-month window for testing of Flexible RA resources (or to choose a precise test date and time in advance for System/Local RA) needs to be reconciled with CAISO tariffs as they develop.

41. Many issues remain to be resolved regarding an ELCC model and ELCC-based QC values for wind and solar resources. These issues include consideration of approaches to increase technological and regional ELCC granularity; determination of whether ELCC values should be locked in for

certain facilities or contracts, and if so under what circumstances; and several other technical questions such as the potential inclusion of a diversity benefit.

42. The ELCC model is not yet complete and model results have not yet been published.

Conclusions of Law

1. The CAISO's 2014 Local Capacity Technical Analysis Final Report and Study Results should be approved as the basis for establishing local procurement obligations for 2015 applicable to Commission jurisdictional LSEs.

2. The revised Staff Flexible Capacity Proposal to adopt a detailed flexible capacity program as part of the RA program for RA years 2015 through 2017 must be considered in light of comments by parties on this proposal.

3. The revised Staff Flexible Capacity Proposal, as modified herein in light of comments, is reasonable to adopt for a detailed flexible capacity program as part of the RA program for RA years 2015 through 2017.

4. It is reasonable to impose flexible obligations to ensure that LSEs contract for flexible resources and bid them into the CAISO market.

5. It is reasonable to adopt the CAISO proposed seasonal flexible categories.

6. Flexible capacity should be allocated to Load Serving Entities using the load-ratio share method in 2015, but should be reconsidered for future RA years.

7. SDG&E's unbundling proposal should not be adopted at this time, but should be considered in the next RA proceeding.

8. The Energy Division revised proposal for determining the QC of storage resources is reasonable, on an interim basis.

9. The CAISO recommendation for counting the effective flexible capacity of a CHP resource as the minimum of the net qualifying capacity, or Pmax minus Pmin, is reasonable.

10. In order for energy storage and supply-side demand response to receive credit for their contributions to resource adequacy, it is necessary for them to receive net qualifying capacity and effective flexible capacity values. However, these resources may have different operating characteristics than conventional resources in certain areas.

11. Consistent with D.13-06-024, flexible capacity procurement obligations should be established for all Commission jurisdictional load serving entities for 2015.

12. The CAISO's Final 2014 Flexible Capacity Needs Assessment should be approved as the basis for establishing local procurement obligations for 2015 applicable to Commission jurisdictional LSEs.

13. Energy Division should implement the RA program for 2015 in accordance with the adopted policies in this and previous decisions.

14. It is reasonable to impose a new requirement on LSEs for flexible capacity starting in the 2015 RA year.

15. It is reasonable to cause increased ratepayer costs by imposing a flexible capacity requirement starting in 2015 because there will be commensurate or greater benefits from improved reliability.

16. The Energy Division's revised April 9, 2014 proposal entitled "Qualifying Capacity and Effective Flexible Capacity for Energy Storage and Supply-Side Demand Response Resources" is reasonable as modified in Appendix B, and should be adopted.

17. The Energy Division proposal that testing for Flexible RA resources is required if it occurs during a three-month window specified by the demand response provider is generally reasonable. However, this proposal should be modified so that, if the CAISO sets a more stringent requirement (such as testing

randomly selected to occur at any time within the resource's availability period), that testing will be required instead.

18. It is not reasonable at this time, without further analysis, to allow bi-directional resources any transition time between positive and negative generation if they are to qualify as flexible RA resources.

19. It is not reasonable at this time, without further analysis, to adopt the CAISO's proposal to require bi-directional resources to register as non-generator resources.

20. It is reasonable to adopt the existing LIPs as the basis for determining the QC and EFC of supply-side demand response in the 2015 RA compliance year on an interim basis.

21. The Energy Division proposal that CHP resources procured outside of an IOUs' north or south zone be required to be included in the Path-26 netting process is reasonable.

22. The Energy Division proposal that IOUs utilize least-cost-best-fit evaluation for the replacement process of scheduled outages for CAM and CHP resources is reasonable.

23. It is reasonable the IOUs be given the flexibility to manage their CAM and CHP resources for scheduled outages.

24. It is reasonable that the replacement costs associated with the scheduled outage replacement rule, when the replacement obligation falls on the scheduling coordinator for the LSE, be recoverable through the CAM or CHP resources balancing account. It is not reasonable that the Scheduling Coordinator for the resource or the contract counterparty also be able to recover replacement cost.

25. It is reasonable that the recoverable replacement cost for resources used from the IOUs portfolio be determined using the average capacity price from the most recent RA report.

26. It is reasonable that the actual price paid for replacement capacity be used to determine the replacement costs when the IOU must procure replacement capacity in the market.

27. It is reasonable that the CPM price of capacity be used to determine replacement costs if the IOU is unable to find replacement capacity and the CAISO exercises back stop procurement.

28. It is reasonable that the average capacity price not include import prices.

29. It is reasonable that replacement costs for CAM and CHP resources should be borne by the LSE once the LSE has been informed by the CAISO that replacement capacity is needed.

30. The Energy Division proposal to allocate the flexible benefits of CAM and CHP resources that are contractually able to provide committed flexible capacity is reasonable.

31. Energy Division's proposals to remove of one cycle of incremental Local RA allocations and move to quarterly CAM-RMR allocations remove unnecessary complexity, and streamlines RA program implementation.

32. The SB 2 (1X), requirement to "determine the effective load carrying capacity of wind and solar energy resources on the California electrical grid," and to "use those effective load carrying capacity values in establishing the contribution of wind and solar energy resources toward meeting […] resource adequacy requirements" must be complied with as soon as practicable.

33. Because many technical issues remain unresolved, it is not practicable to meet the SB 2 (1X) requirements regarding ELCC for wind and solar resources at

this time. To comply with statutory requirements, these issues should be resolved before the next yearly RA decision, if possible.

34. As an interim measure, it is reasonable for the QC values for wind and solar resources to be determined according to the current exceedance methodology for 2015.

35. PG&E's request that their critical peak pricing programs continue to be averaged over the 2 p.m. to 6 p.m. time interval is reasonable.

O R D E R

IT IS ORDERED that:

1. The California Independent System Operator's 2015 Local Capacity Technical Analysis Final Report and Study Results, filed May 1, 2014, is adopted as the basis for establishing local procurement obligations for 2015 applicable to Commission-jurisdictional Load Serving Entities as defined by Public Utilities Code Section 380(j).

2. The "Option 2/Category C" Local Capacity Requirements set forth in the California Independent System Operator's 2015 Local Capacity Technical Analysis Final Report and Study Results, filed May 1, 2014, 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 2015 are as follows:

	2015 LCR Need Based on Category C with Operating Procedure		
Local Area Name	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**
Humboldt	166	0	166
North Coast / North Bay	550	0	550
Sierra	1803	397	2200
Stockton	396	311	707
Greater Bay	4231	136	4367
Greater Fresno	2393	46	2439
Kern	411	26	437
LA Basin	9097	0	9097
Big Creek/ Ventura	2270	0	2270
San Diego/Imperial Valley	3910	202	4112
Total	25227	1118	26345

3. The local resource adequacy program and associated requirements adopted in Decision (D.) 06-06-064 for compliance year 2007, and continued in effect by D.07-06-029, D.08-06-031, D.09-06-028, D.10-06-036, D.11-06-022,

D.12-06-025, and D.13-06-024 for compliance years 2008 through 2014, respectively, are continued in effect for compliance year 2015, subject to the modifications, refinements, and local capacity requirements adopted in ordering paragraphs in this decision.

4. The California Independent System Operator's Final 2014 Flexible Capacity Needs Assessment, filed May 1, 2014 (as amended by a May 5, 2014 filing), is adopted as the basis for establishing flexible procurement obligations for 2015 applicable to Commission-jurisdictional Load Serving Entities as defined by Public Utilities Code Section 380(j), consistent with the flexible capacity framework adopted in Decision 13-06-024. The Flexible Capacity Requirements for 2015 are as follows:

NOTE: All numbers are in MegaWatts	CAISO System Flexible Requirement	CPUC Flexible Requirement	Category 1 (minimum)	Category 2 (100% less Cat. 1 & 3)	Category 3 (maximum)
January	9,459	8,972	6,639	1,884	449
February	10,465	10,099*	7,473	2,121	505
March	9,543	9,025	6,679	1,895	451
April	8,468	8,005*	5,924	1,681	400
May	7,520	7,134*	4,851	1,926	357
June	9,078	8,707	5,921	2,351	435
July	8,083	7,694	5,232	2,077	385
August	7,861	7,464*	5,076	2,015	373
September	8,523	8,126	5,526	2,194	406
October	10,381	9,818*	7,265	2,062	491
November	10,848	10,460	7,740	2,197	523
December	11,212	11,035	8,166	2,317	552

5. The Resource Adequacy (RA) program is modified for the RA compliance years 2015 through 2017 pertaining to flexible capacity as set forth in Appendix A.

6. The Resource Adequacy (RA) program pertaining to Qualifying Capacity and Effective Flexible Capacity for Energy Storage and Supply-Side Demand Response Resources is modified for the RA compliance years 2015 through 2017 as set forth in Appendix B.

7. Each Load Serving Entity (LSE), as defined by Public Utilities Code Section 380(j), shall make a year-ahead and month-ahead showing of flexible capacity for each month of the compliance year. In this showing, each LSE shall report all of its committed flexible resources to meet the LSE's flexible capacity procurement requirement for 2015.

8. If Southern California Edison Company, Pacific Gas and Electric Company and/or San Diego Gas & Electric Company are responsible for combined heat and power procurement outside of their service area zone, they shall submit the contract information for such procurement to the California Independent System Operator as an existing contract in the Path-26 netting process adopted in Decision 07-06-029.

9. The Resource Adequacy program is modified so that additional available Path-26 capacity created by the netting of existing contracts shall be allocated to load-serving entities (LSEs) based on the LSE's netting participation-ratio share, and shall no longer be based on LSEs' load-ratio.

10. The flexible benefits of Cost Allocation Mechanism (CAM) resources and combined heat and power (CHP) resources that are contractually able to provide committed flexible capacity shall be allocated among benefiting Electric Service Providers. Southern California Edison Company, Pacific Gas and Electric Company and San Diego Gas & Electric Company shall submit a list of its CAM and CHP resources with contracted system and flexible capacity benefits of each

resource to Energy Division prior to the Resource Allocation timeline detailed in the Commission's Resource Adequacy compliance guide.

11. Southern California Edison Company, Pacific Gas and Electric Company and San Diego Gas & Electric Company shall manage their procured Cost Allocation Mechanism and combined heat and power resources, consistent with least-cost best-fit evaluation, for scheduled outages when the California Independent System Operator's scheduled outage replacement rule falls on the scheduling coordinator for load serving entities.

12. Southern California Edison Company, Pacific Gas and Electric Company and San Diego Gas & Electric Company (the IOUs) are authorized to recover scheduled outage replacement costs associated with their procured Cost Allocation Mechanism (CAM) and combined heat and power (CHP) resources when the replacement obligation (as written in the California Independent System Operator scheduled outage replacement rule tariff) falls on the scheduling coordinator for the load serving entity. The scheduled outage replacement costs will be recoverable through the CAM or CHP resources balancing account. The recoverable cost of replacement capacity for CAM and CHP resources shall be as follows:

(i) For replacement with IOU portfolio resources (resources already under contract or owned by the IOU), the average capacity price from the most recent Energy Division Resource Adequacy report shall be used to determine the recoverable costs.

(ii) For replacement with capacity procured in the market, the actual capacity price paid shall be used to determine the recoverable costs.

(iii) For replacement capacity that is unavailable in the market and for which CAISO exercises backstop authority using its capacity procurement mechanism

(CPM), the CPM price shall be used to determine the recoverable costs.

13. Any Load Serving Entity (LSE) which seeks to show a supply-side demand response resource in its RA compliance filings shall provide evidence of resource performance at least once per calendar year. If the resource is dispatched by the California Independent System Operator (CAISO) for at least two consecutive hours, the dispatch will meet this requirement. Otherwise, the LSE must provide test results. Testing must comply with the requirements detailed in Appendix B to this decision. If the CAISO sets a testing requirement that meets these criteria, then this testing will be required. Otherwise, the LSE must conduct the testing. Demand response providers may select the date and time of testing for System and Local Resource Adequacy resources. For Flexible Resource Adequacy resources, the demand response provider may select a three-month testing window, with the precise date and time randomly selected by the LSE. Compensation shall occur according to the applicable CAISO tariff.

14. Qualifying capacity values for wind and solar resources shall be determined for 2015 according to the exceedance methodology adopted in Decision 09-06-028.

15. The Resource Adequacy program is modified so that Energy Division shall perform one incremental Local Resource Adequacy (RA) allocation, to occur in May and adjust Local RA obligations for July compliance month through the end of the compliance year, starting with 2015 RA compliance. Beginning with the January 2015 RA compliance month, Energy Division shall reallocate Cost Allocation Mechanism and Reliability Must Run obligations quarterly, to be sent to Load Serving Entities in January, 45 days before the RA filing is due for April 2015. Energy Division shall develop the details of implementation and

notify parties via the annual RA Compliance Guide and via a workshop to be held in July 2014.

16. Southern California Edison Company, Pacific Gas and Electric Company and San Diego Gas & Electric Company shall each submit a list of their Cost Allocation Mechanism resources and combined heat and power resources with contracted system and flexible capacity benefits of each resource to Energy Division prior to the allocation timeline laid out for local Resource Adequacy (RA) in the RA Compliance Guide.

17. Pacific Gas and Electric's critical peak pricing programs shall continue to be averaged over the 2 p.m. to 6 p.m. time interval.

18. Rulemaking 11-10-023 is closed.

This order is effective today.

Dated June 26, 2014, at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
MICHAEL PICKER
Commissioners

APPENDIX A

APPENDIX A
ADOPTED FLEXIBLE CAPACITY PROCUREMENT FRAMEWORK

Section I. Background

The California Public Utilities Commission ("CPUC") and the California Independent System Operator ("ISO") agree that securing operational flexibility is critical due to the increasing influx of intermittent supply resources and changing load patterns. The CPUC's Long Term Procurement and Planning ("LTPP") and Resource Adequacy ("RA") Proceedings are the primary mechanisms that ensure California's investor owned utilities ("IOUs") and energy service providers ("ESPs") have adequate generation capacity. The RA process requires load-serving entities ("LSEs") to demonstrate that they have procured sufficient generation capacity to meet the upcoming year's forecast demand. The objective of the flexible RA procurement initiative is to ensure that LSEs purchase capacity from generators with suitable operational characteristics and make this capacity operationally available to the ISO by economically bidding in these resources in the ISO day-ahead and real time markets.

Decision ("D.")12-06-025 directed parties to define "flexibility" and develop implementation details for incorporating flexible capacity in the 2014 RA program. As part of the directive, the ISO and two of the three IOUs submitted a proposal, "Resource Adequacy and Flexible Capacity Procurement Joint Parties' Proposal" ("Joint Proposal") on October 29, 2012 to the Energy Division. The Joint Proposal recommended that the Commission establish a monthly "flexible capacity procurement" requirement among LSEs. D.13-06-024 adopted an interim flexible capacity framework for the years 2014-2017. The Decision adopted flexible capacity targets for LSEs in 2014 with direction to adopt flexible capacity requirements in 2015. The Decision further outlined certain tasks that needed to be completed to enforce flexible capacity requirements on LSEs.

The ISO initiated its own stakeholder process and issued a series of straw proposals to propose additions to ISO tariff essential to the implementation of the flexible RA framework. The last version was the "Flexible Resource Adequacy Criteria and Must-offer Obligation" straw paper ("FRAC-MOO proposal") issued on March 7, 2014.

Section II. Flexible capacity need and allocation

D.13-06-024 recognized a need for flexible capacity in the RA fleet and defined flexible capacity need: "Flexible capacity need" is defined as the quantity of economically dispatched resources needed by the California ISO to manage grid reliability during the greatest three-hour continuous ramp in each month. Resources will be considered as "flexible capacity" if they can sustain or increase output, or reduce ramping needs, during the hours of "flexible need." (D 13-06-024, page 2). The Decision adopted the following formula to calculate system flexibility requirement:

$$\boxed{\text{Flexibility Need}MTH_y = \text{Max}\,[(3RRHR_x)\ MTH_y] + \text{Max}(MSSC,\ 3.5\%*E(PLMTH_y)) + \varepsilon}$$

Where,

Max [(3RRHR$_x$) MTH$_y$] = Largest three hour continuous ramp starting in hour x for month y

E(PL) = Expected peak load

MTH$_y$= Month y

MSSC = Most Severe Single Contingency

ε = annually adjustable error term to account for uncertainties such as load following. This term is zero for 2015.

As per the FRAC-MOO proposal, the ISO proposed to allocate to the CPUC a flexible requirement, which consists of the aggregate of ISO- determined individual CPUC jurisdictional LSE flexible obligations. The ISO proposes to use causation principles to allocate flexible obligations to Local Regulatory Authorities ("LRAs") such as the CPUC. Specifically, "The ISO will allocate the proportion of the system flexible capacity requirement to each LRA based on its jurisdictional LSEs' contribution to the ISO's largest 3 hour net-load ramp change each month. The ISO will calculate each LSE's contribution to the net-load change using historic changes in load and forecasted changes in wind output and solar output, and distributed generation. The ISO intends to follow the CPUC allocation methodology when allocating flexible capacity resource adequacy backstop costs in the event of a shortfall in procurement or operation of flexible generation. Specifically, "If a LRA allocates the flexible capacity requirement to its jurisdictional LSEs using a different allocation methodology, then the ISO will use that LRA's allocation methodology when allocating backstop costs in the event that there is a flexible capacity shortfall by one or more of the LRAs load serving entities." (FRAC-MOO proposal, Section 5, page 17). For the 2015 RA year, we will use load- ratio share to allocate flexibility among LSEs. In the future, we intend to explore other methods of allocation based on causation through the RA proceeding, potentially in conjunction with staff's analysis of reliability needs. An LSE's flexible procurement obligation is calculated as follows, consistent with how system and local RA requirements are allocated.

LSE monthly flexible capacity procurement obligation = [(LSE monthly coincident peak load)/ (ISO monthly coincident peak load)]* Cumulative monthly flexible capacity requirement

Section III. Flexible capacity requirements study

By May 1 of each year (or as soon as practical), the ISO will complete and file in the RA proceeding, a flexible capacity requirements ("FCR") study together with the Local Capacity Requirements ("LCR") study, which lists flexible capacity needs for each month of the following year. Parties to the RA proceeding will vet the studies and submit comments to the CPUC. The annual RA decision will then adopt final study results, which consists of total monthly flexible obligations for CPUC LSEs along with the LCR. The timeline of this study process will mirror that of the current LCR schedule.

Section IV. What qualifies as flexible capacity?

In order to qualify as a flexible resource, the resource must meet the following criteria:

1. A resource must qualify as an RA resource and have a qualifying capacity ("QC") in order to have an EFC
2. A resource must be able to ramp and sustain energy output for a minimum of three hours

Section V. Counting conventions

Specific counting conventions apply to determine the Effective Flexible Capacity ("EFC") of resources relative to a resource's Net Qualifying Capacity ("NQC"). The EFC reflects the flexibility of a resource that can be counted towards an LSE's flexible RA obligations.

The proposed counting conventions for EFC applicable in 2015 are listed below:

Dispatchable thermal resources

- If start-up time of resource is greater than 90 minutes then EFC is limited to the MW range between Pmin and NQC as limited by ramp rate.
  <u>EFC= minimum of (NQC-Pmin) or (180 min * RRavg)</u>
  Where: RRavg = average between Pmin and NQC.
- If start-up time of resource is less than or equal to 90 minutes then EFC is limited to the MW range between zero and NQC as limited by start-up time and ramp rate.
  <u>EFC = minimum of (NQC) or (Pmin + (180 min – SUT) * RRavg)</u>
  Where: SUT = Longest (cold) RDT start-up time in minutes.
  Cold start-up time is the highest value in the startup time segments for the resource.
  RRavg = average between Pmin and NQC.

Hydro resources

A hydro resource will qualify as flexible if it has the physical storage capacity to provide energy for up to Pmax for six hours. A hydro resource will be permitted to designate an EFC value annually for each month of a counting year. The proposed EFC shall not exceed the NQC or the Pmax of the hydro resource.

Combined Heat and Power Facilities

A Combined Heat and Power ("CHP") resource will be permitted to designate an EFC value annually for each month of a counting year to reflect its unique operating requirements related to industrial host obligations or CHP contract limitations. EFC of a CHP resource is capped at the lesser of the NQC or Pmax minus Pmin.

Section VI. Effective flexible capacity list

The CPUC and ISO will develop and post a draft listing the effective flexible capacity amount for each participating dispatchable resource ("EFC list") which passes a threshold test. The test requires the resource to have placed at least one economic bid in the real-time market for ten or more days in the previous calendar year. If the resource passes this test, then its EFC is calculated using the relevant counting conventions.[1] Newly constructed resources are exempt from this test during the first calendar year of operation. Mirroring the current NQC list process, the ISO is expected to issue a draft EFC list in May. Generators may request modifications or additions to these lists and by sending these requests to the CPUC and ISO. Generators may refer to the CPUC for further details. The ISO and CPUC will issue the final EFC list for CPUC jurisdictional LSEs by September.

[1] FRAC-MOO proposal, Section 4, page 13.

Section VII. RA showings and validation

CPUC Staff will send each LSE its flexible capacity obligation along with the system and local RA requirements in July of 2014 for the 2015 compliance year. Demand response programs are not listed on the EFC list but will be allocated to the LSE by the Energy Division. LSEs must use NQC to satisfy system and local RA obligations. The EFC and NQC of a resource are distinct numbers, and may not be used interchangeably. Each LSE shall make a 1) year-ahead, and 2) month-ahead showing of flexible capacity for each month of the compliance year. In the showing an LSE must submit the committed flexible capacity it has contracted for the compliance period to meet its flexible RA obligation. The LSE is not required to commit additional flexible capacity beyond its flexible RA obligation. A committed flexible resource is a qualified flexible resource under contract to perform under the applicable flexible must-offer obligation. In order to verify the committed flexible capacity that is being shown in the RA filing, staff will compare LSE RA filings against the generator's corresponding supply plan filed with the ISO. Validation of each LSE's flexible capacity obligation supplements the validation of RA filings against local and system RA obligations. Year-ahead compliance filings should demonstrate that 90% of flexible capacity obligation is met for January to December. Month-ahead filings need to demonstrate that 100% of flexible capacity obligation is met for the month.

A megawatt of capacity counts only once – as flexible or generic. A resource may have flexible megawatts and generic megawatts based on its start-up time and how it was contracted to the LSE. Flexible megawatt and generic megawatt count towards system RA obligation. Only flexible megawatts count towards meeting flexible RA obligation. If the resource is in a local area, the combined total MW contracted from the facility count towards system and local RA requirements. For example, an LSE contracts with a resource with an NQC of 200 MW, a Pmin of 50 MW, and an EFC of 150 MW in a local area. The LSE can make the following RA showing if it contracts all the capacity within a resource including both flexible and generic.

System RA	Local RA	Flexible RA

200 MW	200 MW	150 MW

For RA showing purposes the EFC of a resource committed by an LSE may be greater than, equal to, or less than the NQC committed for that resource. The committed EFC will bear obligations under the flexible must-offer obligation as specified by the ISO tariff. The NQC of a resource will bear obligations under the resource adequacy must-off obligations as specified by the ISO tariffs for generic capacity. IOUS are expected to adhere to the principals of least cost best fit.

Section VIII. Sale and purchase of flexible capacity

The sale of flexible capacity will entail an enhanced must-offer obligation and a potentially higher cost to a resource owner due to potential increases in wear and tear on a facility due to cycling. Therefore, a resource owner will have discretion in the sale of generic and flexible capacity. A resource must submit economic bids into the ISO's day- ahead and real time markets for the committed flexible portion of the facility's operating range. A megawatt may be sold only once as either flexible or inflexible. A resource owner may sell the flexible and inflexible capacity in separate transactions and to different purchasers. A resource owner may elect to sell any portion of qualified flexible capacity as inflexible. A resource owner with a resource consisting of both "generic" capacity (below Pmin) and "flexible" capacity, may elect to, or not to, sell the generic capacity prior to selling the flexible portion capacity.

For example an LSE contracts with a resource with an NQC of 200 MW and a Pmin of 50 MW. The resource owner could:

1. Sell the entire 200 MW as generic capacity;
2. Sell or not sell up to 50 MW as generic and sell up to 150 MW as flexible. In either case, the scheduling coordinator would still have to bid or self-schedule the 50 MW of generic capacity;
3. Sell up to 200 MWs in any of the above combinations to different purchasers.

Flexible Capacity, local capacity and system capacity are distinct RA products that need to be distinguished in Request for Offers and bilateral contracts to purchase or sell

RA capacity for investor-owned utilities ("IOUs"). In order to avoid over procurement, an IOU must try to commit flexible resources towards meeting flexible, system and local RA requirements concurrently. We expect IOUs to employ prudent procurement and follow the rules of least cost best fit. However, an LSE's generic and flexible obligations will be examined separately. Each generic RA MW committed by an LSE in its RA showing as generic RA counts toward that LSE's generic RA obligation, and each flexible RA MW of a resource committed by an LSE in its RA showing as flexible RA counts toward its flexible RA obligation. We expect LSEs to employ procurement and showing practices that maximize efficiency and avoid any excess procurement.

Section IX. Penalties

The current penalties applicable to local RA deficiencies will apply to flexible RA deficiencies. D.11-06-022 modified the penalty structure of the RA program, changing both the penalties applicable under Resolution E-4195 as well as the other penalties of the program. D.11-06-022 eliminated the penalty for small procurement deficiencies, and instead created a Specified Violation for any procurement deficiency remedied within five business days. For those deficiencies not cured within five business days, the other penalties adopted in D.10-06-036 continue to apply. The penalty structure follows.

Energy Division proposed to apply system RA penalties for noncompliance of the flexible capacity procurement requirements. System RA penalties, at $6.66/kW-month, are twice those for local RA ($3.33/kW-month) and are applied when an LSE fails to procure to meet its requirements within the five-day cure period. As 2015 is the first year for a flexible capacity procurement obligation on LSEs and due to potential contracting complexities, the Proposed Decision was modified to adopt AReM's proposal to impose a lower RA penalty.

Table-1

	Deficiency in Flexible RA Filing (Modifying Appendix A in Resolution E-4195)
Deficiency cured within five business days from the date of notification by the Energy Division	$5,000 per incident if the deficiency is 10 MW or smaller, $10,000 for a deficiency larger than 10 MW. For the second and each subsequent deficiency in any calendar year, penalties will be $10,000 per incident if the deficiency is 10 MW or smaller, $20,000 for a deficiency larger than 10 MW.
Replaced after five-business days from the date of notification or not replaced	$3.33/kW-month

Section X. Use-limited flexible resources

D.13-06-024 directed staff and parties to develop rules regarding use-limited resources. Staff organized a workshop on October 15, 2013, which among other things included a discussion on use-limited resources.

Use-limited resources can be classified as resources that can run in all or most hours, but are limited in the total starts or hours they can run; or resources that cannot offer in certain hours (excluding outages). This includes but is not limited to, thermal units limited by starts or emissions, demand response, hydro resources, storage, and variable energy resources ("VERs"). Flexible use-limited resources must be operationally capable of ramping or sustaining output for three continuous hours.

Interim Approach

On January 28, 2013 the ISO issued the "Reliability Services Initiative." Specifically, among other things the ISO proposes that the scope of this initiative include: enhancing the minimum eligibility criteria for system, local, and flexible RA capacity where needed and modifying must-offer rules where required, in particular for use-limited resources, in order to standardize must-offer requirements for different technology types, as is feasible.[2] On February 5, the CPUC issued the "Order Instituting Rulemaking" which considers forward multi-year RA requirements, implementation of a planning assessment, and determining rules and Commission policy position with respect to the ISO's market-based backstop procurement mechanism. Both of these initiatives will have a significant impact on flexible RA procurement. Therefore, we will institute an interim approach through December 31, 2017.

As an interim approach, we require LSEs to procure flexible resources in accordance with flexible categories based on varying must-offer obligations and energy limitations. We adopt a three- category approach with fixed monthly percentage limits. We believe this approach is simple and creates provisions for preferred resources to participate in the flexible capacity procurement framework.

The LSEs shall procure and show their flexible resources according to the characteristics defined in Table-1.

[2] CAISO Reliability Service Issue Paper (January 28,2014).

Table -2 Categories of must-offer

	Category 1	Category 2	Category 3
Must-offer obligation	17 Hours	5 Hours	5 Hours
	5 AM- 10 PM Daily For the whole year	7 AM – 12 PM for May – September	7 AM – 12 PM for May – September
	5 AM- 10 PM Daily For the whole year	3 PM- 8 PM for January- April and October-December	3 PM- 8 PM for January- April and October-
	Daily	Daily	Non-holiday weekdays
Energy limitation	At least 6 Hours	At least 3 Hours	At least 3 Hours
Starts	The minimum of two starts per day or the number of starts allowed by operational limits as determined by minimum up and down time	At least one start per day	Minimum 5 starts a month
Percentage of LSE portfolio of flexible resources	At least 68 % for May – September	Up to 32% for categories 2 and 3 combined	Up to 5%
	At least 74 % for January- April and October-December	Up to 26% for categories 2 and 3 combined	Up to 5%

We observed that almost all of the flexible resources reported by LSEs were in category 1. If the ISO observes a collective deficiency in these categories, it might backstop to meet the requirements. In case of such a shortfall, the CPUC will allocate the backstop costs to LSEs based on their respective load ratio shares. The categories will be assessed annually and the percentages for flexible categories may change accordingly.

The ISO is expected to issue monthly advisory targets to the CPUC for flexible categories in the FCR study (See Section 3). Staff will design the annual RA compliance template to implement the monthly category limits and issue the template to LSEs along with the overall RA obligations, in July of each year. Staff will validate the RA showings to ensure that the flexible categories are met and issue deficiency notices where essential.

Long term approach

While we allow the participation of use-limited resources through the creation of categories in the interim period; we also acknowledge that we must develop a long term framework to further enable the participation of all qualifying resources. Further, the Commission will design a long-term approach with an eye toward enabling greater consistency with the State's loading order for preferred resources to meet flexible capacity requirements, based on learning following implementation of this proposal, which may include a revision of percentage or timing limitations on all flexible categories.[3]

The LSE should indicate which of its resources in the committed flexible RA portfolio are use-limited.

Section XI. Next steps for 2016 RA year

1. Explore a flexible capacity allocation methodology that reflects causation.
2. RA compliance is complex and includes multiple degrees of scrutiny regarding requirements for system RA, local RA, and flexible RA, monthly CAM allocations, import allocations, Path-26 restrictions, regular true ups, load migration adjustments, flexible categories etc. Comprehensively reform the RA procurement framework and adopt rules that simplify the compliance process.
3. Further assess if the three flexible categories address the objective of managing use- limited resources and allowing the participation of preferred resources and the appropriateness of characteristics for each category. For example, category 3 resources only need to provide flexibility during the weekdays. We might evaluate

[3] In the case of demand response resources, the Commission will design future programs to meet CAISO and CPUC RA criteria, for flexible, system and local, as they exist in this proposal and as these criteria are modified in the future.

current DR programs and recommend changing the weekday requirement to a daily requirement.

4. Explore the possibility of exempting flexible resources from satisfying system RA requirements. System RA is geared towards meeting peak load while flexible meets non-peak requirements. We will assess the overall impact on contracting, procurement, and must-offer obligations before recommending this policy.

Section XII. Timetable and functions for flexible RA

Date	ISO function	CPUC function
March	ISO issues draft FCR and LCR	
May 1	ISO submits FCR study (with LCR) to CPUC. CPUC parties may vet these studies and submit comments to RA proceeding.	
May	Draft EFC List (with NQC list)	Calculate draft EFC (with NQC) lists and post to CPUC website
End of May		Annual RA Proposed Decision for compliance year adopting local capacity and flexible capacity requirements
End of June		Annual RA Decision for compliance year adopting local capacity and flexible capacity requirements
July		CPUC staff sends out flexible capacity obligations for LSEs along with local and system RA obligations
September 1	Final EFC List (with NQC list)	Final EFC List (with NQC list)
September		CPUC staff sends out revised flexible obligations (with system and local obligations) to account for load revised forecasts
End of October	Year-ahead LSE RA filings showing 90% of flexible obligations due	Year-ahead LSE RA filings showing 90% of flexible obligations due
Each Month T-45	Month-ahead LSE RA filings showing 100% of flexible obligations due	Month-ahead LSE RA filings showing 100% of flexible obligations due
T-25	LSE may receive **discrepancy notice** in case of shortfall (informational only)	LSE may receive **deficiency notice** in case of shortfall. LSEs have five business days to cure the deficiency.

(END OF APPENDIX A)

APPENDIX B

Appendix B: Qualifying Capacity and Effective Flexible Capacity Calculation Methodologies for Energy Storage and Supply-Side Demand Response Resources

10. Introduction

This Appendix details the methodologies for the California Public Utilities Commission (CPUC) determination of Qualifying Capacity (QC) and Effective Flexible Capacity (EFC) for energy storage and supply-side demand response (DR) resources. A resource's QC is the number of megawatts eligible to be counted towards meeting a load serving entity's (LSE's) System and Local Resource Adequacy (RA) requirements, subject to deliverability constraints.[1] A resource's EFC is the number of megawatts eligible to be counted towards meeting an LSE's Flexible RA requirements.

The only storage and DR resources that are included in the scope of this Decision are those that bid or self-schedule into California Independent System Operator (CAISO) markets and are subject to a Must-Offer Obligation (MOO). These resources are: transmission-level energy storage, some distribution-level and behind-the-meter storage (depending on whether it is operated in accordance with the above requirements), and supply-side demand response.[2]

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[1] The revised QC that incorporates deliverability constraints is called the Net Qualifying Capacity (NQC).

[2] Information on the energy storage and demand response proceedings, including additional details on what types of resources are considered to be energy storage and supply-side demand response, can be found at http://www.cpuc.ca.gov/PUC/energy/electric/storage.htm and http://www.cpuc.ca.gov/PUC/energy/Demand+Response/DemandResponseWorkshops.htm, respectively.

Supply-side demand response is distinguished here from customer-focused programs and rates, and from existing "Retail DR" utility programs. On March 27, 2014, the Commission adopted D.14-03-026, which adopted the bifurcation framework for DR programs. In the next phase of the DR Rulemaking, R.13-09-011, the Commission will begin the process of defining programs as Supply Resources and Load-Modifying Resources. As this process develops, we will coordinate across both that rulemaking and the RA rulemaking to ensure consistency. Customer-focused programs and rates (and existing Retail DR programs) will continue to receive RA credit in the 2015 RA compliance year as they have in past years, according to existing rules; they are not addressed in this document.

11. RA Eligibility Requirements for Energy Storage and Supply-Side DR

11.1. Operational Requirements

To the extent possible, System, Local, and Flexible RA eligibility requirements should remain consistent across all resource types, including storage and supply-side DR. These requirements include the ability to operate for at least four consecutive hours at maximum power output ($Pmax_{RA}$), and to do so over three consecutive days.

Resources wishing to qualify for System or Local RA must also have the capability to offer into the CAISO markets, either via economic bids or via self-scheduling, under the Must Offer Obligation (MOO) applicable for that resource type.

Resources that wish to be qualified as Flexible RA must comply with the bidding and availability requirements expressed in the CAISO's Flexible RA

Criteria and Must Offer Obligations (FRAC-MOO).[3] However, storage and DR resource operators that wish to receive Flexible RA credit for charging capacity need not meet the storage-specific requirements of FRAC-MOO. Specifically, no resource is required by the CPUC to register as a non-generating resource (NGR) in order for charging capability to contribute towards that resource's Commission-adopted EFC.

Co-located storage operating in conjunction with (i.e., not independently dispatchable from) another, larger RA-eligible resource need not meet the RA eligibility requirement of being able to operate for four consecutive hours on three consecutive days; the RA qualification of the primary generating facility is sufficient.

Future modeling of reliability may indicate ways in which some of the above requirements could be altered; future RA proceedings will be informed by that analysis.

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[3] A must-offer obligation, or MOO, is a commitment to be available for dispatch by the CAISO. The MOO is distinct from the four hour capability requirement for continuous operation upon dispatch. System and Local RA resources, whether DR or storage, may either bid into the CAISO markets or self-schedule. The proposed MOO for Flexible RA resources (FRAC-MOO) aims to ensure that flexible resources will be available to contribute to the times of greatest system ramping. The proposed FRAC-MOO requirements can be found at https://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx and http://www.caiso.com/Documents/Board%20of%20Governors%20meetings/Board%20of%20Governors%20meetings%20-%202014/Board%20of%20Governors%20meeting%20Mar%2019-20,%202014/Board%205)%20Decision%20on%20flexible%20resource%20adequacy%20criteria%20and%20must%20offer%20obligation.

11.2. Resource Aggregation

Energy storage resources located within a single sub-load aggregation point (Sub-LAP) may be aggregated to form a single, RA-eligible storage resource. DR resources located within a single Sub-LAP may be aggregated to form a single, RA-eligible DR resource. Storage and DR may not be jointly aggregated to create a combined Storage-DR resource at this time, but we may explore this possibility in future RA compliance years.

Elements of aggregated resources need not individually meet RA eligibility requirements; rather, the resource as a whole must demonstrate eligibility. For example, a demand response provider may aggregate one resource that provides up to 1 MW for up to two hours and is available between the hours of 1 and 4 pm with another resource that is able to provide up to 1 MW for up to two hours and is available between the hours of 3 and 6 pm, in order to create an aggregated resource that is able to provide up to 1 MW for up to four hours and is available between the hours of 1 and 6 pm. An additional example of resource aggregation is shown in Figure 1, below.

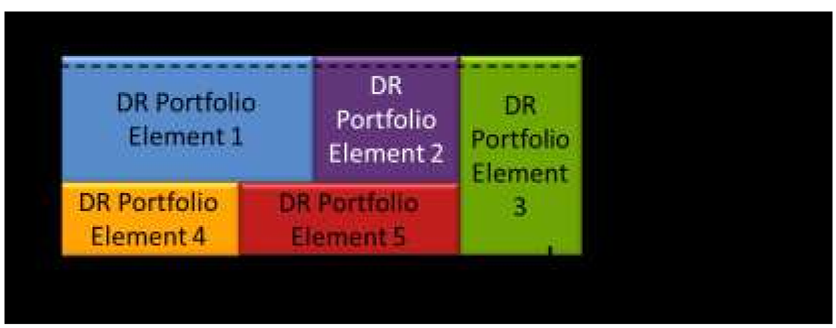

Figure 1. Supply-side demand response resource aggregation example

12. CPUC Testing and Verification Requirements

QC and EFC determinations shall incorporate historical performance data where possible. To the extent that historical performance data is not available or appropriate, program design and/or test data may be used. Resource operators may elect to request a QC or EFC that is lower than that calculated by Energy Division, if they wish to reduce the amount of capacity that is subject to a MOO. For example, operators may request to qualify an aggregate resource for an RA capacity that is less than its theoretical maximum output, as illustrated in Figure 1 above, in order to account for anticipated non-performance in some portion of the portfolio. This would allow operators to account for some storage not being in the desired state when dispatched, or to account for a portion of DR participants overriding dispatches.

In adopting the rules that follow for the 2015 RA compliance year, the Commission looks forward to further refinement of testing and performance reporting protocols in future years, as it seeks to balance the needs for verifiable performance, practical feasibility, and reasonable cost. Additionally, the Commission may consider testing and assessment protocols that can measure the performance of storage and supply-side demand response resources as part of the storage and demand response proceedings.

12.1. Demand Response Testing and Verification Requirements

12.1.1. Testing Requirements

DR must be tested and/or dispatched at least once per calendar year, to demonstrate initial and continued performance. Supply-side DR test results must be provided to the Commission by the LSE showing a given resource. Testing should simulate expected dispatch conditions, including adherence to the notification period specified in the applicable CAISO tariff, and two-hour testing is required to ensure performance does not degrade over the course of operation. Resources offering both curtailment (reducing customer consumption) and dispatchable load (increasing customer consumption) must demonstrate both operational modes in testing. These two modes may be demonstrated in either one single test event or in two separate test events, as required to comply with CAISO testing requirements and any DR evaluation rules that are promulgated by the Commission in the future.

Operators should be paid for the test event in accordance with the applicable CAISO tariff. This testing will be designed in coordination with the CAISO, to avoid duplicative testing. The testing must only be repeated if the DR program is not dispatched for two or more consecutive hours at any time over a given calendar year. If the DR is dispatched for at least two consecutive hours on at least one day during a given calendar year, additional testing is not required for that calendar year.

DR wishing to qualify as Flexible RA must submit to testing that occurs within the applicable must-offer obligation window; this time window will depend on the Flexible RA category for which the resource wishes to qualify, as described in the recently-approved CAISO FRAC-MOO proposal. The DRP must receive advance notification as specified in the applicable tariff. For example, a resource with a tariff that requires four hours of advance notice must still receive at least four hours' notice of the test dispatch in order for the test to be accepted by the Commission.

If there is an applicable CAISO test for a given DR resource qualifying as Flexible, System, or Local RA, then that test data is required to be submitted by the LSE showing the resource in its RA compliance filing, and is sufficient to meet Commission testing requirements. For example, the testing proposed in the

CAISO FRAC-MOO initiative would apply to DR resources wishing to qualify as Flexible RA, if adopted by FERC. If there is not an applicable CAISO test, then the LSE must test performance in accordance with the following requirements, and submit the results to the Commission along with its RA compliance filings:

- For Flexible RA resources, testing must comply with the requirements discussed above, such as two-hour testing. It must occur within a three-month period chosen by the demand response provider, with the date and time randomly selected by the LSE (within the date and time constraints of the DR resource, as described in its tariff).
- System and Local RA resources must submit to similar testing; however, this testing may be conducted at a time of the operator's own choosing, rather than at a time selected by the CAISO. The timing shall nevertheless be constrained to the standard availability assessment hours that apply to System and Local RA resources.

Successful testing to qualify as Flexible RA will be deemed sufficient for qualification as System and Local RA, provided that the program design complies with those product types. Namely, the program must be available during at least four of the standard availability assessment hours each day to qualify as System RA, and the program must also be locally dispatchable to qualify as Local RA.

Regardless of the testing methodology, test performance will be assessed according to the Load Impact Protocols, as described below.

12.1.2. Performance Assessment

DR performance will be measured based on ex-ante load impact estimates using the load impact protocols, as is already the case for the utilities' current DR programs (Retail DR).[4] As is already the case for Retail DR, QC calculations must be based on 1-in-2 weather conditions. These ex-ante estimates must be submitted to the Commission by DR providers and must take into account ex-post (after-the-fact) results from testing and dispatches.

In determining the resource's QC and EFC, ex-ante results may be further adjusted by the CPUC to reflect anticipated changes in weather, enrollment, or program design. Resource operators may request such adjustments if they submit documentation of anticipated changes to ED (such as new enrollment data or program design changes). If ED chooses to adjust test results (whether upwards or downwards), an explanation of the adjustments made will be made publicly available.

12.2. Energy Storage Testing and Verification Requirements

Energy storage must be tested in the same manner as fossil generators, and the results must also be submitted to the CAISO in the same manner as for fossil generators. However, storage resources must demonstrate not only maximum and minimum rated discharge levels (in MW), but also maximum and minimum rated charging levels (in MW).[5] Resource operators must also submit additional relevant resource characteristics to the CAISO for inclusion in its MasterFile, as listed and described in the *Nomenclature* section below.

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[4] The load impact protocols were specified by Decision 08-04-050, and modified by Decision 10-04-006.

[5] For further clarification on the various charge/discharge levels, see the *Nomenclature* section below.

12.3. Reporting for Aggregated Resources

In accordance with applicable CAISO tariffs, aggregated resources may provide performance data from a single aggregation point and need not report individual element performance in real time or on a regular basis. Regardless of aggregation, individual element performance data must be made available to the CPUC and the CAISO for auditing and verification purposes upon request and as part of initial testing for RA qualification.

13. Approach Recommended for QC and EFC Calculations for the 2015 RA Compliance Year

13.1. Qualifying Capacity (QC)

Dispatchable storage shall receive a QC in the same manner as other dispatchable resources, including testing and verification in CAISO operations. Because all RA resources must be able to operate for four or more consecutive hours, the storage operator must submit to the CAISO an output level (in MW) at which the resource is capable of discharging for four or more uninterrupted hours; this is defined to be its $Pmax_{RA}$, the maximum output that can be considered for RA calculations. Like fossil generators, the storage facility must then submit to physical testing by the CAISO to verify that it can be dispatched at this capacity. The QC will be equal to this $Pmax_{RA}$ value. The facility is also subject to the standard CAISO NQC process, whereby the Net Qualifying Capacity of a resource is limited to an output level that is deliverable to the aggregate of CAISO load; this process is also undertaken for conventional resources.

Storage facilities may also submit a short-term maximum rated output to the CAISO, for dispatch purposes. This is defined as the resource's Pmax, and is a value which could be greater than $Pmax_{RA}$. If the Pmax output duration is below the four hour requirement for RA eligibility, it cannot be used as the $Pmax_{RA}$ value in RA credit determinations.

DR resources shall receive QC values based on the load impact protocols, in the same manner as existing Retail DR. Adjustments may be made by Energy Division staff as described in the Demand Response Testing and Verification Requirements section.

13.2. Effective Flexible Capacity (EFC)

13.2.1. EFC Framework

Storage and DR resources shall receive an EFC in accordance with the bundling principle, which holds that all Flexible RA resources must also qualify as System RA resources. In other words, storage and DR facilities wishing to qualify for Flexible RA must also be qualified for System RA, and must receive QC values as described previously. Additionally, $Pmax_{RA}$ values for Flexible RA shall be identical to those utilized in determining the resource's System RA credit, and set according to the rules previously described.

EFC shall incorporate dispatchable load and charging (for DR and storage, respectively) because these operational modes can address ramping needs. Qualifying capacity, because it solely aims to address capacity shortfalls, will not incorporate these operational modes. This difference will frequently result in EFC being greater than QC. While EFC has previously been limited to be less than or equal to NQC, we hereby modify that rule and instead EFC to the greater of NQC and (NQC – $Pmin_{RA}$), where $Pmin_{RA}$ is the minimum sustainable operating level of a facility, as defined in more detail below. If a facility is capable of dispatchable charging (in the case of storage) or load increase (in the case of DR), its $Pmin_{RA}$ will be negative.

All facilities are subject to CAISO testing to verify the submitted $Pmin_{RA}$, as previously described in the *CPUC Testing and Verification Requirements* section. In the future, negative $Pmin_{RA}$ may also be subject to limits on how much charging is possible given transmission or other physical constraints, if the CAISO develops deliverability or other physically-based assessments for that condition.

All EFC values will be based on the currently-adopted definition of flexibility: the ability to ramp and sustain output over three hours.[6] Because storage and demand response resources can have positive generation (discharge or load curtailment), negative generation (dispatchable charging or load increase), or both positive and negative operating ranges, and because certain resources are better suited to either ramping or sustaining output, multiple methodologies are needed to address the multiple operational modes permissible for flexible resources under this definition.

13.2.2. Nomenclature

Conventional generators in the RA program are described by two key points of possible dispatch: Pmax, the maximum sustainable output, and Pmin, the minimum sustainable output. Storage and demand response resources, on the other hand, are characterized by up to four points of operational dispatch (all in MW):

1. $Pmax_{RA}$ – the maximum output sustainable for four hours (as described in the QC section above); may be less than the maximum rated discharge/curtailment level.

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[6] D.13-06-024, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M070/K423/70423172.PDF.

2. $Psupply_{min}$ – a positive number representing the minimum amount of discharging or load curtailment that is sustainable for three or more consecutive hours (for example, the minimum amount of DR that may be dispatched); does not apply to resources with only negative operating ranges, and may be zero for resources that do not have physically or programmatically-constrained minimum output levels.
3. $Pdemand_{min}$ – a negative number representing the smallest magnitude of charging or load increase that is sustainable for the duration required in calculating EFC (for example, minimum pump loads); does not apply to resources with only positive (discharging or load curtailment) operating ranges, and may be zero for resources that do not have physically or programmatically-constrained minimum charging/load increase levels.
4. $Pmin_{RA}$ – either equal to $Psupply_{min}$ for resources with only positive operating ranges (those that can only discharge), or a negative number representing the largest magnitude of charging or load increase eligible for consideration in calculating EFC, as described further below; if negative, may be smaller in magnitude (closer to zero) than the maximum rated charge or load increase level.

Additionally, we introduce the term "bi-directional" to refer to resources with both negative (dispatchable charging or load increase) and positive (dispatchable discharging or load curtailment) operational capabilities.

This nomenclature is illustrated for various resource types in Figure 2, below.

Figure 2 shows all possible key points of possible dispatch for RA calculations; however, depending on resource capabilities, some resources will have a Pmax, Pdemandmin, Psupplymin, PminRA, or Pmin of zero, as described above.

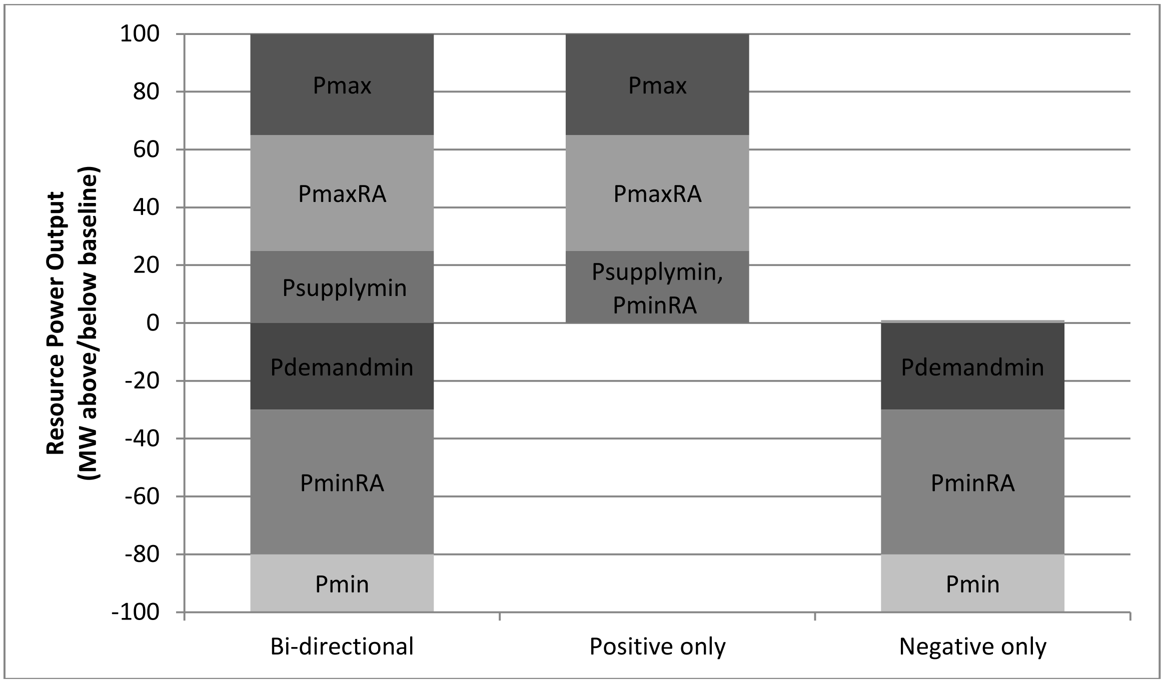

Figure 2. Key Operating Points for Bi-directional, Positive, and Negative Generation Resources

Storage and demand response resources are also described by several other operating characteristics:

- Ramp Rate – the maximum MW/minute by which a facility can increase its power output over a particular output interval (for example, from 20 to 50 MW). An increase in output is defined as a change in output that is in the direction from $Pmin_{RA}$ to $Pmax_{RA}$ (i.e., more positive generation or more load reduction); for DR, for example, increased output means an increase in the magnitude of load that is reduced. The ramp rate may change over different segments of operation; for example, a facility's ramp rate may be lower between 10 and 20 MW than it is between 20 and 50 MW.

- ARR (MW weighted average ramp rate) – the MW encompassed by a given operating range, divided by the amount of time it takes the facility to increase its output from the bottom to the top of the range. For resources with a negative operating range, ARR_{neg} covers the range from $Pmin_{RA}$ to $Pdemand_{min}$. For resources with a positive operating range, ARR_{pos} covers the range from $Psupply_{min}$ to $Pmax_{RA}$.

- Round Trip Efficiency (only applies to storage with both charging and discharging capabilities) – the efficiency with which a storage resource takes charge and converts it to discharge. This value is a percentage that represents the portion of the charge that can be discharged, considering losses. This value is equivalent to the ENERGY_EFFIC variable in the CAISO MasterFile.
- Available Energy – the total MWh of energy available to be discharged from a storage device (or to be dispatched from a single call of a DR resource). This is equivalent to the MAX_CONT_ENERGY_LIMIT variable in the CAISO MasterFile.
- Transition Time – the time it takes for a storage or demand response facility to switch from positive generation (discharge or load curtailment) to negative generation (charging or load increase), or vice versa. This variable is equivalent to the MIN_DWN_TM_PG and MIN_DWN_TM_GP variables in the CAISO MasterFile.
- Shut-down Time – the time it takes for a resource to fully shut down, or to cease charging/discharging (or to cease increasing/decreasing load relative to baseline). For pumped storage facilities, this variable is equivalent to the PUMP_SHTDWN_TM variable in the CAISO MasterFile.

13.2.3. $Pmin_{RA}$ Methodology Examples

13.2.3.1. Case 1: Storage or DR with only positive output ranges (discharge/curtailment only)

Storage and DR resources with *only positive output ranges* have a $Pmin_{RA}$ equal to the minimum operating level (in MW) sustainable for three or more consecutive hours (equivalent to $Psupply_{min}$). $Pmin_{RA}$ may be zero, if the resource does not have a non-zero minimum output constraint. For example, consider a DR resource that can curtail only, and can curtail anywhere between 1 and 2 MW when dispatched. If the resource can curtail at its minimum level

(1 MW) over three or more hours, then that 1 MW is its $Pmin_{RA}$. This example is illustrated in Figure 3, below.

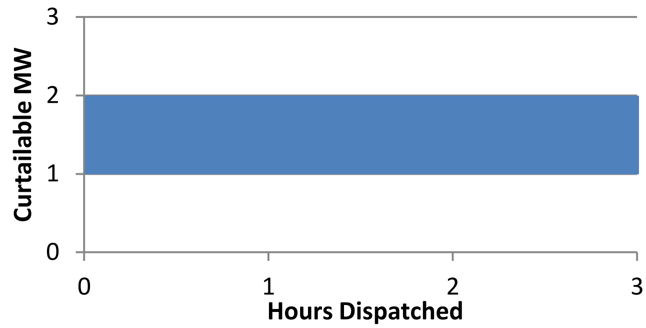

Figure 3. An example DR resource with $Pmin_{RA} = Psupply_{min} = 1$ MW

13.2.3.2. Case 2: Storage or DR with only negative output ranges (dispatchable charge/load increase only)

Facilities with a *negative operating range only* (i.e., a $Pmax_{RA}$ of zero) must submit a $Pmin_{RA}$ value that is either sustainable for the full three hours required for Flexible RA eligibility, or that can serve as a starting point for upward ramping (generation becoming less negative) at a constant rate over the course of the three hours required for Flexible RA eligibility. They must also submit $Pdemand_{min}$, which represents the smallest magnitude of charging or load increase that is dispatchable (such as minimum pumping loads or the minimum increment of load increase that can be dispatched).

For example, if a 12 MWh storage resource is capable of dispatchable charging but not of dispatchable discharging, then its $Pmin_{RA}$ would be −12 MWh ÷ 3 hrs = −4 MW (unless the resource is further limited by its maximum rated charging capability), if the operator chooses the sustainable operation option.[7] The minus sign in this example indicates charging mode. This example is illustrated in Figure 4, below.

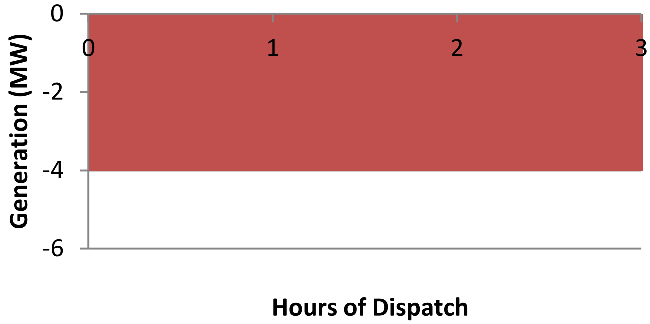

Figure 4. An example 12 MWh resource with dispatchable charging, no dispatchable discharging, and $Pmin_{RA}$ = -4 MW

Alternatively, if the operator chooses the upward ramping option, $Pmin_{RA}$ will be based on the ability to ramp upwards from $Pmin_{RA}$ to $Pdemand_{min}$ over three hours. If the resource has a $Pdemand_{min}$ of zero (meaning that it can ramp continuously to 0 MW), the resource will have a $Pmin_{RA}$ of −8 MW. This is because the −12 MWh of available charging energy is equal to the area of the triangle with height of −8 MW and base of 3 hours: 0.5 * −8 MW * 3 hrs = −12 MWh). This example is illustrated in Figure 5, below.

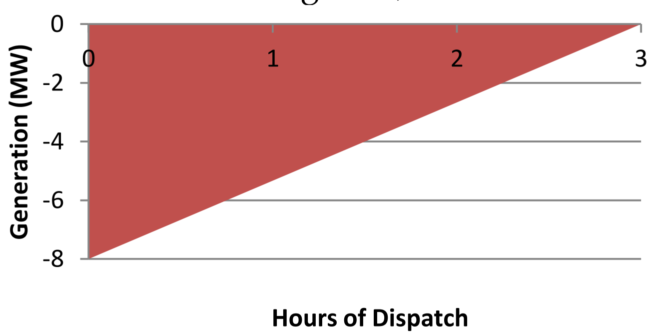

Figure 5. An example 12 MWh resource with dispatchable charging, no dispatchable discharging, and $Pmin_{RA}$ = -8 MW

If the resource is unable to ramp all the way to 0 MW (for example, due to pumps that have minimum energy requirements for operation), then $Pdemand_{min}$ is equal to the smallest possible magnitude of charging or load

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[7] Storage resources are typically rated based on the total discharge volume, not their charge capabilities; assuming that convention, this example neglects round-trip efficiency and depth of charge considerations. More precisely, the resource needs to be capable of accepting 12 MWh in charging energy (and have a maximum rated charging capability of at least 4 MW) in order for it to have a $Pmin_{RA}$ of −4 MW.

increase. For example, if the resource with −12 MWh of available charging energy has a $Pdemand_{min}$ of −1 MW, then the resource will have a $Pmin_{RA}$ of −7 MW (−1 MW from $Pdemand_{min}$ and −6 MW from ramping): −1 MW * 3 hrs + 0.5 * −6 MW * 3 hrs = −12 MWh. This example is illustrated in Figure 6, below.

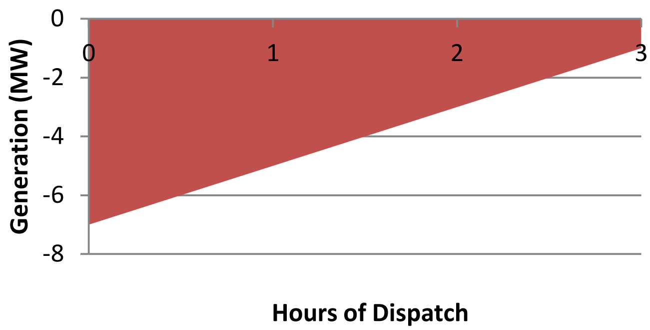

Figure 6. An example 12 MWh resource with dispatchable charging, no dispatchable discharging, and $Pmin_{RA}$ = -7 MW

More generally, the $Pmin_{RA}$ for a resource with only negative operating range that chooses the upward ramping option can be expressed as the lowest magnitude of either (1) the maximum rated charging or load-increase capability in MW, or (2) the largest magnitude of charge or load increase in MW from which the resource can ramp continuously for three hours, as shown in the equation below:

$$\mathrm{Pmin_{RA}[MW]} = \frac{2}{3\ \mathrm{hrs}} * (\mathrm{Maximum\ Available\ Energy\ [MWh]} - \mathrm{Pdemand_{min}[MW]} * 3\ \mathrm{hrs}) + \mathrm{Pdemand_{min}[MW]}$$

The equation above (which reflects the geometric calculations shown in the previous examples) can be algebraically simplified to:

$$\mathrm{Pmin_{RA}[MW]} = 2 * \frac{\mathrm{Maximum\ Available\ Energy\ [MWh]}}{3\ \mathrm{hours}} - \mathrm{Pdemand_{min}[MW]}$$

where $Pdemand_{min} \leq 0$ and is sustainable for at least 3 hours, and Maximum Available Energy < 0.

13.2.3.3. Case 3: Bi-directional storage or DR (with both positive and negative output ranges)

Facilities with *both positive and negative operating ranges* (i.e., *bi-directional resources*) must submit to the CAISO a $Pmin_{RA}$ (in MW) at which the facility is capable of charging (or increasing demand) for 1.5 or more uninterrupted hours, where $Pmin_{RA}$ is either sustained at a constant level or serves as a starting point for continuous upward ramping at a constant rate. Such facilities can thus meet the three-hour ramping requirement for flexibility by charging (or increasing demand) for the first half of the three-hour ramp and then discharging at or above $Pmax_{RA}$ for the remainder of the ramp.

For example, if a 12 MWh storage resource with 100% roundtrip efficiency is capable of dispatchable charging and of dispatchable discharging and chooses the sustainable output option, then its $Pmin_{RA}$ would be −12 MWh ÷ 1.5 hrs = −8 MW (unless the resource is further limited by its maximum rated charging capability), if the operator chooses the sustainable operation option. The minus sign in this example indicates charging mode. Its $Pmax_{RA}$ would remain equal to its 4-hour dispatch capacity, as calculated for its System RA QC value. In this case, $Pmax_{RA}$ = 12 MWh ÷ 4 hrs = 3 MW. Because of the bundling concept, whereby all Flexible RA must also be qualified as System RA, this value remains in effect despite the fact that for flexibility, only 1.5 hours of discharge are expected. This example is illustrated in Figure 7, below.

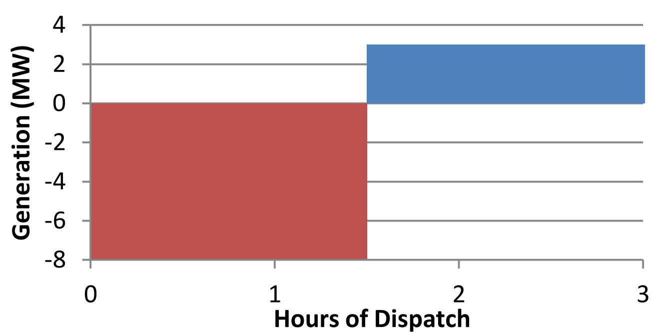

Figure 7. An example 12 MWh resource with dispatchable charging and discharging, $Pmin_{RA}$ = -8 MW, and $Pmax_{RA}$ =3 MW

Alternatively, if the operator chooses the upward ramping option, $Pmin_{RA}$ will be based on the ability to ramp upwards from $Pmin_{RA}$ to $Pdemand_{min}$ over 1.5 hours. If the resource has a $Pdemand_{min}$ of zero (meaning that it can ramp continuously to 0 MW), then a 12 MWh resource with 100% roundtrip efficiency will have a $Pmin_{RA}$ of −16 MW. This is because the −12 MWh of available charging (or load increase) energy is equal to the area of the triangle with height of −16 MW and base of 1.5 hours: 0.5 * −16 MW * 1.5 hrs = −12 MWh). This example is illustrated in Figure 8, below.

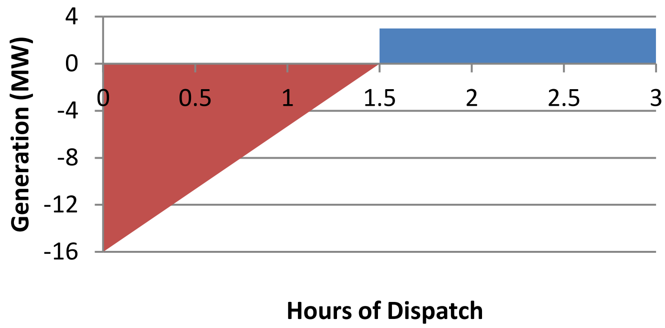

Figure 8. An example 12 MWh resource with dispatchable charging and discharging, $Pmin_{RA}$ = -16 MW, and $Pmax_{RA}$ =3 MW

If the resource is unable to ramp all the way to 0 MW (for example, due to pumps that have minimum energy requirements for operation), then $Pdemand_{min}$ is equal to the smallest possible magnitude of charging or load increase (and $Psupply_{min}$ is similarly equal to the smallest magnitude of dispatchable discharging or load curtailment). For example, if the resource with −12 MWh of available charging energy has a $Pdemand_{min}$ of −2 MW, then the resource will have a $Pmin_{RA}$ of −14 MW (−2 MW from $Pdemand_{min}$ and −12 MW from ramping): −2 MW * 1.5 hrs + 0.5 * −12 MW * 1.5 hrs = −12 MWh. This example is illustrated in Figure 9, below.

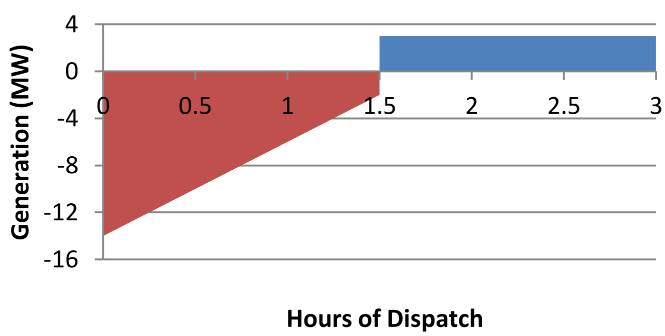

Figure 9. An example 12 MWh resource with dispatchable charging and discharging, $Pmin_{RA}$ = -14 MW, and $Pmax_{RA}$ =3 MW

More generally, the $Pmin_{RA}$ for a bi-directional resource that chooses the upward ramping option can be expressed as the lowest magnitude of either

(1) the maximum rated charging or load-increase capability in MW, or (2) the largest magnitude of charge or load increase in MW from which the resource can ramp continuously for 1.5 hours, as shown in the equation below:

$$\mathrm{Pmin_{RA}[MW]} = \frac{2}{1.5\ \mathrm{hr}} * (\text{Maximum Available Charge or Load Increase Energy [MWh]} - \mathrm{Pdemand_{min}[MW]} * 1.5\ \mathrm{hr}) + \mathrm{Pdemand_{min}[MW]}$$

The equation above (which reflects the geometric calculations shown in the previous examples) can be algebraically simplified to:

$$\mathrm{Pmin_{RA}[MW]} = 2 * \frac{\text{Maximum Available Charge or Load Increase Energy [MWh]}}{1.5\ \text{hours}} - \mathrm{Pdemand_{min}[MW]}$$

where $\mathrm{Pdemand_{min}} \leq 0$ and is sustainable for at least 1.5 hours, and Maximum Available Charge or Load Increase Energy < 0.

A non-zero transition time to go from $\mathrm{Pdemand_{min}}$ (minimum dispatchable magnitude of charge or demand increase) to $\mathrm{Psupply_{min}}$ (minimum dispatchable discharge or load curtailment) is not permitted at this time. Resources that require time to transition from negative to positive generation do not qualify as bi-directional Flexible RA resources. However, they may nevertheless qualify as positive-only or negative-only Flexible RA resources, assuming that they meet all relevant eligibility requirements.

Additionally, bi-directional resources are expected to be relatively symmetric. To avoid major deviation from charging symmetry, maximum available energy for charging or demand increase may not exceed the maximum available energy for discharge or load curtailment by more than a factor of two. For example, a resource with a $\mathrm{Pmax_{RA}}$ of 3 MW that can operate for four consecutive hours has a maximum available energy for discharge/curtailment of 3 MW * 4 hrs = 12 MWh. That resource is then permitted to have a maximum available energy for charging or load increase of up to –12MWh*2 = –24 MWh.

13.2.4. Ramp Rates

A ramp rate is defined as the maximum MW/minute by which a facility can increase its power output over a given operating range. The ramp rate may change over different segments of operation; for example, a 50 MW facility's ramp rate may be lower between 10 and 20 MW than it is between 20 and 50 MW. A facility's MW weighted average ramp rate is calculated based on these submitted ramp rates and is used to calculate its EFC.

Facilities with both positive and negative operating ranges will have two average ramp rates, one for each operating mode. For negative operation, ramping from $Pmin_{RA}$ to $Pdemand_{min}$ is included. For positive operation, ramping from $Psupply_{min}$ to $Pmax_{RA}$ is included. In both cases, the average ramp rate is defined as the MW encompassed by the applicable range, divided by the amount of time it takes the facility to increase its output from the bottom to the top of the range. For example, if a facility can go from $Pmin_{RA}$ = – 6 MW to $Pdemand_{min}$ = – 1 MW over the course of five minutes, then its average ramp rate in the negative operating range, ARR_{neg}, is (–1 MW + 6 MW) ÷ 5 minutes = 1 MW/minute. If the same resource can ramp from $Psupply_{min}$ = 0 MW to $Pmax_{RA}$ = 5.5 MW over the course of one minute, then its average ramp rate in the positive operating range, ARR_{pos}, is (5.5 MW – 0 MW) ÷ 1 minute = 5.5 MW/minute.

13.2.5. EFC Formula

Both storage and DR EFC calculations are based on the conventional EFC formulas, with modifications to allow for negative $Pmin_{RA}$ (indicating dispatchable load or charging) and for differences in ramping rates in the two operational modes. Generally speaking, the EFC represents the output that can be sustained or ramped over three hours. In the formulas that follow, average ramp rate is written as ARR_{pos} for the positive generation range and ARR_{neg} for the negative generation range. The start-up time is the number of minutes it takes the resource to go from being turned off (cold start) to generating at $Pmin_{RA}$. The shut-down time is the number of minutes it takes the resource to go from being at its minimum sustainable operating level to being fully turned off.

- For storage and DR resources with positive generation only (no charging or dispatchable load increase component; $Pmin_{RA} \geq 0$) and start-up time (SUT) < 90 minutes:
  - EFC = Minimum of (NQC) and ($Pmin_{RA}$ + (180 minutes – Start-up Time) * ARR_{pos})
- For storage and DR facilities with positive generation only (no charging or dispatchable load increase component; $Pmin_{RA} \geq 0$) and start-up time (SUT) > 90 minutes:
  - EFC = Minimum of (NQC – $Pmin_{RA}$) and (180 minutes * ARR_{pos})
- For storage or DR resources with negative generation only (only charging or dispatchable load increase, no discharging or load curtailment; $Pmin_{RA} < 0$ and $Pmax_{RA}$ = 0[8]):
  - EFC = Minimum of ($Pdemand_{min}$ – $Pmin_{RA}$) and (180 minutes * ARR_{neg}),
    plus the absolute value of $Pdemand_{min}$ iff 180 – ($Pdemand_{min}$ – $Pmin_{RA}$)/ARR_{neg} ≥ shut-down time (SDT)
  - The formula above prevents an EFC that assumes the resource would go from $Pmin_{RA}$ at the beginning of the three-hour ramp to an operating point that is between

[8] Facilities with $Pmax_{RA}$ = 0 will automatically have NQC = 0, so that term is not included. Additionally, it is impossible for $Pmax_{RA}$ to be less than zero, so that option is not defined.

$Pdemand_{min}$ and zero, because that operating point would not be physically sustainable. The resource can only ramp to an operating point between $Pdemand_{min}$ and $Pmin_{RA}$ (inclusive), or to zero (shut down). Therefore, the final $Pdemand_{min}$ term is subject to the shut-down time constraint shown, and included only if it is physically achievable for the resource to go from $Pmin_{RA}$ to zero over three hours.

- For storage or DR resources that have both curtail/discharge as well as load increase/charge components ($Pmin_{RA} < 0$ and $Pmax_{RA} > 0$):
  - EFC = Minimum of (NQC) and ($Psupply_{min}$ + 90 min * ARR_{pos}) +
    Minimum of (– $Pmin_{RA}$) and (– $Pdemand_{min}$ + 90 minutes * ARR_{neg})

13.3. Co-Located Storage

Energy storage that is co-located and operated in conjunction with (i.e., is not independently dispatchable from) an RA-eligible conventional facility or variable energy resource (such as wind or solar) will not receive a separate QC or EFC, and may instead modify the QC and EFC of the primary facility (to the extent permitted under the QC and EFC counting rules for that resource type).[9] In the event that a storage facility is independently dispatchable or larger than the co-located energy generator, the energy storage device will be viewed as an independently operating resource and be separately evaluated for QC and EFC. It will also require a separate deliverability study and Scheduling Resource ID (Scheduling ID) to receive an NQC value.

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9 The calculation methodologies for wind and solar facilities have been addressed in a separate staff proposal, sent to the R.11-10-023 service list on January 16, 2014.

13.4. Aggregated Resources

Aggregated storage resources and aggregated DR resources will be granted a composite QC and EFC, based on both the duration over which the individual facilities can operate and the magnitude of their output. An example of this is shown in Figure 1, above. Resource operators may request a QC or EFC that is less than the theoretical maximum of all individual elements summed together, to account for non-performance in a portion of the portfolio (e.g., due to state of charge or due to participant override of a DR dispatch). Storage and DR resources may not be aggregated with one another into a single storage-DR resource at this time.

(END OF APPENDIX B)