Decision 19-06-026 June 27, 2019

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 2019 and 2020 Compliance Years.	Rulemaking 17-09-020

DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2020-2022, ADOPTING FLEXIBLE CAPACITY OBLIGATIONS FOR 2020, AND REFINING THE RESOURCE ADEQUACY PROGRAM

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DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2020-2022, ADOPTING FLEXIBLE CAPACITY OBLIGATIONS FOR 2020, AND REFINING THE RESOURCE ADEQUACY PROGRAM

Summary

This decision adopts local capacity requirements for 2020-2022 and flexible capacity requirements for 2020 applicable to Commission-jurisdictional electric load-serving entities.

This decision also makes minor refinements to the Resource Adequacy program.

This proceeding remains open.

1. Background

In June 2018, the Commission issued Decision (D.) 18-06-030, which adopted local capacity obligations for 2019 and resolved certain issues designated as Track 1 of this proceeding. The Commission also issued D.18-06-031 in June 2018, adopting flexible capacity obligations for 2019. In February 2019, the Commission issued D.19-02-022, which adopted refinements to the Resource Adequacy (RA) program, including the implementation of a multi-year local RA requirement to begin for the 2020 compliance year.

A Scoping Memo and Ruling (Scoping Memo) for this proceeding was issued on January 18, 2018, which set forth the three tracks for this proceeding. On January 29, 2019, an Amended Scoping Memo and Ruling (Amended Scoping Memo) was filed that clarified the issues and schedule for Track 3 of this proceeding.

The Administrative Law Judge's (ALJ) ruling, dated November 16, 2018, filed and served a proposal by the Commission's Energy Division regarding Effective Load Carrying Capacity (ELCC). A webinar on the ELCC proposal was held on December 13, 2018. An ALJ ruling, dated February 13, 2019, filed and served Energy Division's revised ELCC proposal and requested that comments to the proposal be incorporated in Track 3 comments.

Track 3 proposals were filed and served by parties on March 4, 2019. The parties that submitted proposals were: Alliance for Retail Energy Markets (AReM); California Community Choice Association (CalCCA); Center for Energy Efficiency and Renewable Technologies (CEERT); California Energy Storage Alliance (CESA); California Independent System Operator (CAISO); California Wind Energy Association (CalWEA); CPower, Enel X North America, Inc. (Enel X), and EnergyHub (collectively, the Joint Demand Response (DR) Parties); Independent Energy Producers Association (IEP); Middle River Power, LLC (Middle River); Pacific Gas and Electric Company (PG&E); San Diego Gas & Electric Company (SDG&E); Sunrun Inc. (Sunrun); Southern California Edison Company (SCE); Wellhead Electric Company, Inc. (Wellhead); and Western Power Trading Forum (WPTF). Energy Division's Track 3 proposal was filed and served by an ALJ ruling, dated March 4, 2019.

A workshop on Track 3 proposals was held on March 12-13, 2019. Comments on the workshop and proposals were filed on March 22, 2019 and reply comments were filed on March 29, 2019.

Comments were received from AReM; CalCCA; CAISO; California Efficiency + Demand Management Council (Council); California Large Energy Consumers Association (CLECA); Calpine Corporation (Calpine); CEERT; CESA; CalWEA; Green Power Institute (GPI); IEP; Joint DR Parties; Large-scale Solar Association (LSA); LS Power Development, LLC (LS Power); Middle River; NRG Energy, Inc. (NRG); OhmConnect, Inc. (OhmConnect); PG&E; Public Advocate's Office (Cal Advocates); SDG&E; Shell Energy North America (US), L.P. (Shell);

Sierra Club, Union of Concerned Scientists, and California Environmental Justice Alliance (collectively, the Joint Environmental Parties); Sentinel Energy Center, LLC (Sentinel) and Diamond Generating Corporation (Diamond) (collectively, Sentinel/Diamond); SCE; Sunrun; Wellhead; and WPTF.

Reply comments were received from CAISO, CLECA, Calpine, CEERT, LSA, Middle River, NRG, PG&E, SDG&E, SCE, Sunrun, The Utility Reform Network (TURN), and Wellhead.

2. Issues Before the Commission

The Amended Scoping Memo identified the following issues as within the scope of Track 3[1]:

(1) Adoption of the 2020 Local Capacity Requirements (LCR);

(2) Adoption of the 2020 Flexible Capacity Requirements (FCR);

(3) Adoption of the 2020 System RA Requirements;

(4) Further Refinements of the Resource Adequacy Program;

(5) Consideration of other modifications and refinements to the RA program as identified in proposals by Energy Division or by parties.

The fourth category includes: (a) revisions to the load forecast methodology, (b) consideration of how storage and combined resources should be counted for RA credit, and (c) refinements to the third-party demand response qualifying capacity methodology.

All proposals and comments submitted by parties were considered, but given the number of parties and issues, some proposals and issues may receive little or no discussion in this decision. Issues within the scope of the proceeding

[1] Amended Scoping Memo at 3.

that are not addressed here, or that are only partially addressed, may be addressed in a later phase of this proceeding.

3. Discussion

3.1. 2020-2022 Local Capacity Requirements

The local 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. A series of subsequent decisions (most recently D.18-06-030), established local procurement obligations for 2008 through 2019. The local RA program and associated regulatory requirements adopted in those decisions continue in effect until changed, subject to the 2020-2022 LCR and procurement obligations adopted by this decision.

D.06-06-064 determined that a study of LCR, performed by the CAISO, would form the basis for the Commission's local RA program. The CAISO conducts its LCR study annually and the Commission resets local procurement obligations each year after a review of the CAISO's LCR recommendations. Local RA requirements are allocated to Commission-jurisdictional load-serving entities (LSE) and each LSE must procure sufficient RA capacity resources in each local area to meet their obligations.

Most recently, in D.19-02-022, the Commission adopted multi-year local RA requirements for a three-year duration to begin for the 2020 compliance year. The Commission determined that the requirements would be based on the CAISO's existing one- and five-year LCR studies, with the incorporation of engineer-managed adjustments for CAISO-approved transmission projects.[2] This year, the CAISO's draft LCR study was received on April 4, 2019, and parties filed comments to the draft LCR study on April 18, 2019.

[2] D.19-02-022 at 22.

The CAISO filed its final LCR study for 2020-2022 on May 1, 2019. The CAISO states that the assumptions, processes, and criteria used for the LCR study were discussed and recommended in a stakeholder meeting, and on balance mirror those used in the 2007 through 2019 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 states that total LCR needs decreased by 961 megawatts (MW) or ~3.9 percent for 2020. For specific regions, needs decreased in Humboldt, Big Creek/Ventura, and LA Basin due to load forecast decrease, Sierra due to new transmission projects, and San Diego due to unavailability of solar at 8:00 p.m. and a combination of mitigation measures evaluated. 2020 LCR needs increased in North Coast/North Bay, Bay Area, Stockton, Fresno, and Kern due to load forecast increase.

Due to the Commission's adoption of a multi-year local RA requirement in D.19-02-022, the CAISO provided engineering estimates for the 2021 and 2022 LCR for the first time in this study. The CAISO's recommended 2020-2022 LCR values are summarized in the following table, with the 2019 LCR provided for comparison.

2020-2022 Local Capacity Requirements			
	LCR Need Based on Category C*** with Operating Procedure		
Local Area Name	**2020**	**2021**	**2022**
Humboldt	130	131	131
North Coast/North Bay	742	672	684
Sierra	1764*	1765*	1765*
Stockton	629*	629*	629*
Greater Bay	4550	4511	4473
Greater Fresno	1694*	1698*	1703*
Kern	465*	465*	465*
Big Creek/Ventura	2410*	2576*	2576*
LA Basin	7364	7152*	6243
San Diego/Imperial Valley	3895	4036*	3929
Total	23643	23635	22598

* CAISO note: No local area is "overall deficient". Details about magnitude of deficiencies can be found in the applicable section [of the LCR Report]. 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.

2019 Local Capacity Requirements			
2019 LCR Need Based on Category C*** with Operating Procedure			
Local Area Name	Existing Capacity Needed**	Deficiency	Total (MW)
Humboldt	165	0	165
North Coast/North Bay	689	0	689
Sierra	1964	283*	2247
Stockton	427	350*	777
Greater Bay	4461	0	4461
Greater Fresno	1670	1*	1671
Kern	472	6*	478
LA Basin	8116	0	8116
Big Creek/Ventura	2614	0	2614
San Diego/Imperial Valley	4026	0	4026
Total	24604	640	25244

* 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.

*** CAISO note: TPL 002 Category B is generally equivalent to TPL 001-4 Category P1. TPL 003 Category C is generally equivalent to TPL 001-4 P2 through P7. Current LCR study report is compliant with existing language in the ISO Tariff Section 40.3.1.1 Local Capacity Technical Study Criteria to be revised at a later date.

Only PG&E filed and served comments to the final LCR study on May 8, 2019. In its comments, PG&E advocates for establishing a working group to comprehensively evaluate the LCR process and ensure that enhancements to methodologies or studies may be implemented for the 2021-2023 local RA requirements. PG&E recommends a working group to specifically "examine the relationship between local RA requirements, RA resource obligations, changes to NQC in forward years, how RA performance in assessed, and how local RA backstop procurement occurs or does not occur from uncured deficiencies."[3] The Commission finds PG&E's proposal to be reasonable, and directs Energy Division to establish a working group to evaluate improvements and refinements prior to the development of the 2021-2023 local RA requirements.

The Commission finds the CAISO's recommended 2020-2022 LCR values to be reasonable and accordingly, we adopt the CAISO's recommended values set forth in the table above.

3.2. 2020 Flexible Capacity Requirements

D.13-06-024 and D.14-06-050 adopted a flexible capacity requirement to begin in 2015 and defined implementation guidelines. 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 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."[4]

This year, the CAISO's draft Flexible Capacity Requirements study was received on April 4, 2019, and parties filed comments to the draft FCR study on April 18, 2019.

The CAISO's final Flexible Capacity Needs Assessment for 2020 (FCR Report) was due on May 1, 2019. On that date, the CAISO filed a Notice of Availability for the 2020 Local Capacity Technical Study stating that "additional time is necessary to complete the process. Consequently, as discussed with the

[3] PG&E Comments to Final LCR Report at 2.

[4] D.13-06-024 at 2.

Commission's Energy Division staff and management, the CAISO intends to complete the final 2020 FCR Report and provide it to the Commission on May 15, 2019."[5] A May 6, 2019 ruling provided that, upon the CAISO's filing of its final FCR Report, responsive comments to the FCR Report must be submitted by May 20, 2019.

The CAISO filed and served its final FCR Report on May 15, 2019. The final FCR Report contained the following figures for 2020, with the 2019 FCR provided for comparison.

2020 Flexible Capacity Requirements

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	18,500	17,646	6,367	10,397	882
February	18,626	18,025	6,504	10,620	901
March	17,700	17,127	6,180	10,091	856
April	17,380	16,662	6,012	9,817	833
May	16,438	15,759	8,291	6,680	788
June	15,108	14,522	7,640	6,156	726
July	12,331	11,812	6,214	5,007	591
August	14,660	13,982	7,356	5,927	699
September	15,958	15,339	8,070	6,502	767
October	17,259	16,698	6,025	9,838	835
November	18,260	17,695	6,385	10,425	885
December	17,810	17,211	6,210	10,140	861

[5] CAISO's Notice of Availability of Final 2020 Local Capacity Technical Study, May 1, 2019.

2019 Flexible Capacity Requirements					
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	15,651	14,608	6,752	7,125	730
February	16,011	14,987	6,928	7,310	749
March	16,071	15,279	7,063	7,453	764
April	14,755	13,898	6,424	6,779	695
May	13,052	12,331	7,700	4,015	617
June	13,839	13,118	8,192	4,271	656
July	11,517	11,056	6,904	3,599	553
August	11,990	11,637	7,267	3,789	582
September	15,067	14,209	8,873	4,626	710
October	14,821	14,131	6,532	6,893	707
November	15,022	14,152	6,542	6,903	708
December	16,323	15,493	7,162	7,557	775

Only PG&E filed responsive comments to the final FCR Report on May 20, 2019. In comments, PG&E recommends that the CAISO align its summer and winter month definitions in both the Final 2020 Availability Assessment Hours Report and the Final 2020 FCR Report, and that the CAISO account for wind and solar resource curtailments when calculating ramping requirements. PG&E also recommends that the CAISO cross-reference LSEs' survey data on renewable generation contracted with LSEs against other data in CAISO's possession to estimate flexible requirements.[6] PG&E raises potential

[6] PG&E Comments to Final FCR Report at 2.

valid concerns and the Commission encourages the CAISO to work to address these issues in future studies or workshop discussions.

In light of the brief review period available for the Final FCR Report, the FCR figures appear reasonable. Accordingly, we adopt the CAISO's recommended values set forth in the table above.

3.3. 2020 System Requirements

In the Amended Scoping Memo, one of the Track 3 issues is "Adopting the 2020 System RA Requirements." Under that heading, it reads:

> The Commission has imposed a system requirement based on the California Energy Commission (CEC) 1-in-2 monthly load forecast, plus a 15% planned reserve margin. This framework is expected to continue for the 2020 RA program year.[7]

Based on the minimal record development in Track 3 on issues relating to refining the System RA requirements, we decline to make any changes to the current System RA requirement methodology at this time.

3.4. RA Waiver and Penalty Process

The Commission adopted a penalty structure for an LSE's failure to meet its system RA and local RA obligations in D.05-10-045 and D.06-06-064, respectively. In D.06-06-064, the Commission also established a waiver process for local deficiencies and set a trigger price of $40/kW-year.[8] The adopted trigger price was deemed a price that "could lead to the granting of a waiver" but would not be the sole factor in granting a waiver, as other factors such as contracts terms and conditions could be considered.[9] In D.10-06-036, a penalty

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[7] Amended Scoping Memo at 3.

[8] D.06-06-064 at 74.

[9] *Id*. at 72.

price of $6.66/kW-month was adopted for system RA deficiencies. We consider several proposed modifications to the RA waiver process.

3.4.1. Local Waiver Trigger Price

In D.11-06-022, the Commission considered changing the local waiver trigger price but declined to do so finding that the waiver process had scarcely been used since 2007 with only three waiver applications filed up to that point. The Commission concluded that this "shows that LSEs do not appear to be subject to market power in such a way as to make compliance with RA obligations impossible."[10] In recent years, however, a tightening of the local RA market has been observed, with an increasing number of LSEs relying on local waivers. From 2006 - 2017, the Commission received only three local waiver requests. However, in both 2018 and 2019, the Commission received 11 local waiver requests for year ahead filings.[11]

Given these circumstances, Energy Division proposes updating the local waiver trigger price from $40/kW-year to an annualized value of the 85th percentile of the monthly South of Path 26 local RA value, or $51/kW-year.[12] Multiple parties support raising the local waiver trigger price, including CLECA, Calpine, NRG, PG&E, SDG&E, Shell, and WPTF, although parties have differing views about what the trigger price should be.

CLECA and Shell support raising the price to $51/kW-year.[13] Calpine, Middle River, NRG, and WPTF recommend that the price be linked to the CAISO's Capacity Procurement Mechanism (CPM) pricing, which is currently

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[10] D.11-06-022 at 34.

[11] Energy Division Track 3 Proposal at 24.

[12] *Id.*

[13] CLECA Opening Comments at 4, Shell Opening Comments at 6.

near the soft-offer cap price of $6.31/kW-month, since that is a primary factor in an LSE's decision to accept or reject an offer.[14] PG&E recommends using an annualized value of the statewide 85th percentile value rather than the South of Path 26 85th percentile, because the latter may not reflect the overall state conditions for local RA capacity.[15] AReM opposes the $51/kW-year price, which is based on RA market prices, and instead supports an administratively-set fixed price.[16]

We agree that the local waiver trigger price should be updated to reflect current market conditions since the trigger price has not been changed since the local RA requirement was first adopted in 2006. We reiterate that an offer at or above the trigger price is a necessary, but not sufficient, reason for the Commission to grant a local waiver. While it may be reasonable for an LSE to sign an annual RA contract at or above the soft-offer cap (*e.g.*, for new generation), that price may be too high for market power mitigation since the soft-offer cap includes a 20 percent adder above going forward costs and retention of market revenues. Thus, we decline to adopt the soft-offer cap as the local waiver trigger price.

The Commission finds it reasonable to raise the local trigger price to an annualized value of the 85th percentile of the monthly local RA prices for South of Path 26, or $51/kW-year. This is a static trigger price that will remain in effect until changed by a future Commission decision. Setting the trigger price at $51/kW-year allows the Commission to consider the highest priced capacity

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[14] Calpine Opening Comments at 3, Middle River Reply Comments at 3, NRG Opening Comments at 8, WPTF Opening Comments at 3.

[15] PG&E Opening Comments at 9.

[16] AReM Opening Comments at 8.

offers and gives the Commission discretion to grant waivers in circumstances where market power may have been exerted.

Additionally, SDG&E recommends that if the local trigger price is revisited, the bundled capacity and energy product trigger price of $73/kW-year should also be reconsidered.[17] We agree that the bundled trigger price, which was adopted at the same time as the $40/kW-year local capacity trigger price, is likely outdated. However, since no waiver has ever been requested for a bundled product and no alternate price has been proposed, we find insufficient record support to revise the bundled capacity and energy price at this time.

Cal Advocates recommends that if the trigger price is increased, the local penalty price should be increased to an equivalent level.[18] For example, if the trigger price is raised to $51/kW-year, then the current local RA penalty price of $3.33/kW-month should be raised to the equivalent $4.25/kW-month. The CAISO supports this proposal.[19] The Commission agrees with Cal Advocates that the local penalty price should be raised to match the local trigger price. This avoids a scenario where an LSE that can meet its RA obligation by accepting a price higher than the penalty price, but lower than the waiver price, may be incentivized to decline a bid and pay the lower penalty price since it cannot qualify for a local waiver.

Accordingly, the Commission updates the local trigger price from $40/kW-year to an annualized value of the 85th percentile of the monthly South of Path 26 local RA value, or $51/kW-year. The Commission also raises the local

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17 SDG&E Opening Comments at 9.

18 Cal Advocates Opening Comments at 9.

19 CAISO Reply Comments at 8.

RA penalty price of $3.33/kW-month to $4.25/kW-month, the equivalent value of the newly-adopted trigger price of $51/kW-year.

Lastly, a few parties, including AReM, Cal Advocates, and Shell, recommend that the Commission examine the source of the increased waiver requests, and determine whether they are due to the withholding of capacity in the market.[20] The Commission notes that Energy Division has undertaken to investigate the source of increased waiver requests in this proceeding. Specifically, in D.19-02-022, we directed Energy Division to prepare reports that will include information regarding the "number of local RA waiver requests, and anonymized statements from the LSE as to the reason for the deficiency…"[21] We also expect that the source of the increase in waiver requests will be discussed in future workshops and may be addressed in a forthcoming Commission decision.

3.4.2. Advice Letter Process for Waivers

Currently, local RA waiver requests are received and processed confidentially by Commission staff and information about those requests, including the number of requests and identity of requesters, can only be obtained through a California Public Records Act[22] request or if Commission staff discloses information on the Commission's website. Due to the increased number of waiver requests in recent years, there has been significant interest from stakeholders in obtaining the underlying information and parties have done so through the Public Records Act process.

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[20] AReM Opening Comments at 8, Cal Advocates Opening Comments at 8, Shell Opening Comments at 6.

[21] D.19-02-022 at 31.

[22] California Government Code § 6250 et seq.

Energy Division proposes that local RA waiver requests be submitted via a Tier 2 Advice Letter in an effort to promote transparency among all parties and establish a routine process for the treatment of local waiver requests.[23] AReM, Calpine, and Cal Advocates support this approach, although AReM seeks clarification that the confidentiality rules of D.06-06-066 apply.[24] SDG&E opposes an Advice Letter process, arguing that it creates unnecessary burden and delay for seeking a waiver and is redundant to the requirement in D.19-02-022 that Energy Division issue reports on local RA deficiencies and waiver requests.[25] Shell opposes the Advice Letter process because the substantive information in a waiver request is confidential.[26] Shell and SDG&E instead recommend posting non-confidential information about an LSE's local waiver request on the Commission's website.

Considering the recent uptick in local waiver requests, the Commission finds it appropriate to establish a formal, transparent waiver review process. Parties can and do access the underlying local waiver information through Public Records Act requests, which allows a disproportionate disclosure of information among parties. We are not persuaded by some parties' confidentiality concerns since parties may redact confidential information from Advice Letters and submit confidential versions as needed. The Commission concludes that establishing a formal local waiver request process is a logical step to promoting transparency among all parties. Accordingly, the Commission adopts the requirement that local RA waiver requests shall be submitted via a Tier 2 Advice

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[23] Energy Division Track 3 Proposal at 25.

[24] AReM Opening Comments at 10, Calpine Opening Comments at 4, Cal Advocates Opening Comments at 8.

[25] SDG&E Opening Comments at 10.

[26] Shell Opening Comments at 7.

Letter with service of a redacted version (if any) to the service list in the Resource Adequacy proceeding open at the time of the request.

Additionally, SCE proposes that the existing waiver process should be extended to system and flexible RA as well, and that the trigger price for system and flexible RA should be the soft-offer cap for the CAISO's CPM.[27] NRG and Calpine oppose this, stating that while there is general agreement that the RA market is tightening, there is no clear demonstration of the ability to exercise market power for system or flexible RA capacity.[28] SDG&E does not oppose the proposal but states that it should be considered alongside the unbundling of system and flexible RA.[29]

The Commission recognizes the concern that a tightening RA market may necessitate system and flexible RA waivers for circumstances beyond the control of an individual LSE. However, there remain significant, unresolved issues that require further consideration before allowing such waivers, including potential leaning by LSEs and market power issues. Such market power issues may include potential gaming by generators that may, for example, withhold capacity during more expensive peak months. While we decline to extend the waiver process beyond local RA at this time, the Commission encourages further discussion of these issues through workshops or in a later phase in this proceeding.

Lastly, because the Commission declines to extend the waiver process to system and flexible RA at this time, we emphasize that any waiver request

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[27] SCE Opening Comments at 2.

[28] Calpine Opening Comments at 12, NRG Opening Comments at 11.

[29] SDG&E Opening Comments at 11.

nonetheless submitted for system or flexible RA deficiencies will be automatically rejected.

3.4.3. Flexible RA Penalty Calculation

In adopting a waiver process for local deficiencies in D.06-06-064, the Commission clarified that if an LSE was deficient for both local and system RA, the penalty was not cumulative but the "larger System RAR penalty would apply."[30] However, when the Commission adopted flexible RA capacity requirements in D.14-06-060, it did not include similar language that the penalty for flexible deficiencies was not in addition to system RA penalties.

Energy Division proposes a clarification that where an LSE incurs both flexible and system RA deficiencies, the penalty will be based on whichever MW amount is greater, but not the sum of the two penalties.[31] Shell support this proposal.[32] Calpine supports the proposal but seeks clarification that: (1) if a system RA deficiency is matched by a flexible RA deficiency, the system RA capacity will be penalized at the system RA penalty price (but not an independent penalty on the corresponding flexible deficiency); and (2) if a flexible deficiency exceeds a system deficiency, the penalty for the excess flexible deficiency will be at the flexible capacity penalty price.[33]

The Commission agrees that a clarification of the flexible RA penalty is appropriate and agrees with Calpine's characterization of the penalty application process. Accordingly, if an LSE faces both flexible RA and system RA deficiencies, the penalty shall be based on the following: (1) where an LSE has

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[30] D.06-06-064 at 74.

[31] Energy Division Track 3 Proposal at 24.

[32] Shell Opening Comments at 7.

[33] Calpine Opening Comments at 3.

equivalent flexible and system deficiencies, the system RA penalty price of $6.66/kW-month shall apply; and (2) where an LSE's flexible deficiency exceeds its system deficiency, the system RA penalty price shall apply to the MW amount of the system deficiency, and the flexible RA penalty price (of $3.33/kW-month) shall apply to the MW amount of the flexible deficiency in excess of the system deficiency.

3.4.4. Trigger Price for Partial Year Offers

In D.06-06-064, the Commission adopted the local RA trigger price of $40/kW-year and stated that "we are not adopting a monthly price trigger; specifically, we are not adopting a trigger price of one-twelfth of the yearly price trigger ($3.33 per kW-month), as we would not expect RAR prices to be uniform throughout the year."[34]

Without a comparative monthly RA offer, SDG&E contends that it is difficult to determine the reasonableness of a waiver request and proposes adopting a mechanism that compares an "equivalent" annual RA offer to the kW-year capacity cost trigger price.[35] The Commission understands the interest in establishing a comparative monthly price to give LSEs greater certainty. However, as stated in D.06-06-064, the Commission declines to set a monthly trigger price due to the lack of consistency in RA prices throughout the year. We encourage LSEs to explain their individual circumstances in a Tier 2 Advice Letter if seeking a local waiver, and the reasonableness of the deficiency will be evaluated on a case-by-case basis.

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[34] D.06-06-064 at 72.

[35] SDG&E Proposal at 3-4.

3.5. Adjustments to the Load Forecast Process

Beginning with D.04-10-035 and D.05-10-042, the Commission adopted the RA program's load forecast adjustment methodology, in which LSEs were directed to submit load forecasts to the California Energy Commission (CEC) that would be adjusted for coincidence and program impacts (energy efficiency, distributed generation, and demand response), and assessed for plausibility and consistency with the CEC's aggregate forecast. The RA forecast adjustment methodology was further refined in several decisions, including D.10-13-039, D.11-06-022, D.12-06-025, and D.17-06-027.

With the recent proliferation of LSEs and substantial load migration to Community Choice Aggregators (CCAs), the load forecasting process has become increasingly complicated. As stated in Energy Division's proposal, 15 LSEs participated in the year ahead process in 2011, 21 LSEs participated in 2016, and 36 LSEs participated in the 2019 year ahead process. Additionally, load allocated to CCAs in the year ahead process went from two percent of the peak in 2016 to 25 percent of the peak in 2019. Energy Division anticipates "this trend towards disaggregation of load to continue, with eleven CCAs planning to launch or expand in 2020. The re-opening of direct access by [Senate Bill] 237 will likely also result in increased load migration and the entrance of new [Electric Service Providers] ESPs into the California market."[36]

Energy Division analyzed the growing differences between LSEs' coincidence-adjusted forecasts and final adjusted forecasts and the factors underpinning those differences. One such factor is LSEs' use of different forecasting methods in their forecast adjustment processes. Citing D.05-10-042, Energy Division states that since "load migration should be the only reason for

[36] Energy Division Track 3 Proposal at 9.

differences between year ahead and month ahead forecasts, the sum of changes to adjusted forecasts between the year ahead and month ahead processes across LSEs should roughly equal 0 MW."[37] However, the analysis of the sum of differences in LSE forecasts from 2015 to 2018 revealed that the sum of differences far exceeded 0 MW and the sum's absolute value has only increased since 2016. Based on LSE-reported explanations for forecasting differences between initial and final year ahead forecasts for 2019, Energy Division concluded that LSEs are utilizing a broad range of assumptions to develop their load forecasts, beyond merely load migration, and such discrepancies can be problematic for accurate aggregation and comparison purposes.[38]

In light of these developments, it is necessary to reevaluate the load forecast adjustment process and consider several proposed modifications.

3.5.1. Application of Load Migration

Based on Energy Division's aforementioned analysis, it is apparent that either LSEs are basing load forecasts on a variety of assumptions beyond solely load migration or that LSEs have differing and wide-ranging definitions of load migration. Energy Division offers two related proposals to address this issue.

One is a proposed definition of "load migration" to mean: "load effects that are tied directly to customer counts and that an LSE cannot reasonably predict or control…"[39] Energy Division recommends that load migration includes effects such as opt-out rate assumptions and new service requests but excludes "changes to implementation plans, updated weather modeling or assumptions, changes to customer class load profiles, or new or updated

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[37] *Id*. at 11.

[38] *Id*.

[39] *Id*. at 15.

customer load data…"[40] Relatedly, Energy Division proposes a clarification that "load migration" is the only allowable reason for differences between initial and final year ahead load forecasts.

Energy Division's second proposal relates to the "best estimate" approach for forecasts of future customers, adopted in D.04-10-035. Energy Division states that this approach is most critical for initial year ahead forecasts because these forecasts "should account for all data, assumptions, and criteria that LSEs can reasonably control or predict, including – but not necessarily limited to - implementation plans, weather modeling, customer class load profiles, and customer load data."[41] Since LSEs can reasonably predict or control this information, these assumptions should not change between an LSE's initial and final year ahead load forecast. For those effects an LSE cannot reasonably control or predict, such as opt-out rates and new service requests, an LSE should make reasonable placeholder assumptions.

CLECA, Cal Advocates and CalCCA support Energy Division's definition of load migration, although Cal Advocates recommends using another term for load migration, since the term is commonly used to describe movement of customers between LSEs.[42] CalCCA proposes a modification that LSEs can change their forecast in light of a *force majeure* event that has material load impacts, such as a wildfire.[43] PG&E comments that the ability of the investor-owned utilities (IOUs) to accurately forecast load is partially based on new or expanding CCAs' timely submission of accurate implementation plans.

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[40] *Id.*

[41] *Id.* at 16.

[42] CLECA Opening Comments at 4, Cal Advocates Opening Comments at 2, CalCCA Opening Comments at 3.

[43] CalCCA Opening Comments at 3.

Should those implementation plans shift or be found to be inaccurate, IOUs should be required to adjust their final year ahead load forecasts.[44] AReM proposes that if an LSE receives "better customer information on their demand prior to the August update," the LSE be permitted to adjust their final year ahead load forecast.[45]

3.5.1.1. Discussion

In order to develop accurate load forecasts for aggregation and comparison purposes, it is critical to standardize the assumptions used to develop initial load forecasts. The Commission therefore agrees that "load migration" should be the only allowable reason for differences between initial and final year ahead load forecasts.

With respect to the appropriate definition of "load migration" for purposes of the RA program, we decline to include "new service requests" in the definition, as proposed by Energy Division, because we do not anticipate that increases in load due to unanticipated new service requests will be large enough to cause reliability issues after the initial year ahead process. The Commission also declines to include a *force majeure* event in the definition. The adopted year ahead forecasts are pegged to the Integrated Energy Policy Report (IEPR), which is ultimately used by the CAISO for backstop procurement. However, the IEPR is not revised in the monthly timeframe, and therefore, including losses due to *force majeure* events would effectively lower RA requirements, thereby exposing all LSEs to potential backstop procurement.

In response to AReM's comments, we recognize that some LSEs do not receive updated historical data from IOUs until mid-year and thus must make

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44 PG&E Opening Comments at 14.

45 AReM Opening Comments at 3.

assumptions about opt-out rates in their initial April forecasts. We believe this issue should be resolved with the Commission's adoption of specific IOU data sharing requirements in this decision, discussed in Section 3.5.4.2. However, until the full implementation of the adopted data sharing requirements, it is reasonable that certain LSEs' final load forecasts may need to be modified with new or updated customer opt-out data. On an interim basis until the year ahead process for the 2022 compliance year, LSEs may incorporate changes resulting from the receipt of new or updated customer meter data in their final year ahead forecasts.

In conclusion, the Commission establishes that "load migration" shall be the only allowable reason for differences between initial and final year ahead load forecasts. The Commission adopts a modified definition of "load migration" for the purposes of the RA program to mean load effects that:

(1) Result from one or more customers' retail electric service transferring directly from one LSE to another LSE in the same Transmission Access Charge (TAC) area, and

(2) An LSE cannot reasonably predict and include in an implementation plan or in an initial year ahead load forecast.

Further, "load migration" shall <u>not</u> include the following non-exhaustive list of events: changes to approved implementation plans, changes to customer class load profiles, changes to weather assumptions, changes resulting from the receipt of new or updated customer meter data,[46] new service requests, losses due to disconnects or *force majeure* events, transfers of load out of the TAC area, or forecasting errors.

[46] As discussed, this information may be included in the definition of load migration on an interim basis until the year ahead process for the 2022 compliance year, pending the full implementation of the adopted data sharing requirement discussed in Section 3.5.4.2.

3.5.2. Additional Forecasting Modifications

CalCCA proposes that "[t]o the extent an LSE's gross under-forecasting results in a plausibility adjustment by the CEC that increases the obligations of other LSEs, the LSE causing the issue should be required to compensate affected LSEs."[47] Shell opposes this, arguing that under-forecasting by an LSE does not mean the load is unaccounted for, as in the case of load migration between ESPs.[48] AReM also opposes this, stating that the term "gross under-forecasting" is unclear and the proposal is unnecessary since if the forecast adjustment process attributes a load deficit to a specific LSE, the CEC will adjust that LSE's forecast for plausibility without distributing the *pro rata* deficit among all LSEs in the TAC.[49]

The Commission agrees with AReM's comments that under the existing forecast adjustment process, where it is clear that a single LSE understated its forecast, the CEC and Energy Division will adjust that LSE's forecast and RA requirements without spreading the load among other LSEs in the TAC area. Therefore, we deem this proposal as unnecessary and decline to adopt it. While we do not adopt specific penalties for under-forecasting at this time, we note that, pursuant to D.05-10-042, the Commission has the authority to investigate and sanction an LSE that has been shown to consistently under-forecast.[50]

Additionally, SCE proposes that the CEC develop aggregate forecasts for IOUs, ESPs, and CCAs in each TAC area, which it can compare against aggregate

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[47] CalCCA Proposal at 4.

[48] Shell Opening Comments at 4.

[49] AReM Opening Comments at 5.

[50] D.05-10-042 at 32.

forecasts that the IOUs provide.[51] This would be in addition to the CEC's comparison of its own forecasts for individual LSEs against LSEs' submitted forecasts. AReM opposes this proposal as unnecessary given Energy Division's proposed changes to the forecast adjustment process and states that greater IOU involvement in the forecast adjustment process threatens competitive neutrality.[52] CalCCA supports SCE's proposal as another check on the CEC's overall forecast but states that IOUs' load forecast data should not be considered an accurate benchmark for CCAs' aggregate forecasts.[53]

In light of the CEC's extensive experience producing forecasts and analyzing LSE filings, the Commission concludes it is unnecessary to direct the CEC as to what additional analyses it should perform, and declines to adopt this proposal.

3.5.3. Binding Load Forecast Process

In an effort to improve predictability of load and RA requirements, Energy Division proposes a Binding Notice of Intent (BNI) process that "'locks in' RA requirements based on load forecast assumptions that an LSE can reasonably predict or control."[54] The BNI would apply to the RA program alone and would not impact an LSE's legal ability to serve load. The BNI "would simply set year ahead RA requirements at a benchmark level that LSEs" and other stakeholders, including the Commission, the CAISO, and the CEC, could rely on to remain unchanged (other than to account for load migration).[55]

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[51] SCE Proposal at 1-3.

[52] AReM Opening Comments at 6.

[53] CalCCA Opening Comments at 4-5.

[54] Energy Division Track 3 Proposal at 16.

[55] *Id.*

Specifically, the proposed BNI process is described as follows: An LSE's initial year ahead load forecast will serve as the BNI for that LSE in the following year. To account for unforeseen circumstances or new or relevant information in the forecasting process, the CEC will extend the deadline for revisions to the initial forecasts to May 15. Once the initial load forecast is submitted, the LSE is responsible for the RA capacity implied by the initial load forecast – after any adjustments by the CEC and for load migration - regardless of additional changes in an LSE's implementation to new customers. Additionally, the Commission and the CEC will add plausibility review triggers to the forecast adjustment process, which if triggered, may require additional documentation, forecast revisions to better match an implementation plan, or forecast revisions to account for load migration.[56]

The proposed plausibility review triggers are:

(1) If an LSE's initial year ahead load forecast for a given month (or the system RA requirement implied by adjusting for coincidence and adding a 15 percent Planning Reserve Margin (PRM)) deviates from the corresponding forecast (or system RA requirement) in its implementation plan by more than 5 percent of the latter;

(2) If an LSE's final year ahead load forecast for a given month deviates from the corresponding initial year ahead forecast by more than 5 percent of the latter; or

(3) If an LSE's month ahead load forecast for a given month deviates from its corresponding final year ahead forecast by more than 5 percent of the latter.

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[56] *Id.*

CLECA, Cal Advocates, and PG&E support Energy Division's proposal.[57] CalCCA supports the proposal with the modification that newly launching CCAs should be permitted to make post-April changes to their forecast.[58] PG&E opposes CalCCA's request to give new CCAs more flexibility in their forecast updates because such flexibility "comes at the expense of IOUs' ability to manage the bundled portfolio…"[59]

The Commission is persuaded that Energy Division's proposed process will encourage effective forecasting in the year ahead process and discourage modifications to load forecasts for reasons other than unpredictable load migration. However, the Commission renames Energy Division's proposal as the Binding Load Forecast (BLF) process to avoid confusion with the "binding notice of intent" described in D.04-12-048 and D.05-12-041 in relation to CCAs. Accordingly, the Commission adopts Energy Division's proposal for a Binding Load Forecast process to lock in RA requirements based on load forecast assumptions that an LSE can reasonably control or predict, as well as the proposed plausibility review triggers.

Regarding CalCCA's proposal that newly launched CCAs or CCAs filing amended implementation plans receive flexibility for post-April forecast changes, we conclude that it is unnecessary and inequitable to give certain LSEs preferential treatment and decline to adopt the recommendation.

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[57] CLECA Opening Comments at 3, PG&E Opening Comments at 14, Cal Advocates Opening Comments at 4.

[58] CalCCA Opening Comments at 3.

[59] PG&E Reply Comments at 4.

3.5.4. Information Coordination Between LSEs

We next consider proposals relating to data transfers and information coordination during the forecasting process. Given LSEs' need to rely on IOUs as the only reasonable source of customer-level load data for non-IOU LSEs to develop their load forecasts, particularly new and expanding CCAs and ESPs, it is essential to establish clear data sharing and coordination guidelines.

3.5.4.1. Meet and Confer Process

Energy Division and CalCCA offer proposals to establish a meet and confer process between IOUs and non-IOU LSEs to address, and ideally agree upon, expected load migration prior to the year ahead forecast process. For purposes of discussing these proposals, we refer to Year 0 as the program year for which a year ahead forecast is due, and Year 1 and Year 2 as one and two years prior to that program year, respectively.

Energy Division offers the following proposal:

(1) Each IOU will meet individually with each non-IOU LSE in its service territory during the annual Energy Resource Recovery Account (ERRA) process prior to December 31 in Year 2. Where neither LSE is an IOU, and thus the ERRA process does not apply, the LSEs shall also meet prior to December 31 in Year 2.

(2) IOUs and non-IOU LSEs will meet collectively by February 15 of Year 1 to discuss expected migration between them for the following year. The meetings may occur via Commission workshops, Commission-led teleconferences, or a combination thereof.

(3) As part of the initial year ahead forecast due in April of Year 1, each LSE will provide the dates of meetings with other LSEs to discuss load migration and describe any agreements, or ongoing disagreements, as of the filing.[60]

CalCCA offers the following proposal: (1) LSEs that submit forecasts to IOUs during the ERRA process in Year 2 should agree on "forecast service territory" before April of Year 1, (2) the CEC should alert LSEs of any disagreements and give LSEs an opportunity to agree on forecasts prior to any plausibility adjustments, and (3) all issues should be resolved prior to June of Year 1 to allow the CEC and Energy Division to communicate initial year ahead requirements in July of Year 1.[61] CalCCA also recommends that the CEC and Energy Division make no updates to LSEs' year ahead requirements after June of Year 1.

Cal Advocates supports Energy Division's proposal, but requests clarification that the coordination occur during each IOU's ERRA forecast proceeding where the IOUs forecast load for the following year. Cal Advocates also notes that in the ERRA proceeding, IOUs make changes to their forecasts in November of Year 1 so LSEs should agree on forecasts prior to this November timeframe.[62] PG&E requests that a meet and confer process should be additive rather than redundant to the existing ERRA process because PG&E currently discusses expected monthly load migration with CCAs during the ERRA meet and confer process.[63]

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[60] Energy Division Track 3 Proposal at 17.

[61] CalCCA Proposal at 3-4.

[62] Cal Advocates Opening Comments at 3.

[63] PG&E Reply Comments at 4.

Given the complexity of the forecasting process and the expected proliferation of LSEs, the Commission agrees it is appropriate to direct LSEs that expect load migration to undertake good-faith attempts to meet and confer with their LSE counterparts (that is, those LSEs they will lose load to, or those LSEs they will gain load from) prior to filing initial year ahead forecasts. However, the Commission seeks to avoid an unduly burdensome or prescriptive process at this time, particularly in consideration of IOUs and some CCAs that may require more meetings than other LSEs.

To that end, we adopt a meet and confer requirement whereby: (1) a meeting between LSEs that anticipate load migration shall occur reasonably in advance of the filing deadline for initial year ahead forecasts (April of Year 1), and (2) in each LSE's initial year ahead forecast filing, each LSE shall briefly describe the dates of meetings with other LSEs to discuss load migration, any agreements, and any continued areas of disagreement. For the purposes of this requirement, we define "agreement" to mean: where two LSEs that expect load migration between themselves shall adjust their forecasts by the same MW amount, regardless of whether their respective forecasting methods are identical. We decline to otherwise specify where and how the meetings shall occur.

Further, we do not adopt penalties at this time for LSEs that fail to satisfy the meeting requirement prior to filing their initial year ahead forecasts. However, existing penalties in the RA program may apply if it becomes apparent that a failure to satisfy the requirement was made in bad faith.

Lastly, we expect this supplemental meeting information to serve as useful context for the CEC and Energy Division to identify discrepancies between forecasts. We direct Energy Division to work with the CEC on any necessary updates to filing templates.

3.5.4.2. Data Transfer Process

Energy Division offers a proposal to standardize data transfer and handling between IOUs and non-IOU LSEs. Energy Division proposes the following:

(1) CCAs and ESPs must request from IOUs any load data they will use in developing year ahead forecasts by January 15 of a given year (the year prior to the year for which they are developing forecasts);

(2) IOUs must provide CCAs and ESPs with the requested load data by March 1;

(3) At a minimum, the load data IOUs provide will include three years of hourly meter data for each individual account in each jurisdiction requested by the given ESP or CCA. The three years of data should include the three years immediately preceding the year in which the IOU provides the data (*e.g*. the IOU would provide data for 2018-2020 pursuant to a request in 2021, which the CCA or ESP would use to develop its 2022 year ahead load forecast). The data should also indicate the rate class for each account.[64]

In order to allow non-IOU LSEs to obtain the requisite data to develop their initial load forecasts, we agree that Energy Division's data sharing proposal will improve the efficient and effective transfer of data between all LSEs. However, we adopt the proposal with modifications to Item 3, as follows:

(3) At a minimum, the load data IOUs provide shall include the following:

a. Hourly meter data for the previous year for each individual account in each jurisdiction requested by a given ESP or CCA, and

b. Hourly meter data for at least the two years preceding the previous year for each individual account in each

[64] Energy Division Track 3 Proposal at 18.

> jurisdiction requested by a given ESP or CCA, excluding any data that the IOU provided to the same ESP or CCA in an earlier year that has not been corrected or otherwise updated since that earlier provision.

For example, pursuant to a request in 2021 (which the LSE would use to develop its 2022 year ahead forecast), the IOU shall provide 2020 historical data for all requested accounts and 2018-2019 data for all requested accounts that it has not previously provided to the LSE, or that has been previously provided but has since been updated. The data shall also indicate the rate class for each account.

The Commission notes that it is the responsibility of a non-IOU LSE to request data for the jurisdictions it intends to serve, but that an IOU shall make reasonable efforts to track which previously-provided data has been updated. The Commission recognizes that the IOUs will require additional time to implement the adopted data transfer schedule and update their respective data structures. To provide reasonable lead time for implementation, the Commission expects the requisite updates to be implemented on or about January 2021, in advance of the 2022 year ahead load forecasting process.

3.5.4.3. Conflict Resolution

Energy Division proposes that for any conflicts or discrepancies that exist at the time of an LSE's filing its initial year ahead load forecast, the CEC and Energy Division staff will attempt to resolve the issues through individual LSE discussions and/or requests for additional data. If these efforts are unsuccessful 30 days prior to the date in which the CEC and Energy Division must provide

LSEs with their initial year ahead requirements, the CEC and Energy Division will allocate the differential pairwise between the affected LSEs.[65]

CalCCA and PG&E support this proposal, although comment that the meaning of "pairwise" is unclear.[66] CalCCA instead proposes "allocating the differences to the disputing parties in proportion to their relative loads."[67] AReM supports this proposal but notes that it does not give LSEs a resolution opportunity if the LSE "disagrees with a plausibility or pro rata adjustment made by the CEC to the LSE's initial or final forecast." AReM requests that LSEs have an opportunity to request the detailed basis for any CEC adjustments, and have an opportunity to contest those adjustments.[68]

We agree that Energy Division's proposal is a reasonable mechanism to attempt to resolve discrepancies between LSEs prior to filing initial year ahead forecasts. We clarify the definition of "pairwise" to mean: between two (or more) LSEs that have the opportunity to serve the load at issue. For example, if an unresolved dispute arises over whether 50 MW of customer load will be served by a CCA or the local IOU, the CEC will allocate the 50 MW between the CCA and IOU, and will not spread that amount among any other LSEs in the TAC area. Accordingly, with the above clarification, we adopt Energy Division's conflict resolution proposal.

3.5.5. Timeline for Implementation of Changes

AReM requests clarification as to which of Energy Division's proposed forecasting changes begin during the 2020 year ahead forecasting process versus

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65 *Id*.

66 PG&E Opening Comments at 15, CalCCA Opening Comments at 7.

67 CalCCA Opening Comments at 7.

68 AReM Opening Comments at 4.

the 2021 year ahead process.[69] Due to the timing of the proposed decision in Track 3, many of these changes cannot be implemented for the 2020 year ahead process. The Commission believes it is appropriate to apply the definition of load migration (adopted in Section 3.5.1.1), the rule that load migration is the only allowable reason for differences between initial and final year ahead load forecasts (adopted in Section 3.5.1.1), and the conflict resolution process (adopted in Section 3.5.4.3), immediately upon the date of this decision. The Commission applies all other forecasting changes adopted above in Section 3.5to begin in the 2021 RA compliance year.

3.6. Qualifying Capacity Methodology

Several parties propose methodologies for determining the qualifying capacity (QC) and effective flexible capacity (EFC) values for resources which are aggregates of several generator types.

3.6.1. Counting Methodologies for Combined Resources

SCE proposes multiple counting conventions that vary depending on the type and dispatchability of the combined resources. In the case of a dispatchable battery combined with a dispatchable generating resource, SCE proposes that the QC value be calculated as the sum of the QC of the two parts. For a fully dispatchable and deliverable battery plus a non-dispatchable renewable resource, SCE proposes that the QC be the ELCC of the renewable resources plus the maximum output of the battery under four-hour discharge and the EFC would be the flexible capacity of the battery, or, if the renewable resource was curtailable, the sum of the EFCs for the renewable resource and the battery.[70]

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[69] *Id*. at 2.

[70] SCE Proposal at 5.

SCE proposes a valuation methodology for combinations of dispatchable batteries and demand response, as combinations of other dispatchable generators with the exception that the combined resource must follow the requirement that DR resources may not export energy to the grid.[71] Similarly, PG&E proposes that combinations of traditional DR and storage should be measured in aggregate using relevant measuring methodologies.[72]

Several parties support SCE's methodology for developing qualifying capacity for resources that combine storage with other generators, including the Joint Environmental Parties, CalWEA, Middle River and the Joint DR Parties. CESA and LSA recommend that an ELCC value for combined solar and storage resources should be developed.[73] PG&E, CLECA, and the CAISO find merit in SCE's proposal but state that a working group is needed to further vet and develop the proposal.[74]

We decline to adopt a combined QC value for a dispatchable battery combined with a dispatchable generating resource, or a dispatchable battery combined with a renewable resource at this time. The Commission appreciates the potential benefits of "plus solar" resources and the financial considerations that would encourage development of combined battery and renewable resources. However, a combined QC value raises many questions that we are unable to answer at this time. We encourage parties to discuss potential counting methodologies and modeling parameters in the ELCC working group designated in Section 3.7.2 below.

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[71] *Id.* at 7.

[72] PG&E Proposal at 4.

[73] CESA Opening Comments at 4, LSA Opening Comments at 4.

[74] PG&E Opening Comments at 16, CLECA Opening Comments at 9, CAISO Opening Comments at 7.

While CESA, SCE and LSA support development of an ELCC value for a non-dispatchable battery combined with a renewable generator, we find that adoption of such an ELCC value is not feasible at this time. There are few, if any, such resources currently online and an infinite number of configurations that such resources could take on, which have not yet been fully considered. For example, if the system was sized such that the renewable generator only charged the battery, it appears that the reliability benefit of the combined resource would only be that of the battery. Such considerations ultimately make development of modeling assumptions about resource behavior and availability impracticable at this time.

For combinations of behind-the-meter batteries and traditional demand response, we conclude that a new methodology is unnecessary. A battery should only count at its maximum power plant output (PMax) if it is fully deliverable during the RA measurement hours. Where this is the case, application of the load impact protocols will result in the battery receiving its full value. In cases where it is not fully dispatchable, due to an inability to export energy, the QC value will be discounted appropriately. Therefore, the load impact protocols shall continue to be used to determine the QC value of utility demand response resources whether they are composed of batteries only, batteries and traditional customers, or traditional customers only.

3.6.2. Counting Methodologies for Hydro and Other Use-Limited Resources

PG&E proposes that the Commission should revisit the QC methodology for hydro resources to develop a "comprehensive approach for hydro resources that balances hydrological conditions, weather patterns, FERC licensing, storage levels and upstream and downstream powerhouses…"[75]

PG&E recommends that in the year ahead timeframe, the scheduling coordinator should provide a monthly QC based on resource-specific modeling. For month ahead showings for compliance, the QC value would remain the same as the value on the year ahead showing.[76] However, a different "operational QC" would be used to set the CAISO RA obligations and performance assessment and would be subject to change based on new information such as changes in hydro forecasts or storage levels. PG&E claims that individual resource modeling is needed due to variations in flow restrictions and design limitations while an operational QC is necessary to ensure reliability and maximize resource value since hydro conditions and outages vary widely and may not be predictable.[77]

PG&E also proposes that a similar methodology may be appropriate for use-limited dispatchable fossil resources.[78] In this case, the resources would receive a QC value of PMax in the year ahead timeframe, but in the month ahead timeframe, while compliance QC would remain unchanged, operational QC would be subject to decrease based on the CAISO dispatches of the resource to date, resource-specific modeling produced by the scheduling coordinator and operator/schedule adjustments. PG&E suggests that this methodology would allow for conservation of start-ups in off-peak months in order that adequate

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[75] PG&E Proposal at 10-11.

[76] PG&E Opening Comments at 4.

[77] *Id*. at 4-5.

[78] *Id*. at 5-6.

start-ups would be available during peak months when they are most needed.[79] PG&E proposes that the Commission create a working group to examine the relationship between local RA requirements and RA resource obligations, including how requirements are determined, how performance is assessed, and how backstop procurement occurs.[80]

SDG&E supports PG&E's proposal since NQC values of local resources cannot be decreased after the year ahead showings which occurs before critical information on water availability is known.[81] While Calpine generally supports modifications to the QC methodology to reflect the availability of water and other potential constraints on hydro generation, it does not support having separate compliance and operational QC values since QC should reflect a resource's capability to perform.[82] The CAISO supports exploring updates to the methodology but believes the record is not robust enough to adopt the methodology at this time.[83]

The Commission concludes that it is appropriate to revisit the counting methodology for hydro and use-limited fossil resources. Variability in water availability makes predicting true generation capability of a hydro resource difficult in the year ahead timeframe. Additionally, both use-limited fossil resources and hydro resources, while able to generate at PMax, cannot do so at all times. The Commission recognizes the importance of allowing bidding behavior that maximizes the value of the resources and ensures their availability

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[79] *Id.*

[80] *Id.* at 7.

[81] SDG&E Opening Comments at 16.

[82] Calpine Opening Comments at 10.

[83] CAISO Opening Comments at 6.

when they are most needed to meet grid reliability needs. While this may mean that functionally a resource has an "operational QC" that is below PMax, this would likely be difficult to implement.

The Commission agrees with parties that a working group is needed to further evaluate and develop PG&E's proposal. We direct Energy Division to convene a working group on counting methodologies for hydro and use-limited fossil resources with the expectation that the group will submit a proposal into the RA proceeding in early 2020.

3.6.3. Counting Methodologies for Third-Party Demand Response

D.16-04-045 granted an exemption from the load impact protocols for all third-party demand response (DR) resources for the 2017 – 2019 RA compliance years. PG&E and SCE propose that load impact protocols should be used to calculate the QC of third-party DR resources.[84] As this exemption is expiring as of the 2020 RA compliance year, the Commission agrees that all demand response resources, whether third-party or IOU-managed, should receive QC values based on application of the load impact protocols unless or until a further exception is established.

Additionally, in Application (A.) 17-01-012, a proceeding addressing the Demand Response Auction Mechanism (DRAM), a proposed decision was issued on May 31, 2019 that addresses a method for determining the QC value of DRAM resources.[85] The Commission recognizes that QC values are typically raised in the RA proceeding; however, the proposed decision in A.17-01-012 addresses the limited issue of QC values for DRAM resources during the DRAM pilot. To the extent that the Commission adopts a method for determining the

[84] PG&E Proposal at 4, SCE Proposal at 8.

[85] *See* Proposed Decision, A.17-01-012, issued May 31, 2019.

QC values for third-party DRAM resources in A.17-01-012, the adopted method is applicable to the RA program and should be implemented by Energy Division for the period of the DRAM pilot. Any further refinements to the method for allocating the QC values for DRAM, or other DR resources, will be addressed in a future phase of the RA proceeding.

3.7. Effective Load Carrying Capacity

In D.17-06-027, the Commission adopted an Effective Load Carrying Capacity (ELCC)[86] methodology. The ELCC values adopted in 2017 were designed to back out the effect of behind-the-meter (BTM) solar from the ELCC calculation, and also to mitigate losses of capacity credit for solar that had been caused by a transition from an exceedance method to an ELCC-based method.[87] However, D.17-06-027 did not mandate the use of a particular model for ELCC determinations going forward, acknowledging that "changes, improvements and refinements [were still] needed."[88] Appendix A to D.17-06-027 lists a series of steps that summarize how Energy Division performed the ELCC calculations in 2016.

In Track 1 of this proceeding, Energy Division and parties raised several proposals to revise and improve the ELCC calculation and to account for the increased amount of solar and wind generation, as well as energy storage, on the

[86] Also referred to as Effective Load Carrying Capability. ELCC is a statistical modeling approach to determine the capacity value of different resources relative to "Perfect Capacity." Perfect Capacity refers to fictional generators created in a production cost model that have perfect capabilities, such as zero forced and maintenance outage rates and zero startup times, and serve as a standard against which to compare real existing generators. For example, if removing 100 MW of solar resources from the grid and replacing it with 50 MW of perfect capacity results in no change in the Loss of Load Expectation, the ELCC of the solar resources would be 50 percent.

[87] D.17-06-027 at 20.

[88] *Id.*

grid. In D.18-06-030, the Commission acknowledged the complexity of these issues, as well as the need to adequately understand the ramifications of modifying the ELCC modeling.[89] The Commission directed Energy Division to conduct more granular ELCC studies to understand these issues, to hold workshops, and to submit a proposal in this proceeding for consideration, as necessary.[90]

Energy Division submitted a revised ELCC proposal, served by the ALJ's ruling on February 13, 2019 (Revised ELCC Proposal). To determine the effect of storage on the ELCC of wind and solar generators, Energy Division conducted an analysis of dispatch patterns from runs of its production cost model. Energy Division followed the same series of steps as outlined in D.17-06-027 with one proposed change regarding how to allocate the diversity benefit for storage. Energy Division found that storage primarily increases the value of solar, as it tends to charge during periods of solar overgeneration (thus absorbing excess solar generation and allowing some of the solar generation to reduce loss-of-load later in the day) and discharge when the system has a higher need for energy.[91] Based on the simulation of expected hourly generation dispatch on an average spring day, storage charging times closely corresponded with excess solar production.

Based on its analysis, Energy Division proposes allocating the diversity benefit caused by charging and discharging of storage to in-front-of-the-meter solar generators. Diversity benefit is created when a diverse set of reliability risks are met by multiple generators operating concurrently, and when they

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[89] D.18-06-030 at 38-39.

[90] *Id.*

[91] Energy Division Revised ELCC Proposal at 10.

together provide greater benefit than any one individually would have provided. In this case, according to Energy Division, solar resources are more valuable since there is storage to absorb the energy and make it available later in the evening.

3.7.1. Comments

Several parties support Energy Division's revised ELCC proposal, including LSA, Middle River, WPTF, and CESA, although some support it on an interim basis. LSA states that the proposed methodology "appropriately identifies the contribution of [grid-interconnected solar] resources to grid reliability."[92] Middle River supports the proposal but recommends an annual recalibration of the ELCC calculation given the fluctuating resource combination.[93] CESA supports a one-time ELCC adjustment, but states that the Commission "should reward project developers for building the kinds of resources that the grid needs to maintain reliability – *i.e.*, energy storage resources paired with solar, wind and thermal generators to reduce renewable intermittency and grid congestion."[94] CESA contends the proposal is "only viable due to the recency of the ELCC calculation and the Commission's willingness to maintain the full RA value for existing energy storage."[95] WPTF recommends an ongoing reexamination of the ELCC methodology every two years to ensure the resulting values reflect ongoing changes to California's generation resource portfolio.[96]

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92 LSA Opening Comments at 1.

93 Middle River Opening Comments at 4.

94 CESA Opening Comments at 5.

95 *Id*.

96 WPTF Opening Comments at 3.

CalWEA offers conditional support for allocating the diversity value of storage to solar resources, if the Commission also "properly aligns flexible-RA requirements with the need for flexible resources as they are caused by LSEs."[97] CalWEA proposes that "LSEs whose supply portfolios do not match their loads should be responsible for paying more for system integration resources, such as storage resources, than those whose portfolios better match their loads."[98]

Some parties recommend modifications to the proposal. PG&E, WPTF, and the CAISO together advocate for prioritizing and incorporating BTM solar resources into the ELCC analysis on par with in-front-of-the-meter solar, in order to improve the methodology and accuracy of the results.[99]

Other parties express concern with the proposal. SCE strongly cautions against transferring storage-enabled benefits to wind or solar resources, as this may overstate the reliability values of those resources. SCE also states that the diversity benefit is already captured in the QC assigned to the storage resource.[100] LS Power criticizes the logic of transferring benefits from one resource type that has invested capital to achieve a market benefit (*i.e.*, storage) to another resource that has not (*i.e.,* solar or wind).[101] Wellhead states it is a distortion to allocate a portfolio benefit to a particular class of resources.[102]

PG&E states that Energy Division's method for surfacing a Loss of Load Expectation (LOLE) in months when there is a robust amount of system capacity

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[97] CalWEA Opening Comments at 3.

[98] *Id*.

[99] PG&E Proposal at 2, WPTF Opening Comments at 2, CAISO Opening Comments at 4.

[100] SCE Opening Comments at 13.

[101] LS Power Opening Comments at 1-2.

[102] Wellhead Opening Comments at 4.

results in assigning unusually high ELCC values to storage in those months.[103] NRG argues the proposal to assign all the diversity benefit to solar be contextualized given that during hours 10-16 (in which storage is likely to be charging), solar provides a relatively modest amount of total energy relative to total energy production. NRG asserts that the ELCC analysis "cannot evolve to a point that it produces capacity values that guarantees variable resources will be producing energy at that capacity value when the peak demand, or peak reliability need, is occurring."[104]

Other parties question the modeling inputs used in Energy Division's methodology and request additional analysis of the proposal, including Cal Advocates, CLECA, PG&E, SDG&E and TURN.[105] PG&E and TURN comment that the modeling of storage, including the impact of the removal of PG&E's Helms Pumped Storage Plant, needs further review before concluding that storage provides such high reliability benefits.[106] Both advocate for greater transparency and documentation of the ELCC computations and findings in the future, including additional workshops.[107]

3.7.2. Discussion

We first note that multiple parties encourage reconsideration of policy decisions made in D.17-06-027 when the Commission declined to apply ELCC calculations to BTM photovoltaic (PV). The Commission rationalized this determination because the RA program currently does not give credit to any

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[103] PG&E Opening Comments at 22.

[104] NRG Opening Comments at 6-7.

[105] Cal Advocates Opening Comments at 13, CLECA Opening Comments at 11-15, PG&E Opening Comments at 21, SDG&E Opening Comments at 4, TURN Reply Comments at 2-3.

[106] PG&E Opening Comments at 22, TURN Reply Comments at 2-3.

[107] *Id.*

BTM resources and doing so would force a restructuring of the RA program. At this time, the Commission declines to reconsider our previous decision with respect to BTM PV.

However, we do agree that BTM PV has a pronounced effect on the ELCC of wind and solar resources (with nearly 10,000 MW of BTM PV resources installed by 2020).[108] LOLE risk that usually occurred at times of peak electric demand when electric capacity is operating at full is now satisfied by solar generation, both in front of and behind the meter. LOLE risk is thus more prevalent in later times of the day, when in-front-of-the-meter solar resources cease to generate as the sun sets. The proposed ELCC values now implicitly incorporate (not explicitly through RA credit for BTM PV) the effect of BTM PV, which is why the overall solar ELCC values have declined since the 2017 results adopted in D.17-06-027.

Regarding PG&E's comments as to the method for surfacing a LOLE in months where there are robust system capacity amounts, while the Commission seeks the most accurate and fair allocation of capacity value, PG&E's concerns appear to stem from an objection to the method adopted in D.17-06-027. That decision established a series of steps and the first step is the method adopted to arrive at a baseline out of which wind, solar, and now storage facilities are removed in order to assess ELCC in all 12 months.[109] The Commission declines to modify that aspect of the methodology at this time.

Weighing parties' comments and concerns, the Commission ultimately finds that the revised ELCC proposal appropriately identifies the contribution of

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[108] *See e.g.,* Energy Division's Proposal for Monthly Loss of Load and Solar and Wind Effective Load Carrying Capability Values, R.14-10-010, issued March 23, 2017.

[109] D.17-06-027, Appendix A, at A4.

in-front-of-the-meter solar resources to grid reliability and reasonably captures the interaction effect between solar and storage. Energy Division's proposal makes changes to Step 4 of the methodology used in 2017, regarding allocating the diversity benefit to resource types that are already at 100 percent ELCC in standalone studies.[110] This change allocates diversity first to resources that are not at 100 percent in standalone studies, and then to resources that seem to cause the most diversity benefit, and ensures that diversity benefit.

Some parties comment that storage may charge off dispatchable generators and therefore all resources should receive some of the diversity benefit.[111] While storage may charge off dispatchable generators, such as combined cycle generators or nuclear generators that are unable to fully shut off in periods of over-generation, both combined cycle generators and nuclear generators have QC values equal to their maximum generating capacity. Therefore, as with storage generators, allocating diversity benefit to them is not appropriate as it would give a resource ELCC or QC greater than 100 percent of their maximum generating capacity or nameplate. This would translate to a situation where an existing generator would be able to more easily offset LOLE than Perfect Capacity.

The Commission concludes that calculating solar ELCC on a supply-side basis, rather than including BTM solar in the calculation, is reasonable and aligns with generally accepted ELCC methodologies adopted in D.17-06-029. Accordingly, we adopt Energy Division's revised ELCC proposal, and the numbers resulting from the proposal, as the approved ELCC factors to use for

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[110] *Id*.

[111] *See, e.g.*, Calpine Opening Comments at 1, CAISO Opening Comments at 3, WPTF Opening Comments at 3.

establishing the QC values for wind and solar supply-side resources in the RA proceeding. These factors are set forth in Appendix A. We adopt these factors for use for the 2020 RA compliance year.

The Commission recognizes the numerous comments regarding the ELCC methodology used by Energy Division, and that there is no industry standard methodology for conducting ELCC assessments where such a large solar penetration is present with a growing fleet of storage resources. The Commission also acknowledges comments that additional transparency with respect to the ELCC methodologies is warranted. We do note that the source data used for conducting Energy Division's ELCC studies is publicly available on the Commission's website[112] but that more stakeholder engagement may be necessary.

Given parties' comments, and the dynamic nature of California's energy fleet, the Commission directs Energy Division to continue to monitor and review the ELCC methodologies and identify factors that may require subsequent ELCC studies and refinements, such as further growth in wind and solar generation or additional storage resources being added to the grid. Additionally, we direct Energy Division to convene a workshop on ELCC methodologies, in particular on the disaggregation into locational or technology factors, additional work to incorporate storage into the methodology during the remainder of 2019, and ELCC for combined resources. This workshop should facilitate discussion of ELCC methods and explore additional relevant topics for the following RA compliance year.

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[112] http://www.cpuc.ca.gov/General.aspx?id=6442451973.

3.8. Path 26 Constraint

In D.07-06-029, the Commission identified transmission constraints in two zones surrounding Path 26: North of Path 26 (PG&E's TAC) and South of Path 26 (SCE and SDG&E's TACs). The Commission adopted the current Path 26 counting constraint, after recognizing that Path 26 may be over-relied upon by individual LSEs in their RA filings. The Path 26 constraint effectively limits the amount of capacity an LSE can procure on one side of Path 26 to serve load on the other side.[113] In D.17-06-027, the Commission considered the removal of the Path 26 constraint, which was proposed by PG&E as no longer relevant and fair. The CAISO opposed the removal of the constraint, arguing it was still necessary and relevant for the same reasons as it was originally intended.[114] The Commission ordered a working group to study the potential removal of the Path 26 constraint and its impact on reliability and to submit an analysis and recommendation into the RA proceeding.[115]

Energy Division states that it held a workshop to analyze "whether it was possible to exceed Path 26 constraints given the 2017 RA requirements and resources shown in North or South of Path 26." Energy Division conducted an analysis that revealed that Commission-jurisdictional LSEs have not exceeded their collective Path 26 allocations in the past few years.[116] Energy Division further analyzed the capacity available to all LSEs in the CAISO footprint and of the likelihood that LSEs' procurement could exceed the Path 26 constraints in worst-case scenarios. Based on its analysis, Energy Division believes that

[113] D.07-06-029 at 10-13.

[114] *Id*. at 23.

[115] *Id*. at 24.

[116] Energy Division Track 3 Proposal at 29.

physical violations of the Path 26 allocations are unlikely and largely dependent on three extreme scenarios: (1) where LSEs south of Path 26 procure only a minimum amount of capacity south of Path 26, (2) where LSEs south of Path 26 procure an average or less-than-average amount of imports, and (3) where LSEs north of Path 26 procure a higher-than-average amount of imports.[117]

Energy Division therefore concludes that the Path 26 constraint is too restrictive and states that "eliminating the constraint would allow greater procurement flexibility for LSEs without substantially increasing the threat of violating constraints along Path 26." SCE also proposes the removal of the Path 26 constraint, stating that "it provides limited reliability benefits and is unnecessarily interfering with the ability of the LSEs to procure available resources at the lowest cost to customers."[118] Energy Division recommends to continue reviewing the potential for procurement activity each year that may violate Path 26 constraints.

CLECA, Cal Advocates, PG&E, and Shell support the removal of the Path 26 constraint.[119] AReM supports the removal, provided that the CAISO agrees with Energy Division's assessment.[120] The CAISO does not oppose removing the Path 26 constraint as long as resources necessary for grid reliability are procured and states that it will continue to show the minimum resource requirement North and South of Path 26 in the year ahead LCR report.[121] SDG&E does not support eliminating or modifying the constraint, stating that the proposal is

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[117] *Id.* at 33-34.

[118] SCE Proposal at 10.

[119] CLECA Opening Comments at 4, Cal Advocates Opening Comments at 11, PG&E Opening Comments at 11, Shell Opening Comments at 5.

[120] AReM Opening Comments at 14.

[121] CAISO Opening Comments at 12.

unnecessary, is incomplete in resolving concerns raised by the CAISO in 2017, and that Energy Division did not evaluate whether LSEs individually exceeded Path 26 constraints.[122]

In consideration of the support for SCE and Energy Division's proposal, the Commission adopts the proposal to eliminate the Path 26 constraint effective upon the date of this decision. The Commission directs Energy Division to continue reviewing the potential for procurement activity that may violate Path 26 constraints.

3.9. Availability Limited Resources

The CAISO defines availability-limited resources as "those resources that have significant dispatch limitations such as limited duration hours (*e.g.*, per year, season, month, or day) or event calls (*e.g.*, per year season, month or consecutive days) that would limit the resources' ability to respond to a contingency event within a local capacity area."[123] This definition is limited to resources that count towards meeting local capacity area needs.

By contrast, the RA program is based on meeting a peak capacity requirement defined in megawatts without consideration of other resource availability needs. The CAISO cites the example where a 10 MW/40 MWh resource has the same RA value as a 10 MW/80 MWh resource. However, if a local capacity area requires 10 MW of capacity for an eight-hour period, only the latter resource can meet the reliability need. But under the RA program, the two resources receive equivalent RA value because of the RA program does not consider availability limitations.[124]

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[122] SDG&E Opening Comments at 7-8.

[123] CAISO's Track 2 Proposal, Chapter 6 at 1.

[124] *Id*. at 2.

The CAISO clarifies that it is not proposing specific or new requirements but requests the Commission "to acknowledge the local area capacity issue and begin vetting and developing new procurement guidelines that take into account local area load profiles and the energy-serving capabilities of local resource adequacy resources."[125] The CAISO adds that "[a]s the next step in this process, the CAISO will test the local resource adequacy portfolios to ensure they meet applicable reliability criteria during identified contingency events. … The CAISO will alert stakeholders if there is a deficiency in the ability of a local resource adequacy portfolio to serve load."[126]

The Commission agrees it is important to consider availability limited resources, particularly when constructing new resources. However, availability limited resources are very specific since needs vary significantly between local areas and sub-areas. The Commission plans to work closely with the CAISO to ensure that availability needs are met in all local reliability areas.

4. Comments on Proposed Decision

The proposed decision of ALJs Allen and Chiv in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on June 13, 2019 by the following parties: AReM, CalCCA, Calpine, CalWEA, CEERT, CESA, CAISO, CLECA, GPI, the Joint DR Parties, Marin Clean Energy and Sonoma Clean Power Authority (collectively, the Joint CCAs), NRG, PG&E, SDG&E, SCE, Sunrun, and TURN. Reply comments were filed on June 18, 2019 by AReM, CAISO, Cal Advocates, CEERT, CESA, CLECA, NRG, PG&E, and SDG&E.

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125 CAISO Reply Comments at 5.

126 *Id.*

All comments and reply comments have been carefully considered. We do not summarize every comment but rather, focus on major comments made in which the Commission did or did not make revisions in response to party input. However, additional changes have been made to the proposed decision in response to comments that may not be discussed here.

A few parties, including PG&E, SDG&E and CLECA, comment that the proposed decision fails to address QC for third-party DR resources despite being scoped into Track 3 of this proceeding. SDG&E comments that both PG&E and SCE proposed the use of load impact protocols to calculate the QC of third-party DR programs and that the decision should be modified to adopt this proposal. PG&E comments that numerous parties responded to this proposal during the proceeding. PG&E also notes that on May 31, 2019, the Commission issued a proposed decision in the DRAM proceeding, in A.17-01-012, that adopts a solution for determining the QC value for DRAM.

CLECA, SDG&E and PG&E state that the RA proceeding is the appropriate proceeding for determining the QC value for DR resources. We agree that the QC for third-party DR should be addressed in this rulemaking and that there is sufficient record to adopt PG&E and SCE's proposal. We have modified the proposed decision to reflect this. We have also added language to clarify the DRAM solution addressed in the proposed decision in A.17-01-012.

Multiple parties commented on the ELCC methodology adopted in the proposed decision. Several parties, including CLECA, CESA, CEERT, and CAISO, state that the ELCC methodology should be interim for the 2020 RA compliance year only. Others, including SDG&E and Sunrun, comment that ELCC values should be adopted for BTM PV resources. A few parties reiterate concerns with the ELCC methodology that were raised during the proceeding.

As discussed in the proposed decision, the Commission recognizes the need for further review of the ELCC methodologies and consideration of factors that may require subsequent ELCC studies and refinements. Therefore, we directed Energy Division to convene a workshop on ELCC methodologies. We encourage parties to participate in that workshop to discuss ELCC methods and explore other relevant topics.

SDG&E and PG&E comment that the decision should address PG&E's proposal to require LSEs to submit multi-year load forecasts for the multi-year local RA program adopted in D.19-02-022. The Commission acknowledges that this issue should be addressed. However, as stated in the Amended Scoping Memo issued on January 29, 2019, the issues scoped into Track 3 included issues "other than issues related to the multi-year and central buyer local RA program."[127] As further stated in D.19-02-022, the Commission "intends to revisit the LSE-based component of multi-year local procurement in a decision to be issued in the fourth quarter of 2019."[128]

SCE comments that as the proposed decision declines to adopt a waiver process for system and flexible RA, there is a need for a limited system and flexible RA waiver "to address situations where an LSE acting as the POLR (currently the IOUs) is required to serve unplanned load. In circumstances where the capacity price for system or flexible RA increases, LSEs that are not the POLR have the option of avoiding such high costs by returning the load to the POLR or declining to serve the load…This option is not available to the POLR."[129] SCE contends that the lack of a waiver, and the potential for unplanned load on the

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[127] Amended Scoping Memo at 2.

[128] D.19-02-022 at 29.

[129] SCE Comments on Proposed Decision at 3.

POLR, is problematic and costly for the POLR. We acknowledge SCE's concern but due to a lack of record support at this time, the Commission declines to modify the decision. However, we encourage SCE to raise this proposal in a later phase of the proceeding.

PG&E comments that the adopted BNI process may not sufficiently address implementation plans that are non-binding, creating a situation where an LSE may accelerate enrollment of customers earlier than announced in its implementation plan and the IOU must bear the higher RA requirement. SCE comments that under the adopted BNI process, an LSE may be able to add incremental load beyond its initial year ahead forecast, avoiding RA obligations for the added load since only the initial year ahead forecast is binding.

The Commission notes that in D.18-06-030, we adopted the requirement that LSEs are required to participate in all aspects of the year ahead load forecasting process for load they plan to serve in the following year. We find that an acceleration of enrollment beyond what is reflected in an LSE's year ahead forecast contradicts that requirement, as the LSE will not have fully participated in the year ahead forecast for the months where load increases. Thus, we find that the potential issue raised by SCE and PG&E is not permissible under the current RA program.

AReM comments that the use of the term "Binding Notice of Intent" process is misleading since that term has historically been associated with the process by which CCAs notify certain IOUs and the Commission of their future plans to serve load. AReM states the use of the BNI in the context of CCA notifications involve many requirements unrelated to RA load forecasting and proposes that the process be renamed "Binding Forecast" process to avoid confusion. PG&E agrees with AReM's recommendation but suggests use of the term "Binding Load Forecast" instead. The Commission agrees that the use of the BNI term may cause confusion and modifies the term in the proposed decision to Binding Load Forecast.

NRG comments that the proposed decision declines to adopt SCE's proposal to set a combined QC value for dispatchable battery plus a dispatchable generating resource, but the proposed decision's subsequent discussion "appears to implicitly approve a proposal it explicitly declined to approve." We have modified the decision to clarify this point.

AReM seeks clarification on the implementation timeline for the adopted adjustments to the load forecasting requirements. The decision has been modified to clarify the implementation timeframe.

5. Assignment of Proceeding

Liane M. Randolph is the assigned Commissioner and Peter V. Allen and Debbie Chiv are the assigned Administrative Law Judges in this proceeding.

Findings of Fact

1. The CAISO recommended the existing capacity needed for all local areas is 23,643 MW for 2020, 23,635 MW for 2021, and 22,598 MW for 2022.

2. It is reasonable to convene a working group to evaluate the LCR process prior to the development of the 2021-2023 local RA requirements.

3. The CAISO recommended system-wide flexible capacity requirements ranging from 11,812 MW in July to 18,025 MW in February.

4. In D.06-06-064, the local waiver trigger price was adopted. An updated trigger price to reflect current market conditions is warranted.

5. If the local trigger price is updated, it is appropriate to raise the local RA penalty price to the equivalent local trigger price value.

6. It is reasonable to establish a transparent, formal local waiver review process, in light of the recent increase in local waiver requests.

7. In D.14-06-060, the Commission adopted flexible RA capacity requirements but did not explicitly address the penalty structure for LSEs that incur both flexible and system RA deficiencies.

8. In order to develop accurate load forecasts for aggregation and comparison purposes, it is critical to standardize the assumptions used to develop initial and final year ahead load forecasts.

9. Energy Division's proposal for a Binding Load Forecast process will encourage effective forecasting in the year ahead process and discourage modifications to load forecasts for reasons other than unpredictable load migration.

10. Given LSEs' need to rely on investor-owned utilities as the source of customer-level load data for LSEs to develop their load forecasts, it is essential to establish clear data sharing and coordination guidelines.

11. Standardizing the data sharing process between IOUs and non-IOU LSEs will improve the efficient and effective transfer of data.

12. Energy Division's conflict resolution proposal is a reasonable mechanism to attempt to resolve discrepancies between LSEs prior to distributing initial year ahead requirements.

13. It is appropriate to revisit the counting methodology for hydro and use-limited fossil resources through a working group.

14. D.16-04-045 granted an exemption from the load impact protocols for all third-party DR resources for the 2017 – 2019 RA compliance years.

15. Given the transitional nature of the ELCC values adopted in D.17-06-027, it is reasonable to reconsider the ELCC modeling framework to include the effects of behind-the-meter photovoltaic generation.

16. Eliminating the Path 26 constraint may allow greater procurement flexibility for LSEs without significantly increasing the threat of violating constraints along Path 26.

Conclusions of Law

1. The CAISO's recommended LCR existing capacity needed for 2020 – 2022 should be adopted.

2. Energy Division should establish a working group to evaluate the LCR process prior to developing local RA requirements for the 2021-2023 compliance year.

3. The CAISO's recommended systemwide FCR figures for 2020 should be adopted.

4. Raising the local trigger price to an annualized value of the 85th percentile of the monthly local RA prices for South of Path 26 or $51/kW-year is a reasonable figure.

5. The local penalty price should be raised to match the local trigger price.

6. Local waiver requests should be submitted via a Tier 2 Advice Letter to promote transparency and establish a formal process.

7. Where an LSE incurs an equivalent system RA deficiency and flexible RA deficiency, the system RA capacity should be penalized at the system RA penalty price, with no separate penalty on the flexible deficiency.

8. Where an LSE incurs a flexible deficiency that exceeds its system deficiency, the system RA penalty price should apply for the system deficiency

and the flexible penalty price should apply to the flexible deficiency in excess of the system deficiency amount.

9. Load migration should be the only allowable reason for differences between initial and final year ahead load forecasts.

10. "Load migration" should be defined, for the purposes of the RA program, to mean load effects that: (1) result from one or more customers' retail electric service transferring directly from one LSE to another LSE in the same TAC area, and (2) an LSE cannot reasonably predict and include in an implementation plan or in an initial year ahead load forecast.

11. "Load migration" should not include the following non-exhaustive list of events: changes to approved implementation plans, changes to customer class load profiles, changes to weather assumptions, changes resulting from the receipt of new or updated customer meter data, new service requests, losses due to disconnects or *force majeure* events, transfers of load out of the TAC area, or forecasting errors.

12. Energy Division's proposal for a Binding Load Forecast process should be adopted.

13. A meet and confer requirement should be adopted whereby: (1) a meeting between LSEs that anticipate load migration shall occur in advance of the deadline for initial year ahead forecasts, and (2) in LSEs' initial year ahead forecast filings, LSEs should describe dates of meetings, any agreements, and any continued areas of disagreement.

14. Energy Division's proposal to standardize data transfer and handling should be adopted, with a modification to the proposed data provided.

15. Energy Division's conflict resolution proposal should be adopted.

16. Energy Division should convene a working group on counting methodologies for hydro and use-limited fossil resources.

17. Demand response resources, whether third-party or IOU-managed, should receive QC values based on application of the load impact protocols.

18. Energy Division's revised ELCC proposal appropriately identifies the contribution of in-front-of-the-meter solar resources to grid reliability and reasonably captures the interaction effect between solar and storage. Energy Division's proposed ELCC values should be adopted.

19. The Path 26 constraint should be eliminated.

O R D E R

IT IS ORDERED that:

1. The Commission approves 23,643 megawatts as the existing capacity needed for the Local Capacity Requirement for 2020.

2. The Commission approves 23,635 megawatts as the existing capacity needed for the Local Capacity Requirement for 2021.

3. The Commission approves 22,598 megawatts as the existing capacity needed for the Local Capacity Requirement for 2022.

4. Energy Division shall convene a working group to evaluate improvements and refinements prior to the development of the 2021-2023 local Resource Adequacy requirements.

5. The California Independent System Operator's recommended Flexible Capacity Requirement for 2020, ranging from 11,812 megawatts (MW) for July to 18,025 MW for February, shall be adopted.

6. The local Resource Adequacy (RA) waiver trigger price of $40/kW-year, adopted in Decision 06-06-064, shall be updated to the annualized value of the

85th percentile of the monthly local RA prices for South of Path 26, or $51/kW-year.

7. The local Resource Adequacy (RA) penalty price of $3.33/kW-month shall be raised to the equivalent value of the newly-adopted local RA trigger price, or $4.25/kW-month.

8. Local Resource Adequacy (RA) waiver requests shall be submitted via a Tier 2 Advice Letter to the Commission with accompanying service to the service list (in redacted form, if necessary) of the RA proceeding open at the time of the request.

9. We clarify that if a load-serving entity (LSE) incurs both flexible and system Resource Adequacy (RA) deficiencies, the penalty shall be based on the following:

a. Where an LSE incurs equivalent flexible and system RA deficiencies, the system RA penalty price shall apply.

b. Where an LSE incurs a flexible RA deficiency that exceeds its system RA deficiency, the system RA penalty price shall apply to the megawatt amount of the system deficiency and the flexible RA penalty price shall apply to the flexible deficiency megawatt amount that exceeds the system deficiency.

10. Load migration shall be the only allowable reason for differences between initial and final year ahead load forecasts. This modification shall be effective upon the date of this decision.

11. "Load migration" is defined, for the purposes of the Resource Adequacy program, as load effects that:

a. Result from one or more customers' retail electric service transferring directly from one load-serving entity (LSE) to another LSE in the same Transmission Access Charge area; and

b. An LSE cannot reasonably predict and include in an implementation plan or in an initial year ahead load forecast.

The adopted definition of "load migration" shall be effective upon the date of this decision.

12. "Load migration," for the purposes of the Resource Adequacy program, shall not include the following non-exhaustive events: changes to approved implementation plans, changes to customer class load profiles, changes to weather assumptions, changes resulting from the receipt of new or updated customer meter data, new service requests, losses due to disconnects or force majeure events, transfers of load out of the Transmission Access Charge area, or forecasting errors.

13. Energy Division's Binding Load Forecast proposal, as discussed in Section 3.5.3, is adopted. This adopted modification shall begin for the 2021 Resource Adequacy compliance year.

14. A meet and confer requirement is adopted whereby:

    a. A meeting between load-serving entities (LSEs) that anticipate load migration shall occur reasonably in advance of the filing deadline for initial year ahead forecasts, and

    b. In each LSE's initial year ahead forecast filing, each LSE shall describe the dates of meetings with other LSEs to discuss load migration, any agreements, and any continued areas of disagreement.

15. A modified version of Energy Division's proposal to standardize data transfer and handling is adopted, as follows:

    a. Community Choice Aggregators (CCA) and Electric Service Providers (ESP) must request from investor-owned utilities (IOU) any load data they will use in developing year ahead forecasts by January 15 of a given year (the year prior to the year for which they are developing forecasts);

    b. IOUs must provide CCAs and ESPs with the requested load data by March 1;

c. At a minimum, the load data IOUs provide shall include the following:

   i. Hourly meter data for the previous year for each individual account in each jurisdiction requested by the given ESP or CCA, and

   ii. Hourly meter data for at least the two years preceding the previous year for each individual account in each jurisdiction requested by the given ESP or CCA, excluding any data that the IOU provided to the same CCA or ESP in an earlier year and that has not been corrected or otherwise updated since that earlier provision.

These requirements shall begin for the 2022 Resource Adequacy compliance year.

16. Energy Division's proposal on conflict resolution, as discussed in Section 3.5.4.3, between load-serving entities is adopted. The adopted proposal shall be effective upon the date of this decision.

17. Energy Division shall convene a working group on counting methodologies for hydro and use-limited fossil resources.

18. All demand response resources, whether third-party or investor-owned utility-managed, shall receive qualifying capacity values based on application of the load impact protocols.

19. Energy Division's revised Effective Load Carrying Capacity (ELCC) proposal, as discussed in Section 3.7, and the resulting ELCC values shall be the approved ELCC factors in the Resource Adequacy program, as set forth in Appendix A. The adopted values shall be effective beginning with 2020 Resource Adequacy compliance year.

20. Energy Division shall convene a workshop on Effective Load Carrying Capacity methodologies.

21. The Path 26 constraint, adopted in Decision 07-06-029, shall be eliminated, effective upon the date of this decision.

22. Rulemaking 17-09-020 remains open.

This order is effective today.

Dated June 27, 2019, at San Francisco, California.

MICHAEL PICKER
President
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
Commissioners

Appendix A

Appendix A

Background on Modeling Processes Used to Create Monthly Effective Load Carrying Capacity Values

Monthly Effective Load Carrying Capacity (ELCC) studies are required to set the ELCC values of wind and solar electric generators. ELCC values based on a study of just the peak months are not sufficient to determine ELCC values for off-peak months. Monthly ELCC values rest on a baseline monthly Loss of Load Expectation (LOLE) or Loss of Load Hours (LOLH) study. LOLE and ELCC value of individual generators will differ each month, particularly for generators whose output is dependent on weather. The resulting performance of a portfolio of electric demand and electric generators will thus differ significantly between months of the year, and in each month the relative value of generators will also vary.

In this proceeding, Energy Division proposed to update the existing ELCC values for wind and solar generators, explicitly testing the ELCC of supply-side solar while leaving behind-the-meter (BTM) photovoltaic (PV) as a load modifier. In addition, Energy Division evaluated wind and supply-side solar alongside energy storage resources due to the interplay in value between the resources. The step-by-step process is described below.

Monthly ELCC Study Process:

Monthly ELCC studies are required to set the ELCC values of wind and solar electric generators applying to each month individually of the Resource Adequacy (RA) compliance year. ELCC values based on a study of just the peak months are not sufficient for this purpose, due to the highly variable ELCC value of these resources depending particularly in the case of solar and wind, on monthly patterns of electric demand and weather patterns. Monthly ELCC values rest on a baseline monthly LOLE or LOLH study. Other reliability metrics (such as Expected Unserved Energy or EUE) may be studied, but LOLE and LOLH will be the preferred means of assessing reliability.

Energy Division's proposed values (adopted in this decision) are highlighted in Table 1 below. This table is excerpted from Energy Division's revised ELCC proposal, dated February 13, 2019.

Table 1: Energy Division's Proposed 2020 ELCC values

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
R. 14-10-010 Previously Adopted Values	Wind	11%	17%	18%	31%	31%	48%	30%	27%	27%	9%	8%	15%
CPUC adopted values	Wind	14%	12%	28%	25%	25%	33%	23%	21%	15%	8%	12%	13%
R. 14-10-010 Previously Adopted Values	Solar	0%	2%	10%	33%	31%	45%	42%	41%	33%	29%	4%	0%
CPUC adopted values	Solar	4%	3%	18%	15%	16%	31%	39%	27%	14%	2%	2%	0%

Energy Division first performed a LOLE study to assess the baseline reliability of the overall electric system. Energy Division needed to surface LOLE events equally in each month in order to assess ELCC to meet reliability risk that results in that LOLE. Once monthly reliability baselines were studied and determined, Energy Division produced a study of the monthly ELCC value of the whole portfolio of electric generators in the class being studied (the Portfolio ELCC) to serve as a baseline control total for each subcategory or locational group within the larger portfolio being studied. The resulting Portfolio ELCC value is disaggregated into standalone ELCC values for each technology category based on subsequent standalone ELCC studies.

Standalone ELCC values are determined by studying one category or subcategory of electric generator at a time, and individually in each month. Standalone monthly ELCC values are totaled by month and the total is compared to the corresponding month's Portfolio ELCC, and the standalone values are either lowered or raised to equal the corresponding month's Portfolio ELCC. This is called the Diversity Adjustment.

Monthly ELCC of wind or solar generators in the California Independent System Operator (CAISO) area were established pursuant to the following steps:

1. Conduct a Monthly LOLE study, including projected loads and expected resources for that month targeting a desired monthly reliability level. Energy Division targeted a range of LOLE between 0.02 to 0.03 each month. If results are either more or less reliable than desired, capacity is to be added or subtracted until each month's reliability results are in the desired range.

2. Conduct a Monthly Portfolio ELCC study. Remove all wind, solar, and energy storage electric generation facilities inside the CAISO aggregated region. Then add Perfect Capacity in each month individually until the resulting LOLE results are again within the desired range. The amount of Perfect Capacity in megawatts (MW) added is equal to the Portfolio ELCC of all wind, solar and storage resources.

3. Perform ELCC modeling on each category individually.

    a. Put the wind and storage resources back and leave solar generators removed. Remove blocks of Perfect Capacity iteratively from each month until reliability levels are within the desired range. The result is the standalone ELCC of solar generators. Record the monthly levels of Perfect Capacity modeled.

    b. Perform Step A in reverse by adding back solar generators and removing wind generators. Remove blocks of Perfect Capacity iteratively from each month. Remove Perfect Capacity until the reliability level again falls within the desired range in each month. The result is the standalone ELCC of wind generators. Record the monthly levels of Perfect Capacity or added load modeled.

c. Finally perform the standalone ELCC study or storage resources by putting back wind and solar and removing storage. Remove or add blocks of Perfect Capacity iteratively from each month. Remove Perfect Capacity until the reliability level again falls within the desired range in each month. The result is the standalone ELCC of wind generators. Record the monthly levels of Perfect Capacity or added load modeled.

4. Add the standalone ELCC of wind, storage, and solar generators, and compare the total to the Portfolio ELCC calculated earlier. The difference (either positive or negative) is the diversity adjustment. The diversity adjustment will be negative when the standalone ELCC values total greater than the Portfolio ELCC, and positive when the standalone totals are less than Portfolio ELCC. This is the result of modeling an individual category of generator that provides benefit to another while another category of generator is still included. Some of the reliability contribution it imparts is applied as diversity.

   If it is found that any standalone ELCC study results in ELCC of 100 percent, and there are positive diversity adjustments to allocate, Energy Division will not allocate further ELCC diversity adjustment to the resource class. This would translate to a situation where an existing generator would more easily offset LOLE than Perfect Capacity. Energy Division will instead allocate the adjustment to resource classes with standalone ELCC values less than 100 percent and that can be determined to be most responsible for creating the diversity.

5. Use the ELCC MW amounts that represent the diversity adjusted Perfect Capacity equivalent amounts resulting from Step 4 and divide those MW amounts by the total nameplate installed MW of that technology, and the resulting monthly percentage values represent the ELCC percentages that are applied to the nameplate MW values of each individual generating facility to create the Qualifying Capacity of the generator.

6. Any further steps to create locational factors to break up wind and solar further into location or sub technology specific factors would follow from this point, and thus would be added as steps 7 and on. Future Monthly ELCC studies would require restarting the sequence of studies from Step 1.

(End of Appendix A)