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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 and Flexible Procurement Obligations for the 2016 and 2017 Compliance Years.	Rulemaking 14-10-010 (Filed October 16, 2014)

DECISION ADOPTING LOCAL PROCUREMENT AND FLEXIBLE CAPACITY OBLIGATIONS FOR 2016, AND FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM

TABLE OF CONTENTS

Title **Page**

DECISION ADOPTING LOCAL PROCUREMENT AND FLEXIBLE CAPACITY OBLIGATIONS FOR 2016, AND FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM 1
Summary 2
1. Background 3
2. Local RA for 2016 5
   2.1. 2016 Local Capacity Requirements Study 5
   2.2. Continuation of the Local RA Program 8
3. Flexible Capacity Requirements 9
4. Energy Division Proposals 12
   4.1. Transmission and Distribution Loss Factor for Demand Response 12
      4.1.1. Parties' Comments 14
      4.1.2. Discussion 14
   4.2. Qualifying Capacity Calculations for Intermittent Resources 15
      4.2.1. Parties' Comments 17
      4.2.2. Other QC Related Proposals from Parties 20
      4.2.3. Discussion 22
5. Other Party Proposals 27
   5.1. Cost Allocation Mechanism Refinements (MCE) 27
      5.1.1. Parties' Comments 29
      5.1.2. Discussion 30
   5.2. Demand Response Proposals (Calpine) 31
      5.2.1. Parties' Comments 34
      5.2.2. Discussion 35
   5.3. RA Forecast Adjustment Allocation Methodology (CEC) 36
      5.3.1. Parties' Comments 38
      5.3.2. Discussion 40
   5.4. Development of a Bulletin Board (Shell) 42
      5.4.1. Parties' Comments 42
      5.4.2. Discussion 42
   5.5. Allocation of Flexible Capacity Based on Cost Causation (PG&E) 42
      5.5.1. Parties Comments 44
      5.5.2. Discussion 45
   5.6. Modification of Flexible RA Rules for Storage to Include Discharge and Charge (PG&E) 46

TABLE OF CONTENTS
Con't.

Title **Page**

5.6.1. Parties' Comments ... 47
5.6.2. Discussion ... 48
5.7. Changing the Local True-Up Timeline (AReM) ... 48
5.7.1. Parties' Comments ... 51
5.7.2. Discussion ... 51
5.8. Capping Local RA Requirements at System RA Requirement (CAISO) ... 51
5.8.1. Parties' Comments ... 52
5.8.2. Discussion ... 54
5.9. Unbundling Flexible Capacity from System Capacity for all Non-CAM Resources (SDG&E) ... 54
5.9.1. Parties' Comments ... 55
5.9.2. Discussion ... 57
5.10 Unbundling Flexible Capacity for Demand Response and Storage (Joint DR Parties) ... 58
5.10.1. Parties' Comments ... 58
5.10.2. Discussion ... 59
5.11. No NQC Required to Get an EFC (SCE) ... 59
5.11.1. Parties' Comments ... 60
5.11.2. Discussion ... 62
5.12. Two Hour Maximum Cumulative Capacity Bucket (SCE) ... 62
5.12.1. Parties' Comments ... 63
5.12.2. Discussion ... 65
5.13. Storage Parties Proposals/Clarifications (CESA) ... 66
5.13.1. Parties' Comments ... 68
5.13.2. Discussion ... 69
6. SCE/SDG&E DRAM Motion ... 70
6.1. Parties' Comments ... 72
6.2. Discussion ... 74
7. Comments on Proposed Decision ... 75
8. Assignment of Proceeding ... 76
Findings of Fact ... 76
Conclusions of Law ... 79

DECISION ADOPTING LOCAL PROCUREMENT AND FLEXIBLE CAPACITY OBLIGATIONS FOR 2016, AND FURTHER REFINING THE RESOURCE ADEQUACY PROGRAM

Summary

This decision adopts local capacity procurement and flexible capacity obligations for 2016 applicable to Commission-jurisdictional electric load serving entities. These procurement obligations are based on annual studies of local capacity and flexible capacity requirements performed by the California Independent System Operator (CAISO or ISO) for 2016 which seek to ensure that each part of the CAISO controlled grid, including those parts with transmission constraints, have 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, decreased slightly from the prior year; the total of all local areas decreased from 26,345 Megawatts (MW) in 2015 to 25,341 MW in 2016. We also adopt the CAISO's recommendation that the "existing capacity" needed to meet the CAISO local capacity requirement decreased from 25,227 MW in 2015 to 24,425 MW in 2016.

The CAISO's recommended flexible capacity requirement is also adopted. The statewide 2016 flexible capacity requirements range from 7,244 MW (June 2016) to 12,817 MW (December 2016). The statewide flexible capacity needs increased substantially from those identified by the CAISO and adopted by the Commission for 2015. However, much of this change was due to the inclusion of 2,181 MW of incremental behind-the-meter solar production in this year's study.

In addition, this decision makes several minor refinements to the Commission's resource adequacy program for 2016.

1. Background

Pub Util. Code § 380 (as amended by Stats. 2008, ch. 558, Sec. 13)[1] requires that "the commission, in consultation with the California Independent System Operator (CAISO or ISO), shall establish resource adequacy requirements for all load-serving entities." The statute establishes a number of objectives for the Commission to achieve with the resource adequacy (RA) 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 is the first of several phases of this proceeding encompassing the Commission's annual consideration of local capacity and flexible capacity requirements for the next year, and refinements to the Commission's RA program. A *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge* (Scoping Memo), issued on January 6, 2015, identified the issues to be considered in Phase 1 of this proceeding as well as the procedure and schedule for their consideration. Today's decision in Phase 1 determines local and flexible

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

capacity procurement obligations for 2016 applicable to Commission-jurisdictional electric LSEs and addresses further RA program refinements.

Per the Scoping Memo, Phase 2 of this proceeding will address development of a permanent flexible capacity program to replace the interim flexible capacity program for 2015 through 2017 adopted in Decision (D.) 14-06-050 as well as annual local and flexible capacity requirements and refinements to the RA program for 2017. Phase 3 of this proceeding will consider demand response issues related to the RA program.

On December 12, 2014, a Ruling was issued seeking party comment on questions regarding refinements to the RA program, and soliciting party proposals for RA program changes to be considered for the 2016 compliance year. Energy Division provided several informal proposals to the service list, and several party proposals were filed on January 6, 2015 in response to this Ruling. On January 30, 2015, parties filed comments on other parties' proposals, as well as the Energy Division proposals. Energy Division facilitated a workshop on RA program refinement issues on February 9, 2015. A February 23, 2015 Ruling added presentations made at the workshops (including those by Energy Division) to the record. Parties filed comments and replies on the workshop presentations and party proposals on February 27, 2015 and March 11, 2015, respectively.

Comments and/or reply comments were filed by Alliance for Retail Energy Markets (AReM); Calpine Corporation (Calpine); CAISO; California Energy Storage Alliance (CESA); California Large Energy Consumers Association (CLECA); Center for Energy Efficiency and Renewable Technologies (CEERT); Cogeneration Association and the California Cogeneration Counsel

(CHP Parties) Direct Access Customer Coalition (DACC); EnerNOC, Inc. (EnerNOC), Johnson Controls, Inc., Comverge, Inc., and CPower (together, the Joint DR Parties); Green Power Institute (GPI); Imergy Power Systems, Inc., UniEnergy Technologies, LLC, ZBB Energy Corporation, and EnerVault Corporation (EnerVault); Independent Energy Producers Association (IEP); Large-Scale Solar Association; Marin Clean Energy (MCE); NRG Energy, Inc. (NRG); Office of Ratepayer Advocates (ORA); Pacific Gas and Electric Company (PG&E); Shell Energy North America (US), L.P. (Shell); Southern California Edison Company (SCE); San Diego Gas & Electric Company (SDG&E); SolarCity Corporation (SolarCity); The Utility Reform Network (TURN) and Western Power Trading Forum (WPTF).

2. Local RA for 2016

This decision first adopts the amount of local RA needed to meet capacity needs in 2016.

2.1. 2016 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 after a review of the CAISO's LCR recommendations. Following a stakeholder process, the CAISO posted its "2016 Local Capacity Technical Analysis, Final Report and Study Results" (2016 LCR Study) on its website, served notice of the report's availability, and filed it with the Commission on May 1, 2015. No comments were filed on the 2016 LCR Study.

The CAISO states that the assumptions, processes, and criteria used for the 2016 LCR Study were discussed and recommended in a stakeholder meeting, and that, on balance, they mirror those used in the 2007 through 2015 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 expected LCR needs will decrease by about 1,000 MW or about 3.9% from 2015 to 2016. The LCR needs are expected to decrease in the following areas: Sierra and Bay Area due to downward trend for load; Kern and LA Basin due to new transmission projects; and San Diego/Imperial Valley due to downward trend for load and new transmission projects. LCR needs have increased in Humboldt, Stockton, and Fresno due to load growth; in Big Creek/Ventura due to a decrease in needs in the LA Basin and San Diego/Imperial Valley; and in North Coast/North Bay due to a lower requirement in the Pittsburg/Oakland sub-area of the Bay Area.

2016 Local Capacity Requirements									
	Qualifying Capacity			2016 LCR Need Based on Category B			2016 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	21	208	229	118	0	**118**	167	0	**167**
North Coast / North Bay	132	735	867	611	0	**611**	611	0	**611**
Sierra	1195	831	2026	1139	16*	**1155**	1765	253*	**2018**
Stockton	160	434	594	357	0	**357**	422	386*	**808**
Greater Bay	1104	6435	7539	3790	0	**3790**	4218	131*	**4349**
Greater Fresno	282	2647	2929	2445	0	**2445**	2445	74*	**2519**
Kern	99	430	529	214	0	**214**	400	0	**400**
LA Basin	1710	9259	10969	7576	0	**7576**	8887	0	**8887**
Big Creek/ Ventura	584	4951	5535	2141	0	**2141**	2398	0	**2398**
San Diego/ Imperial Valley	228	4687	4915	2850	0	**2850**	3112	72*	**3184**
Total	**5515**	**30617**	**36132**	**21241**	**16**	**21257**	**24425**	**916**	**25341**

* 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.

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**

* 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 have reviewed the CAISO's 2016 Local Capacity Needs Assessment and find it to be reasonable. We adopt the CAISO's recommendations as the basis for establishing local procurement obligations for 2016 applicable to Commission-jurisdictional LSEs.

2.2. 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, D.13-06-024, and D.14-06-050 established local procurement obligations for 2008 through 2015, 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 2016 and thereafter until changed, subject to the 2016 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 2016 in accordance with the adopted policies.

3. Flexible Capacity Requirements

D.13-06-024 and D.14-06-050 adopted a flexible capacity requirement to begin in 2015 and defined guidelines for its implementation. 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.

Following a stakeholder process, the CAISO filed its "Final Flexible Capacity Needs Assessment for 2016" in this proceeding on May 1, 2015. No party filed comments on the CAISO's Final Flexible Capacity Needs Assessment for 2016.

Based on its analysis, the CAISO's identified the maximum flexible capacity needs for each month of 2016 (*see* table below). The flexible capacity needs range from 7,244 MW (June 2016) to 12,817 MW (December 2016). The flexible capacity needs increased substantially from those identified for 2015. However, much of this change was due to the inclusion of 2,181 MW of incremental behind-the-meter solar production in this year's study. As illustrated in the table below, most of the flexible capacity needs are allocated to CPUC-jurisdictional load serving entities (e.g., ~96% of the required need in February 2016).

CAISO 2016 Flexible Capacity Needs

NOTE: All numbers are in Megawatts	CAISO System Flexible Requirement	CPUC Flexible Requirement	CPUC		
			Category 1 (minimum)	Category 2 (100% less Cat. 1 & 3)	Category 3 (maximum)
January	11,103	10,429	6,625	3,283	521
February	10,507	10,050	6,384	3,163	502
March	10,362	9,894	6,285	3,114	495
April	9,989	9,389	5,964	2,955	469
May	7,731	7,417	6,458	589	371
June	7,244	6,967	6,065	553	348
July	7,935	7,546	6,570	599	377
August	7,998	7,606	6,622	604	380
September	9,259	8,825	7,683	701	441
October	10,331	9,886	6,280	3,112	494
November	12,005	11,462	7,281	3,608	573
December	12,817	12,179	7,737	3,834	609

In addition, the CAISO divides 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 adopted 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 and by month, the CAISO established the requirements on a seasonal basis. Accordingly, the CAISO proposes percentage maximum or minimum limits for different categories of flexible resources applicable to summer (May - September) and winter (all other months) months. The application of these percentage limits on categories of flexible resources to Commission-jurisdictional entities is shown in the table above.

We have reviewed the CAISO's Final Flexible Capacity Needs Assessment for 2016 and find it to be reasonable. We adopt the CAISO's recommendations as the basis for establishing flexible procurement obligations for 2016 applicable to Commission-jurisdictional LSEs.

4. Energy Division Proposals

4.1. Transmission and Distribution Loss Factor for Demand Response

In D.09-06-028, the Commission directed that the qualifying capacity (QC) of demand response (DR) resources be based on the Load Impact Protocols (LIPs) adopted in D.08-04-050. In D.10-06-036, the Commission further determined that the QC values for DR resources should be "grossed-up" for avoided line losses because the DR resources are supplied at the customer meter level and, therefore, eliminate the need to account for transmission and distribution (T&D) line losses. The QC Manual directs Energy Division staff to calculate the avoided line losses using a 3% transmission loss rate and a distribution loss rate "from the most recent available data submitted in each Investor Owned Utility's (IOU)s current or previous general rate case."

The Long Term Procurement Planning (LTPP) proceeding biannually adopts planning assumptions and scenarios which include T&D loss factors, for use in the Transmission Planning Process (TPP) and the Commission's future LTPP Proceeding. The most recent LTPP assumptions and scenarios were adopted in a March 4, 2015 Ruling in the 2014 LTPP proceeding (Rulemaking (R.) 13-12-010). The T&D loss factors are supplied by the California Energy Commission (CEC).

Energy Division identifies a number of problems with the current approach. First, the avoided line loss values are often located in confidential workpapers in General Rate Case application proceedings, causing difficulty locating these workpapers and the line loss figures contained within them, and difficulty determining whether the line losses figures in the workpapers are cumulative or separable. Second, the line loss figures currently used to gross-up DR resources in the RA proceeding are not the same as those currently used in the LTPP or the CAISO's TPP.

Energy Division proposes to use the avoided line loss factors from the mostly recently adopted LTPP assumptions and scenarios document to develop QC values for DR resources. The currently adopted LTPP assumptions and scenarios values are shown in the table, below.[2]

[2] *See* R.13-12-010, March 4, 2015 ruling.

Transmission and Distribution Loss Figures

	PG&E	SCE	SDG&E
Peak, distribution losses only	1.067	1.051	1.071
Peak, transmission and distribution losses	1.097	1.076	1.096

For purposes of "grossing-up" QC values for DR resources to account for avoided line losses in the RA process, Energy Division proposes to use the adopted LTPP assumptions and scenarios document available at the time Energy Division allocates DR QC values for the next RA compliance year (this allocation process usually occurs in the summer prior to each RA compliance year).

4.1.1. Parties' Comments

All commenting parties except PG&E support Energy Division's proposal to adopt the same line losses as those adopted in the recent LTPP assumptions and scenarios document. SCE, CLECA, and ORA support the proposal since it would increase consistency across proceedings. ORA adds that it would increase transparency, and reduce administrative burden on Energy Division staff. While PG&E generally supports the proposal, PG&E would like further information on how the CEC derived the current line loss factor values in the most recent LTPP/TPP assumptions and scenarios document, and how these factors will be derived for future LTPP/TPP assumptions and scenarios documents before it takes a formal position.

4.1.2. Discussion

Energy Division's proposal on avoided transmission and distribution line losses will increase consistency across Commission proceedings and reduce administrative burden. We therefore adopt the Energy Division proposal to use the second row of the table above, specifically the avoided transmission and distribution line loss factors from the most recently adopted LTPP assumptions and scenarios document to develop QC values for DR resources. Additionally, we agree with PG&E that there is a need to clarify how the CEC calculates the T&D loss factor used in the LTPP and TPP. However, we believe this clarification should be made in the LTPP proceeding. Parties should request this clarification in their comments to the next LTPP assumptions and scenarios ruling.

4.2. Qualifying Capacity Calculations for Intermittent Resources

The Commission adopted a methodology manual in D.09-06-028 that codified the calculation of QC for different types of generating resources as they count towards RA obligations. The adopted QC Calculation Manual lays out the method used to calculate the QC for dispatchable and non-dispatchable generators. Energy Division's January 6, 2015 proposal highlights three areas where the existing QC manual leads to incorrect or unintended outcomes, and proposes remedies for these areas of concern.

The first concern is that grouping solar photovoltaic (PV) and solar thermal into one category when using the exceedance methodology masks the real differences in the performance and generation profiles of these two distinct types of solar generators, resulting in QC technology factors that do not accurately represent the differing contributions of these two technology types towards meeting RA needs. Energy Division proposes revising the QC Calculation Manual to specify calculation of two sets of technology factors for solar facilities: one set specifically for solar thermal facilities and another for PV facilities.

The second Energy Division proposal addresses the problem of including test data (Megawatt hours of actual energy production observed before a generator becomes commercially operable) in QC calculations. This practice leads to QC values that reflect a distorted performance history that is based on partial operation of a facility and fails to realistically represent the contribution of facilities towards meeting RA needs. Energy Division proposes to amend the QC Calculation Manual to explicitly exclude test data from the calculation of QC values. Instead, meter data would be used beginning on the date the facility reaches commercial operation, and QC would be calculated based on the technology factors up until that point. When conducting QC calculations, staff proposes to use historical meter data beginning on the date that the entire facility (all stages) has reached commercial operation for generators that come online in stages.

Finally, Energy Division proposes an alternative treatment for facilities whose historical production may be impacted by forced or scheduled outages. Currently, proxy data, rather than historical data, are used in QC calculations for hours when a facility is impacted by forced, planned, or ambient not related to temperature outages. This calculation methodology was intended to avoid double penalties for generators also subject to performance penalties from the CAISO. However, it sometimes results in elimination of a large part of the performance history of facilities. Moreover, these facilities may only be slightly or insignificantly impacted by outage. In such cases, staff must discard extensive amounts of usable data. Energy Division proposes two options for amending the QC Calculation Manual to create a mechanism to manage these situations:

> **Option 1**: Energy Division proposes eliminating the entire section of the QC Calculation Manual that details downloading and processing of generator outage data. Instead, the QC for intermittent facilities would be calculated using the entire dataset regardless of the generator's outage history.

Option 2: As an alternative, Energy Division proposes to set a six month threshold at which staff would no longer generate proxy data to replace performance data potentially impacted by outage. If a facility was impacted by outage for more than six months during the three years of performance in the dataset, Energy Division would use the entire dataset without consideration of outage history. If the facility was impacted by outage for six months or less, then Energy Division would follow the direction of the current QC Calculation Manual and generate proxy data from the other performance data in the dataset.

4.2.1. Parties' Comments

Energy Division's proposal to disaggregate the technology factors for solar generators into PV and solar thermal drew broad party support. GPI calls this proposal a "no-brainer" and calls for its immediate implementation. PG&E and SCE both support this proposal, and further, suggest that at some point disaggregating the technology factors into additional classes, such as fixed or tracking PV, may be appropriate. ORA, while supporting the proposal, requests more information and sought to ensure that the proposal could be implemented one year ahead of the development of the Effective Load Carrying Capacity (ELCC) values. ORA also requests access to the performance data that Energy Division used to assess differences between performance of solar thermal facilities and PV facilities.

Energy Division's second proposal is to exclude test data from the dataset used to calculate the QC of facilities. GPI strongly supports this proposal, and CAISO, IEP, and ORA also added support. No party opposes this proposal. CAISO supports the proposal, and suggests calculating the QC of a facility based on the weighted average of the technology factors and actual performance data for periods when only a portion of the facility is online.

Responses to Energy Division's proposal to eliminate the creation of proxy data to replace performance for hours impacted by forced or scheduled outages were mixed. All parties agree with the identification of the problem. However, many parties are uncertain that enough material is on the record to adopt Energy Division's proposal. Several parties propose alternative solutions.

CAISO strongly supports Energy Division's proposed Option 1, noting the congruence with provisions in the newly proposed RA Availability Incentive Mechanism (RAAIM) enhancements to exempt wind and solar facilities from the RAAIM. PG&E also supports Option 1, noting that "the inclusion of the proxy data does not appear to be meeting its intended purpose"[3] and that this practice makes the QC calculations more complicated.

IEP raises questions about the proposal but offers no alternative, noting that if the goal of the calculation is to ensure that no double penalizing of QC due to outages is occurring, both of the "options presented by Energy Division may not achieve that goal."[4] SCE opposes adoption of this Energy Division proposal, doubting that "the record is developed enough to contemplate a change to the use of outage data with the exceedance calculation."[5] SCE requests additional information to explain the proposal, specifically a chart that shows MW affected by outages, not number of units. SDG&E echoes SCE's request.

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[3] PG&E Comments, January 30, 2015, at 4.

[4] IEP Comments, January 30, 2015, at 3.

[5] SCE Comments, February 27, 2015, at 6.

GPI requests clarification about this Energy Division proposal. GPI notes the data in the proposal that illustrate the portion of facilities that have outages extending beyond six months, and assumes that these facilities with outages that long are offline or shutdown. GPI proposes that facilities with extended outages be treated as new facilities.

SDG&E suggests a means to achieve the goal of generating proxy data to mask the potential negative impacts of hours when the facility is affected by scheduled or forced outage. SDG&E suggests examining the newly standardized list of outage reason codes in the CAISO's new OMS system and making a clear list of the appropriate set of outages that Energy Division believes lead to genuine derate impacts, and only generating proxy data when those types of outages occur. This is a reduced and more nuanced version of Energy Division's current practice of proxy data creation.

WPTF suggests an alternative to Energy Division's two options, which would maintain the creation of proxy data in some cases, but not in others. While WPTF notes that proxy data is currently created in order to prevent the double penalty levied on intermittent resources when their production is decreased by outages while they also receive penalties from CAISO for the outage, WPTF notes two developments that alleviate that. First, the CAISO's proposed RAAIM mechanism potentially exempts wind and solar facilities. As an alternative to Energy Division's proposal, WPTF proposes the following:

1) In the event that outages do not affect production of a facility (such as in the case of outages that affect AGC or communications equipment but not generator equipment), no creation of proxy data is warranted.
2) In the case of outages that partially derate a facility, the remaining production could be scaled up to the full

capacity of the facility to simulate possible production from the facility without outage derate.

3) If the facility is completely unable to produce electricity due to outage, then proxy data would be created.

NRG supports WPTF's proposal as superior to either of Energy Division's options.

4.2.2. Other QC Related Proposals from Parties

In addition to Energy Division's QC-related proposals, parties also submitted their own QC proposals into the proceeding. PG&E proposes a redefinition of dispatchability for cogeneration facilities that are unable to bid into the real-time market, but are nevertheless able to submit schedules into the day-ahead market and respond to some limited CAISO dispatch instructions. PG&E proposes that the Commission should modify the QC definitions to allow RA resources that are capable of operating in accordance with day-ahead and pre-day-ahead scheduling instruction, but are not fully capable of responding to real-time dispatch instructions, to be given a QC value based on Pmax, rather than based on historical output. This would recognize the QC value of a resource that can be scheduled to its Pmax when the CAISO finds it beneficial to do so even though there may be some dispatch restrictions. Also, PG&E recommends a revision of the QC manual to incorporate all changes that have occurred since its original adoption in 2010. PG&E asserts that the manual is out of date and does not reflect the latest adopted policy on the calculation of QC.

GPI, TURN, NRG and ORA support PG&E's proposal to create a new category of QC resources because under the current rules, certain resources seeking to provide additional flexible capacity may, in order to assist grid operations, experience scheduling instructions in the CAISO markets that reduce the output of those resources which would therefore decrease their future QC value. PG&E's proposal to use PMax rather than historical output to calculate QC values for these resources would reduce the disincentive to restructure contracts for increased flexibility.

The combined heat and power (CHP) parties conditionally support PG&E's proposal since they claim it corrects a flaw in QC accounting where the reduced output of a facility that switches from baseload to pre-scheduled operation will result in a reduction in QC despite the capacity of the resource remaining the same. However, the CHP parties seek clarification that the proposal applies to all units that are scheduled in the day-ahead market but are not dispatchable in the real-time market and that the proposal expressly provides that: (a) the increased QC does not create an obligation on the part of the pre-scheduled facility to provide that increased capacity; and (b) the pre-scheduled facility may voluntarily agree and commit to provide such RA capacity, but solely at its election.

SDG&E supports PG&E's proposal that resources that are bid into the CAISO's day-ahead market should be fully counted based on PMax. However, resources that are pre-scheduled into the CAISO's day-ahead market should continue to be assigned a QC value based on historical output because there is no guarantee the resource would be scheduled during the peak hours of a day. If the new classification of QC resources is adopted, SDG&E recommends that the scheduling coordinator for these non-dispatchable resources notify Energy Division and the CAISO of any change in resource classification. The scheduling coordinator of the resource could provide materials to verify a contracted change in classification, and once verified, the resource would receive its QC based on the methodology established for dispatchable resources until the end date of the contract.

The CAISO opposes the proposal, preferring that the Commission assess resources that are pre-dispatched prior to the CAISO's day-ahead market based on historic output. If, however, the proposal is adopted, the CAISO prefers using a three-year rolling average of historic availability data to using PMax to calculate QC values.

4.2.3. Discussion

Energy Division's first proposal to disaggregate technology factors for solar PV and solar thermal facilities is broadly supported, and we adopt it here. Although Energy Division is also working to complete and publish a study of the ELCC of wind and solar facilities, in the interim, revisions to current QC calculation methods are needed.

We also adopt Energy Division's second proposal to eliminate test data from the QC calculation. Parties broadly support the proposal which fairly differentiates between calculating expected performance of the facility and using as much data as is available. We find it to be consistent with the purpose of QC calculations to represent the expected contribution of facilities towards RA obligations. The CAISO's amendment to the proposal regarding the use of a weighted average of technology factors and historical performance represents a fair and innovative remedy for the problem of facilities that come online in phases. QC calculations are intended to balance the use of as much historical performance as possible while also providing an accurate forecast of the full production of the facility in the subsequent year. The CAISO's amendment does just that, enhancing Energy Division's proposal to further our goals in calculating QC for resources. Therefore we adopt Energy Division's second proposal as amended by the CAISO in their comments. QC for resources that come online in phases will be based on historical production after the phase reaches commercial operation excluding test data. Remaining phases under construction will be assessed using technology factors and a MW weighted average of each part will comprise the total QC of the facility.

Energy Division's third proposal to reassess the use of proxy data in QC calculations elicited the most comment. Several parties propose variations to the proposal that would continue to use proxy data, while at the same time addressing some of the issues highlighted in Energy Division's proposal.

GPI proposes that facilities with outages in excess of six months out of the previous 36 be classified as units that have shut down and argues that their QC calculation should to be calculated as if they were new facilities just coming online. GPI makes the assumption that an outage in excess of six months will have disabled the plant completely. However, GPI has not shown that an outage extended out to six months or more would affect the facility's output; it may be that an outage is insignificant or affects communications equipment while the facility continues to operate throughout the outage event. Without further information, we will not adopt GPI's proposal to classify those facilities as new or shut down.

The proposals submitted by WPTF and SDG&E are similar to each other; both rely on Energy Division examining the list of outage types and only generating proxy data when actual derates are expected to occur. For example, outages affecting communication equipment would not derate the MW production of a facility so when those outages occur, there would be no proxy data generated. WPTF/SDG&E's proposed refinement to the generation of proxy data, where Energy Division would parse the list of generator outage codes and be more judicious in discarding data potentially impacted by outage, rests on the assumption that a facility affected by outage is unfairly penalized by lower production when the facility could be derated due to outage. We are not convinced that a facility's production is always higher or lower in the event of an outage. We are also not convinced that production during an outage is not the accurate prediction of the generation of an intermittent facility. For this reason, we adopt Energy Division proposed Option 1, for 2016 compliance year only, and commit to open this issue again in Phase 2 of this proceeding when studying RA for the 2017 RA compliance year.

It is clear that the "double penalty" issue is no longer pertinent, due to the future exemption encompassed in CAISO's RAAIM mechanism, but the "double penalty" issue is not the only reason for the generation of proxy data in the first place. Notwithstanding uncertainty around adoption of the CAISO's RAAIM proposal by FERC, and it's enactment in 2016 RA compliance year, the generation of proxy data for facilities undergoing forced or planned outage does not provide certainty that the proxy data itself does not constitute a penalty. We approve this proposal not solely because of our confidence in the adoption of the CAISO's RAAIM proposal, which removes the "double penalty" but also in the interests of preserving as much production data as possible in calculating the QC of non- dispatchable generators. With attention to the purpose of QC calculations, we do not believe that the generation of proxy data provides a good means of forecasting the production of a facility in the subsequent RA compliance year. We want to be conservative in application of calculations and careful not to distort forward predictions by removal of any portion of actual production data. We do not have generation of proxy data would unambiguously raise the QC of facilities with some affects from outages. Therefore, we will continue to study the operation of the CAISO's new OMS system and reassess the viability of WPTF/SDG&E's proposal during the 2016 RA compliance year.

PG&E's proposal regarding prescheduled QF facilities is intended to clarify an ambiguous area in the current QC procedures. Facilities that can be scheduled into the CAISO day-ahead market, but cannot be bid or dispatched in the real-time market may already be considered dispatchable for QC purposes. The QC rules do not clearly define dispatchable guidelines, leaving the definition up to the owner or scheduling coordinator (SC) of the facility to determine. Energy Division prepares a preliminary QC list each year that delineates which facilities are dispatchable and which are not. The owner or SC of a facility then can change the determination in comments, and Energy Division reviews the QC of the facility.

The discretion shown by generator owners in determining their facilities as dispatchable or not and the ensuing impacts on QC calculation relative to that discretion create uncertainty and potentially some inaccuracy. We believe more clarity in the QC manual is warranted. Although the Proposed Decision (PD) adopted PG&E's proposal, we are persuaded by CAISO's comments on the PD that PG&E's proposal will remove incentives to perform from predispatched RA resources. PG&E's proposal would redefine "dispatchability" for QC calculations to mean any facility that could schedule for any amount regardless of their ability to participate in the real time market. SDG&E, in their comments on the PD, rightly points out that any facility (wind, solar, etc.) that could schedule any MW level into the day ahead market, even if they were unavailable for redispatch later, could be classified as dispatchable. This was not our intention, thus, we will amend the QC manual to define dispatchability specifically as the ability to:

(1) schedule or bid into the CAISO day ahead market; and

(2) be available for economic redispatch in the real time market.

For "'pre-dispatch" RA resources, we adopt CAISO's alternative proposal and decide that those facilities such as QF resources that are able to submit a schedule into the day ahead market, but are not available for redispatch in the real time market, would be termed "Pre-dispatch." Their QC would be based on their scheduled MW amounts in the day ahead market, not their settlement data; any adjustments to their schedules or acceptance or denial of dispatch would not affect their QC. Other facilities that are not pre-dispatched would still be treated as non-dispatchable.

To ensure that the application of this new "pre-dispatch" category applies narrowly for the time being, only QF cogeneration facilities can be qualified as "pre-dispatch." QC for other types of non-dispatchable resources is unaffected. Energy Division will amend the QC manual to create a new category of QC calculations applicable only to pre-dispatch QF cogeneration facilities; all facilities that are not QF cogeneration facilities will be impacted or affected by this decision.

Due to data limitations, Energy Division staff is unable to fully implement CAISO's alternative proposal; Energy Division only has bid data for the immediately previous year. Thus, Energy Division will calculate QC for those QF cogeneration facilities that wish to be classified as "predispatch" using the one year of bid data and two years of settlement data. Each year, Energy Division will collect one more year of bid data, until in two years, Energy Division will be able to calculate QC for predispatch QF cogeneration facilities purely with bid data.

We appreciate PG&E's proposal to ensure the QC manual is updated and republished once the changes we adopt in this decision are set in place. While we have no specific examples of the QC manual being out of date, we also are reminded that what is published after this decision should be the most complete and accurate document possible.

Energy Division is directed to revise the QC manual to incorporate all of these changes, ensure that the manual is fully updated, and reissue it on the Commission website for parties to reference as soon as is possible after approval of this decision.

5. Other Party Proposals

5.1. Cost Allocation Mechanism Refinements (MCE)

D.06-07-029 adopted a process known as the Cost Allocation Mechanism (CAM), which allows the Commission to designate IOUs to procure new generation within an IOU's distribution service territory, with the costs and benefits associated with development for these new resources to be allocated to all benefiting customers. All benefiting customers are to include: bundled-utility customers, Direct Access customers and Community Choice Aggregator (CCA) customers. The LSEs serving these customers are allocated the rights to the capacity in each service territory, which are applied towards meeting the LSE's RA requirement. The LSEs receiving a portion of the CAM capacity pay only for the net cost of the capacity, which is the net of the total cost of the power purchase contract price minus the energy revenues associated with dispatch of the contract.

The CAM mechanism was later expanded by D.10-12-035, which adopted the Qualifying Facilities/CHP settlement, to include CHP resources that the IOUs procured to meet their greenhouse gas targets.

On January 16, 2015, MCE proposed refining the current process by which CAM reliability resources are passed through to non-IOU LSEs.[6] MCE argues that "the ongoing capacity allocation process results in over-procurement and stranded costs."[7] MCE also proposes that a workshop be held to consider refinements and to create a baseline understanding on the issue.[8]

During the February 9, 2015 RA workshop, MCE proposed to unbundle the CAM net capacity costs so that the net capacity costs would be equal to a reliability cost plus an RA capacity cost. Additionally, MCE proposed that the reliability cost of the CAM resource, rather than the net capacity cost, be passed through to all benefiting LSEs. The capacity costs and benefits would remain with the IOU that procured the CAM resource.[9]

MCE argues that this unbundling solution would provide CCAs the procurement autonomy they need to efficiently procure to meet their RA obligation without the exposure to uncontrollable CAM allocation costs.[10] In addition to the unbundling proposal, MCE also presented two alternative solutions: 1) Eliminate the variability of CAM allocations to eliminate discrepancies between September and monthly CAM allocations, or 2) Weight

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[6] MCE Comments, January 16, 2015, at 1.

[7] MCE Comments, January 16, 2015, at 3.

[8] MCE Comments, January 16, 2015, at 5.

[9] MCE RA workshop presentation posted: http://www.cpuc.ca.gov/NR/rdonlyres/6B11AFD6-FED4-42F9-B032-5B9B80234720/0/MCECleanEnergy.pptx

[10] MCE Comments at 3.

monthly CAM allocations to make projected and actual CAM allocations proportionate with seasonal capacity requirements.[11]

5.1.1. Parties' Comments

MCE's proposal to unbundle CAM net capacity costs is broadly opposed. SDG&E argues that the proposal is unlawful and out of scope.[12] CLECA contends that MCE's proposal is inconsistent with statute, and that the proposal cannot be implemented without a change to statue.[13] SCE notes that there is not currently a mechanism to value RA and without one the accounting of the proposal will be inaccurate.[14] Additionally, SCE states that MCE's proposal should be raised in the 2014 LTPP proceeding (R.13-12-010), which currently has changes to the Cost Allocation Mechanism included in its scope.[15]

AReM points out that the current list of CAM resources posted on the RA compliance website does not include CAM resources that have been approved but are not yet operational. AReM "requests that the Commission consider providing additional online information to assist CCAs and electric service providers (ESPs) in minimizing over-procurement."[16] AReM requests that this include the Net Qualifying Capacity (NQC) of all approved CAM resources that are expected to become operational during the year and the month in which the

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11 MCE RA workshop presentation posted: http://www.cpuc.ca.gov/NR/rdonlyres/6B11AFD6-FED4-42F9-B032-5B9B80234720/0/MCECleanEnergy.pptx slide 16

12 SDG&E Comments at 12.

13 CLECA Comments at 6.

14 SCE Comments at 4.

15 SCE Reply Comments at 5.

allocation would take effect. Additionally, AReM requests that the IOUs provide public forecasts of CAM resource online dates at least every quarter.[17]

MCE recommends an alternative solution for refining the current CAM capacity allocation process that would mitigate some of their concerns. MCE proposes that Energy Division "provide twelve distinct forecast values, one per month, for the full year-ahead CAM-related capacity allocation forecasts."[18] CLECA also suggests a similar alternative proposal that Energy Division "re-evaluate its process for allocating CAM costs, considering more months than just August in its initial allocation."[19]

No party objects to this 12 month initial CAM allocation. PG&E supports allocating 12 months of CAM capacity benefits in the year-ahead time frame. PG&E states this change "would increase transparency of CAM allocation values for all LSEs."[20]

5.1.2. Discussion

MCE's proposal to unbundle CAM net capacity costs would require a change to the CAM mechanism established in D.06-07-029. As noted by several parties, changes to CAM have been scoped into the 2014 LTPP proceeding (R.13-12-010). We will defer consideration of this issue to the LTPP proceeding.

AReM's request that the Commission provide additional online information to assist CCAs and ESPs in minimizing over-procurement is

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16 AReM Comments at 3.

17 AReM Comments at 3.

18 MCE Comments at 5.

19 CLECA Comments at 6.

20 PG&E Reply Comments at 8.

reasonable, since it would increase transparency but not change the CAM mechanism. Following the annual and quarterly allocation of CAM, Energy Division should publish a list of the CAM resources (including capacity values and contract dates) that were included in the allocation on its RA compliance website.

MCE's proposal that that Energy Division "provide twelve distinct forecast values, one per month, for the full year-ahead CAM-related capacity allocation forecasts" is reasonable and would not constitute a change to the CAM mechanism. Providing LSEs with this information will help them to minimize over-procurement and improves transparency needed for efficient procurement planning. Energy Division should provide LSEs with twelve monthly CAM values as part of its annual year-ahead allocation. The details of this allocation will be addressed in the annual RA guide.

5.2. Demand Response Proposals (Calpine)

The 2012 LTPP Assumptions and Scenarios specified, as an interim approach for local reliability purposes, that only DR programs that are able to respond to dispatch instructions within 30 minutes or less, including notification time, are to be modeled. These DR programs are referred to as "First Contingency." However, the CAISO contends[21] that DR that can be relied upon to mitigate first contingencies in local reliability studies participates in, and is dispatched from, the CAISO market in sufficiently less time than 30 minutes[22] from when it is called upon.

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[21] 2015-2016 TPP study: http://www.caiso.com/Documents/2015-2016FinalStudyPlan.pdf

[22] The 30 minute requirement is based on meeting NERC Standard TOP-004-02. Meeting this requirement implies that programs may need to respond in 20 minutes, from customer

Footnote continued on next page

The current DR Rulemaking (R.13-09-011) expects to restructure DR programs to better meet CAISO operational needs and has already produced one major policy decision towards that goal. The rulemaking is expected to issue additional decisions that enable demand response to be more useful for grid needs, but CAISO has several tasks it must complete in order to make integration of DR possible.

The 2014 LTPP Assumptions estimated that approximately 1,100 MW would be available to mitigate first contingencies within the San Diego and LA Basin local reliability areas by 2024. By contrast, the 2012 LTPP Assumptions estimated that approximately 200 MW of DR would be available for the same area. Due to the uncertainty regarding what amount of DR can be projected to meet this first contingency criteria, in the most recent TPP study (2015-2016), the CAISO modeled both the 2012 and 2014 DR Assumptions.

In D.10-06-036 the Commission adopted the following DR measurement hours, in which the average expected load impact would be measured for purposes of calculating its QC value.

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

notification to load reduction, in order to allow for other transmission operator activities in dealing with a contingency event.

decision.	

The December 12, 2014 ruling in this proceeding asked parties to consider if the current eligibility requirements for DR are appropriate. The ruling also asked parties if the measurement hours should be changed for any resources and if so, how. Additionally, the ruling asked if the NQC for behind the meter energy resources, registered as PDR resources, should be changed.

In D.14-12-024, the Commission adopted the DR bifurcation decision, which specifically established a load modifying DR valuation working group and directed the working group to file a report, providing recommendations by May 1, 2015. Following this decision, the January 6, 2015 scoping ruling in this proceeding specified that Phase 3 of this proceeding would address the recommendations that were filed in the load modifying DR valuation working group's May 1, 2015 report.

Calpine provides three proposals related to DR resources:

1. Calpine proposes that local RA DR resources should be dispatchable in 20 minutes. According to Calpine, the CAISO recently issued guidance to SCE that reduced the maximum response times for the DR it procured to address prospective LCR to 20 minutes. This proposal would create consistency with the CAISO's direction and ensure resources were available for rapid response to contingencies.
2. Calpine proposes that RA measurement hours include more early evening hours in the summer in order to adjust for shifts in load peaks to the late afternoon and early evening hours as a result of changes in load shapes and the growth of variable generation. Calpine proposes that rather than the current RA measurement hours of 1:00 to 6:00 p.m. during the summer months (April – October) and 4:00 to 9:00 p.m. during the winter months (November –

March), RA measurement hours for DR include the 4:00 to 9:00 p.m. hours throughout the year.

3. Calpine proposes that if substantial amounts of DR remain load-modifying, this RA proceeding should address the RA counting of load-modifying DR to ensure it is consistent with the counting of supply-side DR. D.14-12-024 delegated issues related to the valuation of load-modifying DR, including RA valuation, to working groups. Calpine argues that the RA counting rules developed in these working groups for load-modifying DR should be no less stringent than the rules for supply-side DR developed in this proceeding.

5.2.1. Parties' Comments

The CAISO and IEP support the first Calpine proposal that supply-side demand response resources that count as local capacity must be capable of being dispatched and fully curtailed within 20 minutes because fast response is a necessary characteristic for an energy-limited supply resource, such as supply-side demand response, whose purpose is to help the system fully recover within 30 minutes after a contingency has occurred. NRG offers that additional discussion and consideration is necessary before Calpine's proposal could be adopted given current requirements for DR, and the lack of specificity about the minimum operating characteristics needed for DR to count towards RA and local RA obligations. PG&E recommends rejecting Calpine's proposal since no party has made a compelling case for its necessity.

The CAISO opposes the third Calpine proposal because supply and load modifying demand response resources have very different load impact objectives. The purpose of a supply-side demand response resource is to meet the system's day-to-day load serving needs, while the purpose of a load modifying resource is to persistently reduce the load and, therefore, the number of supply resources that must be procured to serve that load in the first instance.

Accordingly, requiring supply and load modifying resources to have the same or similar characteristics is not necessary given their different load impact objectives.

PG&E opposes all proposals to modify the RA counting rules for DR resources at this time because the Scoping Memo clearly indicates that any DR RA issues are to be addressed in a Phase 3 of this proceeding, which is to commence, if warranted, after the "Valuation Working Group" report contemplated in D.14-12-024 has been issued, and incorporated into this docket. According to PG&E, considering Calpine's proposal would circumvent the established timeline for consideration of modifications. NRG supports PG&E's position to defer all three topics, while the CAISO feels that the 20 minutes proposal is both timely and appropriate.

5.2.2. Discussion

The current LTPP proceeding has adopted DR values that are assumed to mitigate first contingencies. The most recent TPP study has modeled this assumption. The current DR proceeding is still in the process of making demand response more reliable while the CAISO is in the process of integrating DR resources into CAISO markets. Demand response programs need time to respond to RA rule changes. Given that the Commission is currently evaluating the 2016 Load Impacts for 2016 RA DR values, the current programs, receiving local credit, will have been given no time to respond to this rule change. Given the lag in DR program response time as well as the current market participation uncertainties, we cannot adopt a 20 minute local dispatch requirement for 2016. However, we do believe that this issue should be re-evaluated in Phase 3 of this proceeding to be considered for future compliance year RA rules.

Calpine's second proposal, regarding the current measurement hours for DR resources, is a possible alternative to the current measurement hours. However, without a CAISO study to support the recommended changes to the measurement hours, we cannot adopt this proposal. We encourage the CAISO to look at the current measurement hours, as suggested in its comment, and file this study in Phase 3 of this proceeding. If a study is filed, Phase 3 of this proceeding could be expanded to consider the measurement hours for DR resources.

Calpine's third proposal, related to the valuation of load modifying DR, will be addressed in Phase 3 of this proceeding as directed in the January 6, 2015 Scoping Memo. The Scoping Memo states that, if warranted, a Phase 3 of this proceeding will commence to cover DR RA issues once the Valuation Working Group has filed a compliance report on RA valuation issues for load-modifying demand response. This report was filed on May 1, 2015. Valuation of load modifying DR will be considered in Phase 3 of this proceeding.

5.3. RA Forecast Adjustment Allocation Methodology (CEC)

D.04-10-035[23] and D.05-10-042[24] established the Commission'sRA framework, under which LSEs would submit load forecasts to the CEC that would be adjusted for coincidence and programmatic impacts (energy efficiency, distributed generation and demand response) as well as be assessed for plausibility and consistency with the CEC's aggregate forecast. D.05-10-042 noted that "[t]here is a need for the three IOUs to prepare and document the hourly impacts of EE, DR, and DG programs within their service areas and to

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[23] D.04-10-035 at 16-21.

[24] D.05-10-042 at 29-32.

provide these impacts to the CEC for use in the adjustment of LSE load forecasts."[25]

In R.04-04-003 Phase 2 workshops, two approaches to coincident adjustments were discussed: (1) use of historic coincident factors ("historic approach") and (2) determination of coincident peaks directly from the hourly load forecasts submitted by the LSEs ("forecast approach"). D.05-10-042 adopted the "historic approach" and stated that, "[w]hile, in theory, forecasts might be more accurate (and as CAISO observes, more in line with our decision to use the best estimate rather that the current customers approach), we have insufficient experience with these forecasts to justify making that conclusion."[26]

D.05-10-042 also adopted an "average" coincident adjustment methodology[27] that was later modified in D.12-06-025[28] to an "LSE specific" coincident adjustment methodology. The change was based on the fact that each LSE has a different load shape and thus makes a different contribution to the CAISO's peak demand which is used to set system RA requirements. The method adopted in D.12-06-025 still relies on historical hourly metered data (historic approach).

During the 2015 year-ahead forecast adjustment process, the CEC and the Commission received several questions and concerns from parties regarding the adopted process and the transparency of that process. In response to parties

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25 D.05-10-042 Finding of Fact 15.

26 D.05-10-042 at 36.

27 D.05-10-042 adopted an average coincident adjustment factor methodology which uses historical coincident factors and the same coincident adjustment factor for all.

28 D.12-06-025, Ordering Paragraph 4.

concerns and requests, the CEC presented the current RA forecast adjustment allocation methodology during the February 9, 2015 RA workshop.[29] In addition to the presentation, a write up of the current methodology was also distributed.

The presentation and write up included clarification of:

1.) The year-ahead forecast timeline and adjustments;

2.) The coincident adjustment methodology (inputs and process);

3.) The weather normalization methodology for short-term load forecast (inputs and process); and

4.) Implementation issues.

5.3.1. Parties' Comments

CLECA supports the current coincident methodology because it better follows cost causation than the previously adopted average method did. However, CLECA argues that some elements of the coincident adjustment methodology's implementation raise consistency and transparency concerns.[30] Specifically, CLECA has concerns about the accuracy of the load migration assumption, the purpose of weather normalizing coincident factors, and the inconsistent calculation of the coincident factor adjustments between LSEs (using top 3 hours or the top 5 hours or the median of those hours).

CLECA requests a RA forecast methodology workshop in Phase 2 that includes a review of other Independent Systems/Regional Transmission Operator allocation methodologies. CLECA also supports having the CAISO

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[29] http://www.cpuc.ca.gov/NR/rdonlyres/41C74741-9E5A-4F44-8DC4-3ED75B6D4A3E/0/CEC.ppt

[30] CLECA Comments at 8.

publish the system peaks used in the coincident adjustment calculation, which would support greater transparency.[31]

DACC argues that the coincident adjustment process, adopted by D.12-06-025 "lacks transparency and the accuracy of the results cannot be easily verified."[32] DACC requests that the Commission include a discussion of the need for transparency and accuracy in the Phase 1 RA decision. Additionally, DACC proposes that a workshop be held to vet the current process and adopt identified improvements for implementation by the end of 2015.[33] AReM requests that if the methodology does change, the "quantitative effects of the proposed change on each LSE be specified" and the proposed change, if effects are significant, be phased in over several years.[34]

Shell argues that the CEC's presentation of the current load forecast methodology "reflects a 'black box' methodology that relies on the exercise of discretion by a small group of individuals at the CEC." Shell further states that the coincident adjustment process relies too heavily on ESPs' historical load information, which may not always be reflective of the same customer load that is assumed in the year-ahead load forecast.[35] Shell also argues that adjustments should not be made to some LSE load forecasts and not to others.

Shell makes four specific requests:

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[31] CLECA Comments at 8-10.

[32] DACC Comments at 2.

[33] DACC Comments at 4.

[34] AReM Comments at 5.

[35] Shell Energy Comments at 3-4.

1.) The CEC and the CAISO should publish the five highest CAISO system peak loads used in the annual coincident adjustment calculation;

2.) The CEC should publish a step by step process of its methodology;

3.) Adjustment factors and formulas applied to an LSE's forecast should be done equally and consistently to all LSEs; and

4.) CEC discretionary adjustments that do not reflect the approved methodology should be published and thoroughly explained.[36]

5.3.2. Discussion

In D.04-10-035, the Commission adopted load forecast protocols that explicitly called for the CEC to review LSE-submitted load forecasts and to adjust them for plausibility and consistency. This was done largely due to concerns about gaming.

In D.05-10-042, the Commission deferred to the CEC the discretion to determine the exact method by which the average coincident approach would be implemented. In D.12-06-025, the Commission changed the coincident methodology to an LSE-specific methodology without specifying the details of how that methodology would be implemented. The CEC is acting consistently with the Commission's intent in adjusting LSE load forecasts for the purpose of setting RA requirements. However, we do agree with Shell, DACC, and CLECA, that there needs to be more transparency and consistency in the current load forecast adjustment process. Therefore, we adopt Shell's request to improve the current transparency and consistency of the forecast allocation process.

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[36] Shell Energy Comments at 6-7.

Energy Division, with CEC assistance, will publish the following documents following the initial year-ahead allocations around the end of July:

1. The five monthly dates and times of the CAISO system peak used in each LSEs coincident calculation and the five monthly OASIS coincident peaks (used as a proxy for the EMS data);
2. The CEC's step-by-step process for load forecast adjustment; and
3. Any discretionary adjustments made with a detailed explanation of the adjustment and why it was made (this would be narrated with proxy load data).

In addition to publishing the documents listed above, the CEC will apply the same adjustment factors and formulas to all LSEs equally and consistently.

Additionally, we agree with CLECA, DACC, and Shell that there is a need for a workshop on the RA forecast methodology. Specifically, we see a need for a workshop to discuss the coincident adjustments methodology's reliance on historic hourly data. The "historic method" does not align with the best estimate forecast approach. It would be more appropriate to base a coincident adjustment factor on hourly forecasted load data. We believe a workshop would be an excellent place to begin discussing how a "forecast approach" could work in the future. Additionally, this workshop may include a review and discussion of other Independent Systems/Regional Transmission Operator allocation methodologies.

During Phase 2 of this proceeding, Energy Division and the CEC should host a workshop to facilitate a discussion on changing the coincident adjustment methodology from a "historic approach" to a "forecast approach" and to review other Independent Systems/Regional Transmission Operator allocation methodologies.

5.4. Development of a Bulletin Board (Shell)

Shell proposes the development of an electronic bulletin board for the trading of RA capacity since it would provide greater transparency and liquidity to the market, particularly in light of the adoption of the new flexible capacity procurement obligation. In Shell's opinion, at a minimum, the Commission's Phase 1 decision should direct Staff to make a recommendation in Phase 2 for implementation of an electronic bulletin board for RA capacity for the next subsequent (2017) RA compliance period.

5.4.1. Parties' Comments

No other parties provided comments on this proposal.

5.4.2. Discussion

Federal Energy Regulatory Commission Order No. 719 requires each independent system operator to dedicate a portion of its website to allow market participants to post offers to buy or sell power on a long-term basis. In response, the CAISO participates in the Power Contracts Bulletin Board hosted by PJM Interconnection.[37] We are unclear how the bulletin board Shell proposes differs from the existing one. We encourage Shell to delineate problems with the current bulletin board and specific changes needed to improve the system in Phase 2 of this proceeding.

5.5. Allocation of Flexible Capacity Based on Cost Causation (PG&E)

In adopting the Interim Flexible Capacity Requirement Framework in D.14-06-050, the Commission considered adopting a flexible RA requirements allocation methodology based on an LSEs' contributions to the CAISO's monthly

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[37] Available at: https://www.caiso.com/market/Pages/PowerContractsBulletinBoard/Default.aspx.

net-load ramps used to determine the overall flexible RA requirement. This methodology follows cost causation principals for the allocation and would be consistent with the CAISO's FRAC-MOO tariff language.[38] In D.14-06-050, the Commission adopted the load ratio share methodology instead of the cost causation methodology, and stated that this issue would be considered in a subsequent proceeding.[39]

PG&E proposes that the Commission modify the allocation of flexible RA requirements to Commission-jurisdictional LSEs so that the flexible RA requirements are allocated in proportion to the LSEs' contributions to the CAISO's monthly net-load ramps used to determine the overall flexible RA requirement, in order to better reflect cost causation and to align the Commission's and the CAISO's allocation approaches.[40]

On May 1, 2015, the CAISO published its 2016 Final Flexible Capacity Needs Assessment which included the Commission-jurisdictional allocation of those results. The CAISOs allocation methodology is based on the LRA's LSEs' contribution to the system maximum 3 hour net-load ramp. As described in the Final Flexible Needs Assessment for 2016 paper, "the ISO calculated the LSEs under each local regulatory authority's contribution to the flexible capacity needs using the following inputs:

1.) The maximum of the most severe single contingency or 3.5 percent of forecasted peak load for each LRA based on its jurisdictional LSEs' peak load ratio share.

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[38] Feb 10, 2014 Staff proposal on Implementation of the Flexible Capacity Procurement Framework at 4-5.

[39] D.14-06-050 COL 6 at 66.

[40] PG&E Comments, January 16, 2015 at 17-18.

2.) Δ Load – LRA's average contribution to load change during top five daily maximum three-hour net-load ramps within a given month from the previous year x total change in ISO load.

3.) Δ Wind Output – LRA's average percent contribution to changes in wind output during the five greatest forecasted 3-hour net load changes x ISO total change in wind output during the largest 3-hour net load change.

4.) Δ Solar PV – LRA's average percent contribution to changes in solar PV output during the five greatest forecasted 3-hour net load changes x total change in solar PV output during the largest 3-hour net load change.

5.) Δ Solar Thermal – LRA's average percent contribution to changes in solar PV output during the five greatest forecasted 3-hour net load changes x total change in solar thermal output during the largest 3-hour net load change.

These amounts are combined using the equation below to determine the contribution of each LRA, including the CPUC-jurisdictional load serving entities, to the flexible capacity need.

Contribution = Δ Load – Δ Wind Output – Δ Solar PV – Δ Solar Thermal + (3.5% * Expected Peak * Peak Load Ratio Share)" [41]

5.5.1. Parties Comments

CLECA, SDG&E, SCE and ORA all support this proposal. CLECA notes that the proposal has a good cost causation basis.[42] ORA states that "the Commission should use the CAISO FRAC-MOO tariff flexible capacity allocation methodology as a starting point and continue to refine the methodology in

[41] CAISO Final 2016 Flexible Needs Assessment for 2016, May 1, 2016 at 17-18.

[42] CLECA Comments at 5.

subsequent RA proceedings."[43] ORA also requests that "consideration should be given to last year's recommendation by Energy Division that a flexible capacity allocation methodology should account for inflexible base load capacity and consider some form of socialization of renewable integration costs."[44] CLECA opposes ORAs request because they believe there is insufficient record in this proceeding to adopt Energy Division's proposal.[45]

AReM believes that this proposal needs further evaluation before adoption. Specifically, AReM would like to examine whether a flexible capacity true-up would be reasonable and required, and how the new allocation methodology would be applied to CAM resources. AReM requests that the Commission have additional workshops to explore this proposal and its impacts on RA procurement in more detail.[46]

SDG&E argues that AReM's concerns are not significant enough to oppose this proposal. SDG&E suggests that PG&E's proposal be adopted and that the current true-up mechanism be suspended after the year-ahead showings until these two areas of concern are resolved.[47]

5.5.2. Discussion

PG&E's proposal to allocate Flexible RA requirements based on an LSE's contribution to CAISO's net load ramps, used to determine system flexible need, would align the Commission's methodology with the CAISO methodology.

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43 ORA Comments at 7.

44 Ibid.

45 CLECA Reply Comments at 5-6.

46 AReM Comments at 3-4.

47 SDG&E Reply Comments at 6.

Additionally, it does follow cost causation more appropriately than the peak load ratio methodology.

However, Phase 2 of this proceeding will be considering a durable flexible capacity product. It would be more appropriate and effective to address the allocation of flexible capacity requirements in conjunction with or following the development of a durable flexible product. LSEs may request allocations following the CAISO's method of cost causation from Energy Division, and it will be provided for informational purposes, but no change to the allocation of flexible RA allocations is adopted in this decision.

5.6. Modification of Flexible RA Rules for Storage to Include Discharge and Charge (PG&E)

According to PG&E, "under the current flexible RA counting rules, storage resources with a non-zero transition time between charge and discharge can only count their discharge capacity towards their effective flexible capacity (EFC) value, despite the ability of these resources to provide flexibility by charging."[48] To address this issue, PG&E proposes that the Commission modify its RA counting rules for storage "to include the full range of charge and discharge that a storage facility can achieve and sustain over a three hour period, so long as the resource's transition time between the two states is less than 45 minutes."[49] PG&E believes that the proposal will treat all storage resources equally, result in fair valuation of existing and potential storage resources, help with over-procurement, and reduce costs to customers.

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[48] PG&E Workshop Presentation, February 9, 2015, slide 3.

[49] Ibid.

5.6.1. Parties' Comments

ORA, TURN, GPI, and NRG support PG&E's proposal. CAISO opposes this proposal, recommending that the Commission defer consideration for an additional year. ORA "agrees that PG&E's proposal will result in a fair valuation of all existing storage resources" and believes that the Commission should reject CAISO's recommendation for delay, arguing that "the CAISO is already dispatching energy storage resources with transition times to support the grid, so these resources should receive credit for the benefits they are providing starting in 2016."[50] TURN believes that PG&E's proposal "would recognize the flexibility that such resources – particularly pumped storage – have long provided the system and can be expected to continue providing the system, and should be adopted."[51] GPI supports PG&E's proposal, arguing that requiring resources to transition continuously between charge and discharge is an unnecessary and unproductive restriction. NRG argues that "there is no reason to not allow a storage resource that can transition from full charging (or pumping) to full discharge (or generation) within a three-hour period to count the sum of its charging and discharging capacity towards its EFC as long as flexibility requirements are based on a three-hour period."[52]

In contrast, the CAISO believes that PG&E's proposal to allow a 45 minute transition time between charging and discharging for energy storage resources "cannot be implemented under the CAISO's existing modeling design, and the Commission should defer considering this issue until the CAISO has the

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50 ORA Comments at 5.

51 TURN Comments at 3.

52 NRG Comments at 9.

necessary market product and software in place to optimize energy storage resources with non-zero transition times that are providing flexible capacity. The CAISO could address this issue in a review of the non-generation resources (NGR) model the CAISO is considering this year as part of a broader effort to enhance the participation of energy storage resources in the CAISO markets."[53]

5.6.2. Discussion

As noted in last year's decision, we believe that PG&E's proposal to modify flexible RA rules for storage has merit. Given that storage resources with non-zero transition times are capable of addressing the three hour ramp, just as other storage resources that move from charging to discharging, we agree that the discharge portion of these resources should be counted in the EFC. The CAISO does not argue that pumped storage fails to address the net load ramp contribute, only that the CAISO is currently unable to dispatch these types of resources at the current time. We are unpersuaded that this is sufficient grounds for delay. Therefore, we will modify our EFC counting rules, contained in D.14-06-050, Appendix B, to eliminate the prohibition on non-zero transition times, and to allow up to 45 minutes transition times that will not count towards either the one-and-a-half hour charge or discharge.

5.7. Changing the Local True-Up Timeline (AReM)

In response to the partial re-opening of direct access markets in 2010, the Commission adopted a local true-up process in D.10-12-038. This true-up process reallocated local RA obligations twice throughout the compliance year (in two cycles) after the original year-ahead local allocations. The first true-up

[53] CAISO Comments at 2-3.

allocation covered May and June and the second allocation covered July-December. In last year's RA decision, D.14-10-050, the Commission modified the original process to include only the second allocation period from July-December. This change was made to remove unnecessary complexity.

This adopted change is being implemented for the first time in the 2015 RA compliance year. As a result, AReM anticipates inefficiencies, and possibly uncompensated costs. Specifically, because the local RA true-up process falls late in the annual RA procurement cycle, AReM claims LSEs have extremely limited time to procure additional RA (if they are gaining load) or to sell off excess RA (if they are losing load), before submitting the month-ahead RA filing for the peak RA month in August. LSEs submit their load forecasts for the August RA compliance month in mid-May. AReM claims this timing creates inefficiencies and adds unnecessary costs for LSEs if they are unable to sell off RA they procured but no longer need to meet their peak system RA requirements for August or must scramble to procure last minute RA at higher prices to meet their revised August RA peak system RA requirement. Significant quantities of load can and do migrate among LSEs, particularly ESPs, causing the potential cost burden associated with this timing change to likely fall disproportionately on the ESPs.

AReM proposes moving the filing deadline for the load forecast and true-up filing one month earlier in the year – to the may load forecast month. LSEs would be required to submit their RA compliance filings for the May load forecast month in mid-February each year. AReM believes that this simple modification will reduce the potential for inefficiencies related to RA procurement to address true-ups from migrating load.

The table below shows the timing of the filings required under AReM's proposal compared to the timing of the filings under the current process pursuant to D.14-06-050.

Current and Proposed Timing for Local RA True-Up

Filing	D.14-06-050 as Implemented by Energy Division	Proposed
LSEs submit revised August load forecast for Local RA True-Up	Mid-March	Mid-February
LSEs submit first RA compliance filing using adjusted Local RA True-Ups	Mid-May for July RA compliance month	Mid-April for June RA compliance month

5.7.1. Parties' Comments

CLECA supports AReM's proposal that LSEs submit their first RA compliance filings using adjusted local RA true-ups in mid-February rather than mid-May, as it will allow the bilateral market to operate more efficiently.[54]

PG&E opposes AReM's proposal because if AReM's proposal were adopted, the local true-up would not function effectively as a true-up. Under this proposal, the true-up would be based upon customer data from January which is too early in the compliance year. Since the local true-up process was just changed in June 2014, PG&E recommends that some additional experience be gained with the local RA true-up before it is modified again.[55]

5.7.2. Discussion

The order from D.14-06-050 for one incremental local true-up allocation, to adjust Local RA obligations from July compliance through December is in the process of being implemented for the 2015 RA compliance year. We agree with PG&E that some additional experiences should be gained from the most recently adopted change, before the process is modified again. We will not adopt AReM's proposal for 2016.

5.8. Capping Local RA Requirements at System RA Requirement (CAISO)

The CAISO proposes that an LSE's local capacity requirement be capped at that LSE's system requirement in the monthly resource adequacy process. The purpose of this proposal is to address the situation where, during some months of the year, a LSE may be required to demonstrate local capacity in excess of its

[54] CLECA Comments at 7.

[55] PG&E Comments at 4-5.

total system monthly peak demand and reserve margin. This will not impact the current local capacity technical study methodology used to determine the LSE local capacity requirements each year.

The CAISO notes the cap should not apply to the annual showings for two reasons. First, the system requirement is always greater than the LSE's local requirement for summer months. Second, because there is no annual system showing requirement for non-summer months, there would be no system requirement against which to compare the local requirement in those months. This approach is consistent with the CAISO's proposal in the Reliability Service initiative to facilitate new substitution and replacement rules.

5.8.1. Parties' Comments

SDG&E and TURN support the CAISO's proposal. SDG&E believes the adoption of this change will protect utility ratepayers and prevent subsidization of other LSEs. This issue is of particular concern to SDG&E given its geographic location. Because its service area is located in a load pocket, SDG&E's local RA requirement is higher than its system RA requirement during certain months of the year. If SDG&E is required to meet local RA requirements that exceed its system RA requirements, other LSEs' resources will be able to lean on SDG&E's surplus capacity at ratepayers' expense. While SDG&E supports the CAISO's proposed cap, it believes that the cap should be effective only during the month-ahead time frame.[56]

TURN also support the CAISO's proposal. TURN observes, however, that it seems more equitable for the benefits of this policy to be provided to all LSEs serving load within such an LCR. That is, the Commission should consider reducing the combined monthly LCR obligations of all LSEs within an LRA when that LRA's total monthly system RA requirement falls below the LRA's annual LCR. TURN believes further analysis of the differences in monthly system RA requirements and annual LCRs in San Diego is appropriate to assess the significance of this issue and whether such action should be taken. However, if such analysis cannot be performed before June, the expected time of the next RA decision, the Commission should implement the CAISO's proposal for the 2016 RA compliance year.[57]

PG&E, SCE, ORA, IEP, Calpine, and NRG oppose the CAISO's proposal. Calpine opposes the CAISO's proposal because it potentially undermines local reliability reductions in local RA requirements are allocated across multiple Local Capacity Areas (LCAs) within one Transmission Access Charge (TAC) area. Calpine argues that the CAISO's proposal is particularly problematic in TAC areas where there are multiple LCAs. The CAISO's proposal appears to allow an LSE to reduce its local RA requirement in any LCA to the extent that the sum of its local RA requirement exceeds its system RA requirement. If the CAISO proposal was implemented, and local RA requirements were reduced disproportionately in a particular LCA, RA capacity could be reduced and reliability degraded significantly in the LCA.[58]

PG&E, SCE, and ORA are concerned that the CAISO's proposal unfairly relaxes local RA requirements for some LSEs and not others, leading to unequal treatment of LSEs. IEP is unable to support this proposal until it is more

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[56] SDG&E Comments at 4-7.

[57] TURN Comments at 4-5.

[58] Calpine Comments at 1-2.

confident that it understands the details and implications of this proposal. IEP argues that the CAISO has failed to make the case that local reliability requirements can be relaxed without creating adverse effects or increased risks for the grid.[59] NRG is also unable to support the CAISO's proposal at this time since implications of the CAISO's proposal with regards to the year-ahead local capacity procurement or showings are not clear and NRG sees the potential for both positive and negative impacts on the monthly local capacity showings.[60]

5.8.2. Discussion

We adopt the CAISO's proposal to cap local RA requirement at monthly system RA requirements. Although this is an SDG&E-specific issue where in the winter months, the local RA requirement exceeds system RA requirement, adopting it will prevent SDG&E from contracting excess local resources.

This proposal compels us to examine the local RA requirement based on the August peak demand and imposed on LSEs for the entire year. The local RA requirement is higher than needed for non-summer months. Therefore, we request that the CAISO consider monthly or seasonal local requirements.

5.9. Unbundling Flexible Capacity from System Capacity for all Non-CAM Resources (SDG&E)

In D.14-06-050, the Commission deferred consideration of SDG&E's proposal regarding unbundling of system and flexible capacity. SDG&E proposed that generic and flexible capacity be unbundled such that "the same megawatt could count as a flexible megawatt in one LSE's portfolio and as an

[59] IEP Comments at 1-3.

[60] NRG Comments at 10-12.

inflexible megawatt in another" LSE's portfolio. SDG&E continues to strongly support the proposal to unbundle generic and flexible capacity attributes and proposes that the Commission adopt SDG&E's unbundling proposal for the 2016 compliance year.

SDG&E believes that bundling places an unnecessary and onerous burden on contracting parties and fosters market inefficiency. Moreover, while it is theoretically possible to contract around these burdens in the year-ahead time frame, the increased delay and complexity associated with curing flexible-capacity deficiencies under the bundling framework is unworkable in the month-ahead and real-time context. This fact needlessly exposes ratepayers to increased replacement costs and non-availability penalties arising from uncured or incurable planned and forced outages of flexible resources in the RA portfolios of Commission-jurisdictional LSEs. SDG&E believes that the inefficiencies resulting from the bundling rule cannot be justified in the absence of substantial evidence that bundling mitigates any market power concerns and that the adoption of SDG&E's unbundling proposal will not undermine system reliability or lead to over-procurement.

5.9.1. Parties' Comments

TURN and ORA agree that unbundling will likely reduce overall costs while posing no threat to reliability.[61] The CAISO opines that modifications to the CAM construct may be required to allow the separation of system/local and flexible capacity for CAM resources. The CAISO encourages the Commission to make those changes so that LSEs, and both non-CAM and CAM resources, can capture the benefits that would come from buying and selling flexible capacity independently from local/system RA capacity. However, the Commission should allow unbundling for only non-CAM resources in this proceeding.[62]

IEP, WPTF, and NRG argue that unbundling will lead to more efficient markets. Shell and CESA also agree with SDG&E's statement that "requiring bundling in every instance promotes overprocurement, artificially constrains the market for flexibility, and potentially exposes incremental capacity to SCP penalties."[63] The Joint DR Parties believe SDG&E has offered a reasonable approach to allow all resources to unbundle and trade these attributes separately. However, if the Commission does not desire to unbundle the EFC and NQC for all resources, the Joint DR parties argue it should be done for demand response and storage.[64] GPI supports unbundling of flexible and conventional RA capacity because the two products are truly separate and mutually independent.[65]

PG&E and SCE oppose SDG&E's proposal. PG&E argues that if the proposal is adopted, it has the potential to increase the administrative burden associated with RA compliance and tracking and raises the potential for contract disputes regarding how unbundling would affect parties' contractual rights to the flexible and/or generic attributes under existing contracts. PG&E also does not perceive a clear need for such unbundling. As was discussed during the February 9th workshop, existing transactional mechanisms enable LSEs to

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[61] ORA Comments at 12-13; TURN Comments at 4.

[62] CAISO Comments at 4-6.

[63] SDG&E Presentation at February 9, 2015 Workshop at 7.

[64] Joint DR Parties Comments at 4.

[65] GPI Comments at 1-2.

"balance out" their RA portfolios if one LSE has an overabundance of generic RA resources and an insufficient amount of flexible RA resources, while another LSE has a countervailing RA position.[66] SCE supports comments made by PG&E that oppose SDG&E's proposal to unbundle flexible and generic capacity from RA resources.[67]

AReM is concerned about potential unintended consequences of this proposal and believes that more discussion is required. If SDG&E indeed proposes to limit its unbundling proposal to non-CAM resources, then the question must be addressed as to why the unbundling is appropriate only for non-CAM resources, and whether the IOUs can unilaterally determine which RA resources to "unbundle."[68] CLECA believes the Commission should review the perceived constraint to unbundling EFC from NQC for CAM resources and determine whether it can and should be changed in this proceeding to facilitate that unbundling. Such unbundling could allow certain resources, like demand response, to more readily provide flexibility.[69]

5.9.2. Discussion

While we acknowledge that there are potential efficiency gains from unbundling flexible capacity from system capacity, there remains significant uncertainty and potential for negative impacts. Accordingly, we will again defer this issue, and consider it for the 2017 compliance year or in conjunction with consideration of a more durable flexible product.

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66 PG&E Comments at 8.

67 SCE Reply Comments at 4.

68 AReM Comments at 4-5.

69 CLECA Reply Comments at 4-5.

5.10 Unbundling Flexible Capacity for Demand Response and Storage (Joint DR Parties)

The Joint DR Parties propose unbundling the EFC from the NQC of storage and demand response resources because this would allow these resources to claim either their full EFC without limit of NQC or to allow a resource to capture its highest usage value by participating in RA with either an NQC or EFC. To be a combined flexible and system/local RA resource would, in some months, require a resource to be available for more than 10 hours/day which is something that a DR resource was not designed to do. Since a DR resource can provide ramping services or peak reliability, but very few customers would be willing or able to participate in a program that required such a broad level of curtailment so as to provide both, the Joint DR Parties believe that it would be a much better use of this high loading-order resource to unbundle these requirements and allow a DR resource to either meet RA MOO or EFC MOO, whichever the customer (or aggregation of customers), is most appropriate for providing.

Additionally, the Joint DR Parties propose that Commission hold a workshop to address DR performance and measurement protocols.

5.10.1. Parties' Comments

CLECA supports the Joint DR Parties' proposal since it could allow the use of more preferred resources for flexibility, which would be beneficial.[70] CLECA also supports the Joint DR Parties' proposal for a workshop to address the DR performance and measurement protocols that were adopted, at least

[70] CLECA Comments at 3.

conceptually, in the last RA proceeding. CLECA would find additional clarity regarding these protocols to be useful.[71]

The CAISO does not oppose consideration of the SCE, CESA, or the Joint DR Parties unbundling proposals at a later time. However, the CAISO contends the proposals are not ripe for consideration at this time as their impacts are uncertain, and they require further study. CAISO agrees with SCE that its proposal would require "modifying the EFC process to require a resource to be deliverable in order to qualify for an EFC."[72]

5.10.2. Discussion

While we acknowledge that there are potential benefits to unbundling EFC from NQC including additional utilization of preferred resources such as storage, there remains significant uncertainty regarding its impacts. We will not adopt it for the 2016 compliance year, but will again address this issue in Phase 2 or Phase 3 of this proceeding. Additionally, DR topics, including a potential workshop on DR performance and measurement protocols will be addressed in Phase 3 of this proceeding.

5.11. No NQC Required to Get an EFC (SCE)

SCE proposes that the Commission should eliminate the current requirement that resources need an NQC before they can receive an EFC. SCE believes that under a process that properly establishes an EFC, there are no benefits to having resources qualify for NQC in order to be eligible for EFC. SCE notes that certain types of resources can be configured to serve peak load needs,

[71] CLECA Reply Comments at 6.

[72] CAISO Comments at 6-7.

ramping needs, or both, and that requiring a resource to qualify for NQC before being able to receive EFC may result in a flexible resource being configured in a way that does not optimize their value or attributes. SCE concludes that allowing the flexibility to configure these resources in a manner that is the most cost effective will increase the availability of these products to the market and result in reduced costs to customers.

In response to objections by other parties, SCE recognizes that the current EFC process does not account for deliverability and supports modifying the EFC process to require that a resource be deliverable in order to obtain an EFC.

5.11.1. Parties' Comments

CLECA shares the concern expressed by SCE regarding the disconnect between the 3-hour period required for providing flexible RA and the 4-hour requirement for NQC for system and local RA, since an RA resource could provide flexibility without meeting the NQC requirements. CLECA notes that if a DR or storage resource were to be available for three hours for flexibility, as required, it would get an NQC of zero because it would not be available for the fourth hour required for system and local RA. CLECA believes this proposal would create greater opportunities for resources to provide flexibility.

PG&E generally supports SCE's proposal to remove the requirement that a resource qualify for an NQC level for generic RA to be eligible to provide EFC for flexible RA. If a resource has the capability to meet the requirements for flexible RA, then it should be allowed, in PG&E's view, to choose to provide flexible RA but not generic RA. From PG&E's perspective, this option should be provided to all resources, not just a limited subset such as DR resources. PG&E believes that a resource should not be allowed to unbundle flexible and generic RA attributes, but that resources should be able to choose to provide only generic or only flexible RA, if it is able to satisfy the applicable requirements for the type of RA it wishes to provide. If, however, it wishes to and is able to provide both generic and flexible RA at the same time, then both of those attributes must be provided to the same LSE.

CESA agrees with SCE that a resource's EFC should not be limited by its NQC. CESA notes that flexibility is a separate resource attribute which is wholly distinct from peak summer dispatch. Since the need for flexibility is projected to be highest during spring, fall, and winter, CESA believes that requiring the EFC of all resources to be limited by a capacity metric (NQC) that is based on summer peak may needlessly increase the cost and interconnection requirements for these resources and discount the value of flexibility, without any corresponding increase in system reliability.

CAISO, ORA, and AReM oppose the proposal. CAISO notes that SCE's proposal would allow a resource to be a flexible-only capacity resource. This implies that the resource would not be subject to the CAISO's deliverability study that is required to obtain an NQC value, and the resource would not be required to be deliverable during peak hours. The CAISO does not oppose consideration of these proposals at a later time, noting that their impacts are uncertain, and they require further study. The CAISO believes the details of implementing the SCE proposal must be dealt with in the CAISO annual cluster study process which will assess the impact that the change would have on resource deliverability and system reliability.

ORA notes that separating EFC requirements from the NQC requirements would potentially allow for some resources to provide flexible capacity while not meeting requirements to provide peak power, resulting in more resources qualifying to provide flexible capacity and allowing IOUs to procure EFC products to meet ramping needs in a more cost-effective manner. However, while ORA generally supports the elimination of the NQC requirement for EFC qualification, ORA does not believe there is currently sufficient data or analysis to recommend adoption of the proposal in this year's RA proceeding. AReM requests that SCE provide additional information regarding how this proposal would affect available RA resources and their current RA values.

5.11.2. Discussion

We acknowledge that there are a number of outstanding issues regarding resource qualifications for NQC and EFC status, including the important issues of deliverability and how this proposal would affect available RA resources. Given the multiple complexities of this proposal, and given that the flexible capacity product may change in the future, we will defer consideration of this issue.

5.12. Two Hour Maximum Cumulative Capacity Bucket (SCE)

D.05-10-042 discussed the importance of ensuring that sufficient resources would be available to meet the peak need without requiring all resources to be physically capable or contractually obligated to deliver energy at all hours. This decision led to the creation of maximum cumulative capacity (MCC) buckets to avoid overreliance on resources that were not contractually or operationally available in all hours of the month. However, the grid's needs have shifted from peak needs to ramping needs, and SCE proposes that creation of a new MCC bucket for resources which could only provide power for a period of two hours would alleviate this need for ramping capacity.

Currently, MCC buckets are comprised of 5 categories, all of which must be dispatchable for at least 4 continuous hours. SCE asserts that the creation of a 2-hour bucket will increase reliability during periods of highest need and permit the inclusion of additional technology types that would not be able to provide four hours of continuous energy, such as certain types of energy storage (ES) and DR. This change would reduce customer cost by allowing lower cost options into the market, because certain resources could provide 2-hour energy at a lower cost than if they were required to provide 4-hour energy.

SCE, in its reply comments, grants that studies need to be performed to determine the appropriate quantity limit placed on this MCC bucket. However, SCE contends this study should not be dependent, as CAISO suggests, on the Storage Roadmap process, because that process fails to view the 2-hour resource MCC bucket as applicable to all resources (including DR), and instead would analyze it purely as energy storage. SCE prefers supporting studies to be completed in the near future in order to support the development of these projects and is concerned that, if studies are delayed, resources being developed now and in the future will not be able to adjust their capabilities to best fit the needs of the system.

5.12.1. Parties' Comments

CLECA and SolarCity approve of the 2-hour MCC bucket proposal. CLECA notes that a 2-hour MCC bucket would allow for greater participation of demand response and storage resources, which is a policy goal of the Commission. Essentially, the two-hour resources would have the same 24-hour per month must-offer obligation currently in effect, but a use limitation of two hours, rather than four. CLECA further notes that the CAISO's concerns about the uncertainty of peak hours and how these resources would apply to local RA requirements, discussed below, could be addressed by limiting the total amount of resources in such a 2-hour bucket.

SolarCity agrees with SCE that this proposal would facilitate the inclusion of additional technology types that do not always lend themselves to providing a longer duration of energy, such as ES and DR. The removal of barriers for new technology types is an appropriate policy goal, because these new technologies are capable of providing reliability value to California's grid. Solar City further maintains that while this expansion will reduce customer cost by allowing lower cost options into the market, procurement will need to be more precisely attuned to system needs to procure least-cost RA while maintaining system reliability. SolarCity also endorses SCE's proposed methodology to determine the size of the 2-hour MCC bucket, which SolarCity calls conservative and reasonable.

ORA, CAISO, PG&E, SDG&E, IEP, NRG, and WPTF oppose the creation of a 2-hour MCC bucket. ORA believes this proposal has merit, but is premature at this time for two reasons. First, the current MCC buckets are defined by availability per month, and not by minimum dispatch time. Second, ORA believes that ramping needs would be better served by a 3-hour MCC bucket, which would also align with SCE's proposal to eliminate the NQC requirement for EFC qualification (see Section 6.11). This approach, according to ORA, would shift the burden of meeting the existing 4-hour dispatch requirement to bidders and would decrease the CAISO's burden of coordinating dispatch.

The CAISO agrees that 2-hour resources may contribute to reliability during the highest peak hours in certain instances and in certain areas. However, there currently is no data or operational experience to assess the reliability benefits and impacts of these resources. Before creating an MCC bucket dedicated to two-hour resources, the CAISO believes that additional analysis must be conducted to determine how to measure and utilize two-hour resources to enhance reliability and identify what quantity of capacity from these resources can be accommodated without degrading reliability. The CAISO expects to develop the necessary data regarding the reliability benefits of those resources as part of its energy storage roadmap efforts and its primary work on developing the durable flexible capacity product. The CAISO maintains that this work is necessary to properly assess SCE's proposal.

PG&E also opposes the two-hour MCC bucket at this time because there has not been sufficient analysis to determine whether it might compromise system reliability. PG&E further believes the Commission should not relax eligibility standards for a defined product simply to accommodate individual technologies or resources without prior careful evaluation of the effect they would have on system reliability. PG&E endorses the CAISO's warnings regarding the lack of studies or assessments and believes any action in advance of those studies would be premature.

SDG&E suggests that it is not necessary to develop a 2-hour MCC bucket since MCC Bucket 1 is able to accommodate the resources described by SCE. However, SDG&E cautions that the proposal needs to be deemed feasible by the CAISO and vetted by stakeholders before it is considered for adoption. NRG and IEP also believe more studies are required, while WPTF stated that they are also opposed to the 2-hour bucket proposal.

5.12.2. Discussion

This proposal and other related proposals cast legitimate doubt upon the efficacy and utility of the MCC bucket apparatus, which was constructed for different conditions and needs than those faced by the grid today. A full review of the MCC buckets may be warranted in the near future. This proposal, however, is not sufficiently analyzed for adoption at this time. SCE concedes that additional studies are necessary in order to understand the appropriate quantity limit placed on this MCC bucket. Further, valid concerns have been raised with respect to whether this proposal would affect system reliability by the CAISO and others. Thus, we believe that this issue requires further study in Phase 2 to address the capacities of ES and DR, and the grid's need for reliability and additional flexibility prior to adoption.

5.13. Storage Parties Proposals/Clarifications (CESA)

CESA outlined several areas where it believes additional RA guidance or revisions are needed in order to better incorporate behind-the-meter distributed energy storage resources. According to CESA, there are currently major barriers to distributed energy storage resources located behind-the-meter because the supply side DR resource category has yet to be fully defined by the Commission. Implementation considerations concerning supply side DR resources effectively preclude procurement of these resources, specifically including appropriate qualification for participation as flexible RA. In addition, harmonization is needed between the NGR and Proxy Demand Response (PDR) product categories currently in use at the CAISO. Today's PDR rules only allow distributed aggregated resources to count their load modifying capability, rather than their full flexible capacity. NGR rules, on the other hand, allow for resources to count their full flexible capacity, but do not yet fully accommodate aggregation. Filling these gaps is critical to allow behind-the-meter resources to participate in DR and be appropriately valued in RA.

CESA supports NGR registration for energy storage resources in many cases. However, NGR registration should not be a requirement to qualify as flexible RA. For example, there may be circumstances in which it is preferable to allow a behind-the-meter resource to participate as part of an end use customer's overall energy management scheme. The resource might then qualify for flexible

RA in a DR category. Depending upon future changes to ELCC and EFC methodology, an energy storage resource may also better qualify for flexible RA in combination with a traditional or renewable generator rather than as an NGR.

Currently, behind-the-meter storage is at a disadvantage when attempting to provide RA in California. The $50,000 deliverability study fee renders the economics of small projects non-viable, and should be therefore adjusted for their size. The need for site certainty also stymies aggregators, who would prefer to develop projects across a given electrical area and may not have addresses available at the time of the study. Allowing regional studies would address this concern. An additional problem is when variable energy resources (VERs) add ES, and must be re-studied, moving the VER+ES to the end of the line, resulting in a less-favorable queue position and, therefore, additional transmission upgrade costs. Thus, adding ES to a VER is discouraged under the current rules.

Additionally, CESA recommends that there be two options for the NQC methodology for BTM storage resources registered as PDR:

1) In cases where the energy storage resource is an integrated component of a DR scheme that may include building controls and behavioral change, the NQC should be based upon the current 10-in-10 baseline methodology.
2) Alternatively, behind-the-meter energy storage resources should be allowed to participate as PDR/NGRs, in which case the NQC and EFC should be based upon metered performance and testing.

CESA also requests Commission support for adoption of streamlined metering and telemetry rules and equipment. The CAISO's "Expanding Metering and Telemetry Options" initiative has begun addressing these requirements.

5.13.1. Parties' Comments

SolarCity agrees with CESA that additional RA guidance is needed for behind-the meter resources that have the capability to provide far more benefit to the grid than traditional demand response assets. SolarCity's understanding is that behind-the-meter resources are currently eligible to participate in the RA program as part of a demand response offering. While this mechanism provides a vehicle for dispatchable behind-the-meter storage to provide reliability to California's grid, it also requires owners of behind-the-meter resources to take on the risk of managing load in order to access the market. For example, a commercial or industrial customer with a large battery on-site today would have to manage the risk of managing and dispatching load in order to derive RA value from the battery via a demand response program. While many owners of behind-the-meter storage systems may be willing to provide performance guarantees for their storage systems in exchange for RA value, fewer will be willing to provide performance guarantees for their net-load, due to the uncertainty of load relative to storage performance.

While requiring all behind-the-meter resources to be managed as a single load is simpler for distribution and market operators, SolarCity notes that treating behind-the-meter storage as a DR resource will inhibit the participation of aggregated behind-the-meter storage, due to the load management risks discussed above and inability to benefit from the DR resource's ability to charge and discharge nearly instantaneously in response to a signal from a market operator in this framework. This treatment also currently prevents behind-the-meter storage from explicitly providing downwardly flexible capacity as part of the resource's charging state. SolarCity recommends that CPUC staff begin to define the longer-term vision of the role aggregated behind-the-meter storage should play in RA. It may be appropriate to enhance RA rules to incorporate dispatchable behind-the-meter resources into the RA program as actual generation (or non-generation resources, in the case of storage), rather than trying to fit these resources into the demand response box.

SolarCity understands that some of the technical limitations of behind-the-meter resources, such as metering, are being addressed through the CAISO Expanding Metering and Telemetry Options stakeholder process, and will also be addressed in upcoming storage stakeholder processes following the recently released Energy Storage Roadmap and recommends tying these CAISO stakeholder processes to the Commission's longer term vision regarding the role aggregated behind-the-meter storage should play in providing grid benefits. This will be important to determining how these resources can be best used to meet the state's RA needs.

GPI supposes CESA's proposal that storage resources that are associated with and operationally integrated with renewable generators, such as thermal storage at solar thermal generation facilities, should have RA values assigned based on an ELCC analysis of the total facility (generator plus storage) and that the RA values for renewables with associated storage systems should be based on the integrated unit's ability to provide RA capacity, including flexible and/or conventional.

5.13.2. Discussion

We acknowledge that there are a number of outstanding issues regarding treatment of storage resources. While this is not the forum for addressing CAISO issues such as the PDR/NGR product categories and the Expanding Metering and Telemetry Options stakeholder process, we agree that it is important to begin to better define the role of aggregated behind-the-meter storage and storage resources that are integrated with renewable generation. To this end, we encourage parties to submit specific proposals regarding treatment of storage resource in Phase 2 of this proceeding.

6. SCE/SDG&E DRAM Motion

In an April 20, 2015 motion, SCE and SDG&E moved for an order permitting the MW contract quantities obtained through the Demand Response Auction Mechanism (DRAM) Pilot for 2016 to be (i) used to determine the QC; and (ii) exempted from the Load Impact Protocol requirement as specified D.14-06-050.

According to SCE and SDG&E, the DRAM working group has determined that the system RA obtained under the 2016 DRAM Pilot contracts will not be able to meet the deadlines to count for annual RA for 2016 since contracts with third party providers will not be finalized until early March 2016 according to the planned schedule. However, the working group believes that the RA obtained in the 2016 DRAM Pilot should be allowed to qualify for system RA in the monthly filings since the stakeholders' proposed DRAM design has focused on ensuring that the contracted MWs would perform in accordance with Commission RA counting requirements, and that the DRAM winners would be able to follow the CAISO's MOO rules, as required.

In D.14-06-050, the Commission adopted, on an interim basis, the existing load impact protocols (LIPs) as the basis for determining the QC and EFC of supply-side DR. In addition, Appendix B of that decision, states that regarding the rules for testing and verification for supply-side DR, "QC and EFC determinations shall incorporate historical performance data where possible. To the extent that historical performance data is not available or appropriate, the program design and/or test data may be used."

Since the DR auction will not occur until late 2015 and historical performance data will therefore not be available at the time the contracts are executed, particularly for summer months, SCE and SDG&E propose to exempt DRAM Pilot resources from the requirement for load impact protocols for 2016. The proposed QC methodology would only base the QC on the program design so that the monthly QC is equal to the monthly Contract Quantity of the resources that make up the contract without the requirement to utilize load impact protocols. This proposal is limited in scope for newly established Supply-Side DR as a result of the DRAM Pilot for the 2016 compliance year. Any test or dispatch results may still be used for QC determination by Commission staff for the following compliance year, if applicable.

D.14-12-024, which approved the DRAM Pilot, requires that all customers share the cost of the DRAM Pilot since all customers are eligible to participate in it. The decision does not, however, address the question of how the RA credit for the DRAM Pilot should be allocated. Since the DRAM Pilot contracts are not expected to be signed until December 2015, which is too late for inclusion in the standard DR allocation process in which ED staff sends initial DR allocations to all LSEs in July and final allocations in September, SCE and SGE&E propose a separate DR allocation true-up process for DRAM for the 2016 and 2017 compliance years.

Under the proposal, Energy Division staff would allocate the respective contract quantities to the respective LSEs for the entire term of the contract beginning with the earliest reasonable showing month within five business days after DRAM contracts are approved by the Commission. This allocation method would be based on load share, as established in D.09-06-028. For 2016, DRAM capacity would only provide System RA credit. For Commission-jurisdictional non-IOU LSEs, each LSE would receive a credit very similar to its DR allocation credit. The IOUs would receive a negative DR credit equal to the sum of the respective LSEs' credits who serve load in the IOU's territory. On each monthly compliance showing, the IOUs must show each DRAM Resource ID and the applicable NQC or contract quantity, whichever is lower.

6.1. Parties' Comments

PG&E agrees that the contracts in the DRAM Pilot program should receive appropriate RA credit and that the RA value of the contracts should be appropriately allocated to the benefit of all customers, since all customers share the cost of the DRAM Pilot. PG&E also agrees that the RA value of the DRAM Pilot contracts for 2016 should be based on their program design as was authorized by D.14-06-050 and that the RA value of the DRAM Pilot contracts should be allocated to all Commission-jurisdictional LSEs using the demand response RA allocation method adopted in D.09-06-028. However, in PG&E's view, since both basing the RA value of the DRAM contracts on program design and allocating the RA value of contracts to Commission-jurisdictional LSEs have been approved in previous decisions, no change is needed to the RA program. PG&E suggests that the Commission confirm this treatment for the DRAM Pilot contracts when it acts on the April 20, 2015, Tier 3 Advice Letter (AL) by the three utilities setting forth the DRAM Pilot design, requirements, protocols, pro forma contracts evaluation criteria, and non-binding cost estimates.

The Joint DR Parties support using contracted amounts to determine RA values for DRAM Pilot contracts since historical performance data will not be available. Additionally, while the DR Parties find it reasonable to exempt the IOUs from LIPs for the 2016 DRAM Pilot, they also feel that the same timing issues that make adherence to the protocols difficult for IOUs applies equally to successful bidders into the 2016 DRAM Pilot and that bidders should also be exempted from performing load impact analysis for 2016. According to the DR Parties, AL 3208-E, et al., make it clear that this exemption is intended to apply to the successful bidders ("Sellers") as well as IOUs. The DR Parties request that the Commission make clear that load impact analysis is not required and should not be imposed as a contract obligation on either the Sellers or Buyers of DR for the 2016 or 2017 DRAM Pilots. Rather, QC for the Buyers would be based on contract capacity and the QC for Sellers will be Demonstrated Capacity, as defined in the Standard Contract attached to AL 3208-E, et al., with a modification of that contract to confirm the exemption from using load impact protocols applies to both Seller and Buy in the DRAM Pilot.

ORA requests that the Motion be held pending resolution of the DRAM AL since in resolving the AL, the Commission could approve changes to the DRAM proposal that could impact the issues raised in the Motion. ORA has concerns that DR aggregators typically overestimate the amount of DR they can actually provide and that this is likely to occur for the DRAM bids aggregators submit. Therefore, it would not be prudent to establish RA Qualifying Capacities on such a speculative number. Also, if DRAM bid winners are allowed to request lower QC after contracts are signed, as requested in the Motion, this would provide a perverse incentive for DR aggregators to overestimate the DR capacity to bid into the DRAM in order to win a bid with no consequences for requesting a lower QC value later on. ORA believes that this issue would be best addressed in the AL and since the outcome of the AL could affect issues covered in this Motion, the Motion should be held pending its resolution.

6.2. Discussion

We appreciate that the DRAM Pilot is an important step forward in terms of integrating supply-side DR into the CAISO market and, as this is a new program expected to begin in June 2016, there is not historical performance data available on which to base QC calculations.

We believe the current supply-side DR WC rules are based on the LIPs, even if there s no historical performance history available. We understand that DRAM timelines would not allow for LIPs to be submitted for 2016 DR RA value since DRAM auction has not taken place. Providing DRAM contracts with an RA tag is an essential part of the DRAM to its success. Since there is currently no LIPs available for future DRAM contracts, we believe that if is necessary to accommodate SCE and SDG&E's motion DR to allow for the use of program design, in this case contracted MWs, rather than load impact protocols for the 2016 DRAM Pilot. This ruling applies only to newly established Supply-Side DR as a result of the DRAM Pilot for the 2016 compliance year. If needed, issues surrounding the 2017 compliance may be addressed in future decisions.

In allowing the use of program design rather than load impact protocols to determine RA values for year one of the DRAM pilot, we are in effect exempting both the IOU "Buyers" of DR and the DR aggregator "Sellers" of DR from the LIPs for 2016. Any requirement in the DRAM contract requiring Sellers to provide LIPs to the Buyers should be removed for the 2016 compliance year. The DRAM contract also contains provisions penalizing the Seller if they fail to deliver contracted MWs. Implementation details will be covered when the Commission acts on the April 20, 2015, Tier 3 AL.

Additionally, since the DRAM Pilot was designed specifically to enable contracted resources to receive RA credit, we acknowledge that system RA credit should be available for the 2016 Pilot. While the planned contracting schedules will not allow for the program to count for annual RA for 2016, we agree that RA obtained in the 2016 DRAM Pilot should be allowed to qualify for system RA in the monthly filings from the June to December 2016 period during which the program will be active.

As established in D.09-06-028, all benefits of the pilot should be allocated equitably across LSEs based on load share. Since the timing of the DRAM Pilot will prohibit participation in the standard DR allocation process, we find that the proposed allocation process is reasonable for the 2016 compliance year.

7. Comments on Proposed Decision

The proposed decision of the Administrative Law Judge 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 15, 2015 by AReM, the CAISO, Calpine, CAC, CLECA, DACC, GPI, IEP, MCE, NRG, PG&E, SCE, SDG&E, Shell Energy, SolarCity, and WPTF. Reply comments were filed on June 22, 2015.

The proposed decision was modified as follows:

- A new sub-Ordering Paragraph 5D was added regarding creation of proxy data for the calculation of Qualifying Capacity for non-dispatchable resources for 2016, which was discussed in the text of the proposed decision but inadvertently left out of Ordering Paragraph 5;
- Section 4.2.3 was modified based on the CAISO's comments to clarify issues related to definition of dispatchability for Qualifying Capacity calculations and a new Ordering Paragraph 5E was added on this point;

- A number of typographical errors were corrected, and non-substantive clarifications were made to text, Findings of Fact, Conclusions of Law and Ordering Paragraphs.

8. 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 2016 LCR study were discussed and recommended in a CAISO stakeholder meeting, and they generally mirror those used in the 2007 through 2015 LCR 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 of being flexibly dispatched

4. There is sufficient overall flexible capacity in the CAISO Balancing Authority Area to meet flexible capacity needs in 2016. 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.

5. CAISO-recommended flexible capacity needs increased substantially from those identified for 2015. Much of this change was due to the inclusion of 2,181 MW of incremental behind-the-meter solar production in this year's study.

6. The CAISO calculated flexible capacity needs for 2016 based on the methodology adopted in D.13-06-024.

7. In the RA program, system capacity is allocated to LSEs using the load-ratio share method.

8. Avoided line loss values are often located in confidential workpapers in General Rate Case Application proceedings, causing difficulty determining whether the line losses figures in the workpapers are cumulative or separable.

9. Line loss figures currently used to gross-up DR resources in the RA proceeding are not the same as those currently used in the LTPP or the CAISO's TPP.

10. D.09-06-028 codified the calculation of QC for different types of generation resources as they count towards RA obligations. The adopted QC Calculation Manual lays out the method used to calculate the QC for dispatchable and non-dispatchable generators.

11. The existing QC manual leads to incorrect or unintended outcomes in the following ways: 1) grouping solar photovoltaic and solar thermal into one category when using the exceedance methodology results in inaccurate needs; 2) including test data in QC calculations leads to QC values that reflect a distorted performance history that fails to realistically represent the contribution of facilities towards meeting RA needs; and 3) use of proxy data can result in elimination of a large part of the performance history of facilities.

12. Energy Division's proposal to eliminate test data from the QC calculation is consistent with the purpose of QC calculations to represent the expected contribution of facilities towards RA obligations. The CAISO's amendment to the proposal regarding the use of a weighted average of technology factors and historical performance represents a fair and innovative remedy for the problem of facilities that come online in phases.

13. PG&E's proposal to redefine dispatchability for cogeneration facilities that are unable to bid into the real-time market, but are nevertheless able to submit schedules into the day-ahead market and respond to some limited CAISO dispatch instructions would recognize the QC value of a resource that can be scheduled to its Pmax when the CAISO finds it beneficial to do so even though there may be some dispatch restrictions.

14. MCE's proposal to unbundle CAM net capacity costs would require a change to the CAM mechanism established in D.06-07-029.

15. AReM's request that the Commission provide additional online information to assist CCAs and ESPs in minimizing over-procurement would increase transparency but not change the CAM mechanism.

16. MCE's proposal that the Energy Division provide twelve distinct forecast values, one per month, for the full year-ahead CAM-related capacity allocation forecasts would not constitute a change to the CAM mechanism. Providing LSEs with this information will help them to minimize over-procurement and improves transparency needed for efficient procurement planning.

17. The CEC is acting consistently with the Commission's intent in adjusting LSE load forecasts for the purpose of setting RA requirements.

18. There needs to be more transparency and consistency in the current load forecast adjustment process.

19. Under the current flexible RA counting rules, storage resources with a non-zero transition between charge and discharge can only count their discharge capacity towards their effective flexible capacity value, despite the ability of these resources to provide flexibility by charging.

20. The order from D.14-06-050 for one incremental local true-up allocation, to adjust Local RA obligations from July compliance through December is in the process of being implemented for the 2015 RA compliance year.

21. During some months of the year, an LSE may be required to demonstrate local capacity in excess of its total system monthly peak demand and reserve margin.

22. There are potential efficiency gains from unbundling flexible capacity from system capacity, but there remains significant uncertainty and potential for negative impacts.

23. The DRAM Pilot is an important step forward in terms of integrating supply-side DR into the CAISO market. As this is a new program expected to begin in June 2016, there is no historical performance data available on which to base QC calculations.

Conclusions of Law

1. The CAISO's 2015 Local Capacity Technical Analysis Final Report and Study Results is reasonable and should be approved as the basis for establishing local procurement obligations for 2016 applicable to Commission-jurisdictional LSEs.

2. The CAISO's Final Flexible Capacity Needs Assessment for 2016 is reasonable and should be approved as the basis for establishing local procurement obligations for 2016 applicable to Commission-jurisdictional LSEs.

3. Energy Division should implement the RA program for 2016 in accordance with the adopted policies in this and previous decisions.

4. Energy Division's proposal to use the adopted LTPP assumptions and scenarios available at the time Energy Division allocates DR QC values for the next RA compliance year for purposes of "grossing-up" QC values for DR

resources to account for avoided line losses in the RA process, is reasonable because it will increase consistency across Commission proceedings and reduce administrative burden.

5. Energy Division's proposal to revise the QC Calculation Manual to specify calculation of one set of technology factors for solar thermal facilities and another for PV facilities is reasonable and should be adopted. QC for resources that come online in phases should be based on historical production after the phase reaches commercial operation excluding test data. Remaining phases under construction will be assessed using technology factors and a MW weighted average of each part will comprise the total QC of the facility.

6. It is reasonable to modify the QC definitions to allow RA resources that are capable of operating in accordance with day-ahead and pre-day-ahead scheduling instruction, but are not fully capable of responding to real-time dispatch instructions, to be given a QC value based on Pmax, rather than based on historical output.

7. Unbundling CAM net capacity costs is an issue scoped into R.13-12-010 and should be considered in that proceeding.

8. AReM's request that the Commission provide additional online information to assist CCAs and ESPs in minimizing over-procurement is reasonable.

9. MCE's proposal that the Energy Division provide twelve distinct forecast values, one per month, for the full year-ahead CAM-related capacity allocation forecasts is reasonable.

10. Per the Scoping Memo in this proceeding, DR issues should be addressed in Phase 3 of this proceeding.

11. Shell's proposal to improve the current transparency and consistency of the forecast allocation process is reasonable and should be adopted.

12. The CAISO's proposal that an LSE's local capacity requirement should be capped at that LSE's system requirement in the monthly resource adequacy process is reasonable and should be adopted.

13. Unbundling flexible capacity from system capacity should be deferred until the 2017 compliance year or in conjunction with consideration of a more durable flexible product.

ORDER

IT IS ORDERED that:

1. The California Independent System Operator's 2016 Local Capacity Technical Analysis Final Report and Study Results, filed May 4, 2015, is adopted as the basis for establishing local procurement obligations for 2016 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 4, 2015, 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 2016 are as follows:

	2016 LCR Need Based On Category C with Operating Procedure		
Local Area Name	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**
Humboldt	167	0	167
North Coast / North Bay	611	0	611
Sierra	1,765	253	2,018
Stockton	422	386	808
Greater Bay	4,218	131	4,349
Greater Fresno	2,445	74	2,519
Kern	400	0	400
LA Basin	8,887	0	8,887
Big Creek/ Ventura	2,398	0	2,398
San Diego/ Imperial Valley	3,112	72	3,184
Total	**24,425**	**916**	**25,341**

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, D.13-06-024 and D.14-06-050 for compliance years 2008 through 2015, respectively, are continued in effect for compliance year 2016, subject to the modifications, refinements, and local capacity requirements adopted in ordering paragraphs in this decision.

4. The California Independent System Operator's Final 2016 Flexible Capacity Needs Assessment, filed May 4, 2015, is adopted as the basis for establishing flexible procurement obligations for 2016 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 2016 are as follows:

NOTE: All numbers are in Megawatts	CAISO System Flexible Requirement	CPUC Flexible Requirement	CPUC		
			Category 1 (minimum)	Category 2 (100% less Cat. 1 & 3)	Category 3 (maximum)
January	11,103	10,429	6,625	3,283	521
February	10,507	10,050	6,384	3,163	502
March	10,362	9,894	6,285	3,114	495
April	9,989	9,389	5,964	2,955	469
May	7,731	7,417	6,458	589	371
June	7,244	6,967	6,065	553	348
July	7,935	7,546	6,570	599	377
August	7,998	7,606	6,622	604	380
September	9,259	8,825	7,683	701	441
October	10,331	9,886	6,280	3,112	494
November	12,005	11,462	7,281	3,608	573
December	12,817	12,179	7,737	3,834	609

5. The Commission's Resource Adequacy program is modified as follows:

A) Adopted transmission and distribution line loss assumptions and scenarios from the Long-Term Procurement Plans proceeding (currently Rulemaking 13-12-010) available at the time Energy Division allocates demand response Qualifying Capacity Values for the next Resource Adequacy compliance year shall be used for purposes of "grossing–up" Qualifying Capacity values for demand response resources to account for avoided line losses in the Resource Adequacy process.

B) The Qualifying Capacity Calculation Manual shall be revised to specify calculation of one set of technology factors for solar thermal facilities and another for photovoltaic facilities.

C) For the 2016 Resource Adequacy compliance year only, Qualifying Capacity for resources that come online in phases shall be based on historical production after the phase reaches commercial operation excluding test data. Remaining phases under construction will be assessed using technology factors and a megawatt-weighted average of each part shall comprise the total Qualifying Capacity of the facility.

D) For 2016 Resource Adequacy compliance year only, Energy Division will not calculate proxy data for generators whose performance history may be affected by scheduled or forced outages. Instead QC for non-dispatchable resources will be based on the entire three years of production data, regardless of outage history.

E) The QC definitions shall be modified to create a category called "Pre-Dispatch" to include Resource Adequacy resources that are capable of operating in accordance with day-ahead and pre-day-ahead scheduling instruction, but are not fully capable of responding to real-time dispatch instructions. The "Pre-Dispatch" RA resource classification will be restricted to QF Cogeneration facilities only, not other types of QF resources and not including any non-QF resources. QC for Pre-Dispatch facilities will be based on MW scheduled amounts, not settlement data.

F) Energy Division shall publish a list of the Cost Allocation Mechanism resources per Decision 06-07-029 (including capacity values and contract dates) that were included in the allocation on its Resource Adequacy compliance website.

G) Energy Division shall provide twelve distinct forecast values, one per month, for the full year-ahead Cost Allocation Mechanism-related (per Decision 06-07-029) capacity allocation forecasts. Energy Division shall provide load-serving entities with twelve monthly Cost Allocation Mechanism values as part of its annual year-ahead allocation.

H) Energy Division shall publish the following documents following the initial Resource Adequacy year-ahead allocations around the end of July in each year:

1. The five monthly dates and times of the California Independent System Operator system peak used in each load-serving entities' coincident calculation and the five monthly "OASIS" coincident peaks;
2. The California Energy Commission's step-by-step process for load forecast adjustment; and
3. Any discretionary adjustments made with a detailed explanation of the adjustment and why it was made (using proxy load data).

I) Each load-serving entity's (LSE's) local capacity requirement shall be capped at that LSE's system requirement in the monthly resource adequacy process.

J) Local Resource Adequacy requirements shall be capped at monthly system Resource Adequacy requirements.

6. Decision 14-06-050, Appendix B, is modified to eliminate the prohibition on non-zero transition times, and to allow up to 45 minute transition times that shall not count towards either the one-and-a-half hour charge or discharge.

7. The April 20, 2015, motion of Southern California Edison Company and San Diego Gas & Electric Company is granted to permit the MegaWatt contract quantities obtained through the Demand Response Auction Mechanism Pilot for 2016 to be (i) used to determine the Qualifying Capacity; and (ii) exempted from the Load Impact Protocol requirement as specified in Decision 14-06-050.

8. Rulemaking 14-10-010 remains open.

This order is effective today.

Dated June 25, 2015, at San Francisco, California.

MICHAEL PICKER
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
LIANE M. RANDOLPH
Commissioners