COM/MP6/ilz **Date of Issuance: 6/3/2019**

Decision 19-05-043 May 30, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Senate Bill 237 Related to Direct Access	Rulemaking 19-03-009

DECISION REGARDING INCREASED LIMITS FOR DIRECT ACCESS TRANSACTIONS

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DECISION REGARDING INCREASED LIMITS FOR DIRECT ACCESS TRANSACTIONS

Summary

This decision implements a 4,000 gigawatt hour increase allowed for Direct Access transactions that will be apportioned for each respective Investor-Owned Utility's service territory. This decision also sets forth the procedures and timing for assigning the increase to eligible customers. The increase is implemented as authorized in accordance with the provisions of Senate Bill 237 (Stats. 2018, Ch. 600).

This decision adopts portions of the Commission Staff proposal for determining how the Commission should apportion the Direct Access increase, but modifies Commission Staff's proposal for determining the customers who are eligible for the increase by allowing customers to enroll pursuant to the Direct Access waitlists that are effective on January 1, 2019, and January 1, 2020, rather than only the waitlist that is effective for 2019. In addition, this decision adopts Commission Staff's proposal to delay the service date for customers who enroll in the DA expansion, but changes the earliest start date from January 1, 2020, to January 1, 2021, to better coordinate this expansion of DA and ensure compliance with the Commission's Resource Adequacy rules.

1. Background

On March 14, 2019, the Commission issued an Order Instituting Rulemaking (R.) 19-03-009, pursuant to Senate Bill (SB) 237,[1] which concerns Direct Access (DA) transactions. In R.19-03-009, Commission Staff proposed to (1) allocate the DA increase based on the proportion of each respective

[1] Stats. 2018, Ch. 600, amending Public Utilities (Pub. Uitl) Code section 365.1. All further statutory references are to the Pub. Util. §§ unless otherwise specified.

Investor-Owned Utility's (IOUs) eligible DA load to the statewide total DA load, (2) allow eligible customers who enroll in DA expansion to start service on January 1, 2020, and (3) require that IOUs enroll eligible customers using the DA waitlist that is effective as of January 1, 2019.[2] The Commission established a schedule that required comments on preliminary issues to be filed on or before April 5, 2019, with reply comments due on April 10, 2019. The schedule also noticed a prehearing conference, which was held on April 4, 2019, and a workshop, which was held on April 9, 2019.

Timely comments were filed by: Advanced Energy Economy (AEE) and The Advanced Energy Buyers Group (AEBG) (together, AEE/AEBG),[3] Alliance for Retail Energy Markets (AReM), Bear Valley Electric Service (Bear Valley), California Community Choice Association (CalCCA), California Large Energy Consumers Association (CLECA), Commercial Energy of California (Commercial Energy), Direct Access Customer Coalition (DACC), Energy Producers and Users Coalition (EPUC), Liberty Utilities LLC (Liberty), PacifiCorp d/b/a Pacific Power (PacifiCorp), Pacific Gas & Electric Company (PG&E), San Diego County Water Authority (SDWA), San Diego Gas & Electric Company (SDG&E), Shell Energy North America (US), L.P. (Shell Energy), Southern California Edison Company (SCE), The Regents of the University of California (UC). AReM, AEE/AEBG, CalCCA, CLECA, Commercial Energy, DACC, East Bay Community Energy (EBCE), Energy Users Forum, PG&E, SCE, SDG&E, Shell Energy, and 3 Phases Renewables Inc. filed reply comments.

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[2] *See* Order Instituting Rulemaking to Implement SB 237 Related to Direct Access, R.19-03-009 at 9-10 (March 29, 2019).

[3] AEE/AEBG filed joint comments.

On April 9, 2019, the Commission's Energy Division hosted a workshop to discuss Commission Staff's proposal, including the calculations supporting Commission Staff's methodology for apportioning the DA cap increase to the three large Investor-Owned Utilities (IOU) service territories.[4]

On April 17, 2019, the assigned Commissioner issued a scoping memo (Scoping Memo).

2. Issues Before the Commission

Pursuant to R.19-03-009, the issues before the Commission are as follows:

1. Whether the Commission should adopt Staff's proposal, noted below, or a different approach. Staff's proposal is as follows:
    a. The 4,000 gigawatthours (gWh) is apportioned as a percentage of the load for the full service territory of an IOU, excluding residential and existing DA load, irrespective of which load serving entity (LSE) currently serves the remaining load.
    b. To comply with year-ahead RA requirements and address potential cost-shifting, customers enrolled as a result of the 4,000 gWh expansion will not begin service until January 2020.
    c. Eligibility to enroll new DA customers is based off the waitlist that went into effect on January 1, 2019.
2. Whether there are any timing or process issues related to the increase in DA load and the Commission's rules and regulations for RA, the Integrated Resource Plan (IRP), and the Power Charge Indifference Adjustment (PCIA).
3. Whether the Commission must take any additional action to comply with Section 365.1 (e)(2) of SB 237's mandate

[4] The large IOUs are PG&E, SCE, and SDG&E.

that "[a]ll residential or non-residential customer accounts that are on [D]irect [A]ccess as of January 1, 2019, remain authorized to participate in direct transactions."

4. Any other substantive issues necessary to implement Section 365.1.

3. Substantive Matters

3.1. Apportionment Methodology

SB 237 directs the Commission to increase the maximum allowable kilowatt-hour annual limit for DA transactions by 4,000 gWh and apportion the increase among the service territories of the IOUs. In order to allow equal access to the DA program, the Commission is apportioning the 4,000 gWh to each IOU's service territory based on the proportion of each respective IOU's eligible DA load to the total statewide eligible DA load.

Commission Staff calculated the total eligible statewide DA load using the latest 12-month average load data from March 2019, which was provided by the IOUs.[5] Specifically, the eligible DA load for each IOU's service territory was calculated by adding total bundled and unbundled customers load, less the current DA load,[6] the reserved DA load,[7] and total residential customers,[8] plus legacy residential DA customers.[9] Next, the total eligible DA load was added to each IOU's service territory. Then, based on the proportion of each respective

5 *See* PG&E April 11, 2019 Data Response; SDG&E April 11, 2019 Data Response; SCE April 11, 2019 Data Response. These data responses were filed in R.19-03-009 on April 11, 2019.

6 Current DA load is the average DA load for all customer classes.

7 Reserved DA load is the current load that is pending an offer or DA affidavit or is in safe harbor status or a set-aside pursuant to Decision (D.) 10-03-022.

8 The total residential load is the total average residential load, including bundled and unbundled customers (*e.g.*, legacy DA residential customers and CCA residential customers).

9 Legacy DA is defined as grandfathered residential DA customers.

IOU's eligible DA load to the statewide total DA load, the Commission determined each IOU's percentage share of the 4,000 gWh increase. Finally, Commission Staff combined each IOU's share of the 4,000 gWh increase with its existing DA allowance cap.

Several parties support Commission Staff's proposal,[10] and no party opposes it. We find that Commission Staff's methodology is just and reasonable. Accordingly, the new DA cap for each respective IOU is stated in the column titled "Final Authorized Cap" in Table 1 below.

Table 1-Authorized DA Cap Increase by Service Territory (in kWh)

	Total Eligible Load[11]	% of Total Load	Apportionment of 4,000 gWh	Prior Cap[12]	Final Authorized Cap
Statewide	89,348,222,605	100	N/A	N/A	N/A
PG&E	41,842,337,444	46.83	1,873,225,285	9,520,000,000	11,393,225,285
SCE	39,019,860,000	43.67	1,746,866,759	11,710,000,000	13,456,866,759
SDG&E	8,486,025,161	9.50	379,907,956	3,562,000,000	3,941,907,956

3.2. January 2020 Enrollment

3.2.1. Commission Staff's Proposal

In R.19-03-009, Commission Staff proposes to allow service for the new DA expansion to begin starting on January 1, 2020. We recognize that SB 237 directs the Commission to issue an order that increases the annual limit of the DA cap by June 1, 2019, and we also find that we must consider the impact that adding

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10 AReM Comments at 3; AEE/AEBG Comments at 7; CLECA Comments at 2; DACC Comments at 2; PG&E Comments at 2; SDG&E Comments at 2; UC Comments at 3.

11 *See* PG&E April 11, 2019 Data Response; SDG&E April 11, 2019 Data Response; SCE April 11, 2019 Data Response.

12 *See* D.10-03-022, Appendix 1.

4,000 gWh to the DA program will have on existing state laws and regulations, in particular the Commission's requirements for the RA program, IRP and Long-Term Procurement program, and PCIA.

To ensure the reliability of electric service in California, Pub. Util. Code § 380 and the Commission's RA program requires that LSEs procure the requisite capacity for the California Independent System Operator requires to operate the electricity grid. The RA program has several monthly and annual filing requirements. Relevant here, LSEs must submit to the Commission annual year-ahead filings that demonstrate that: (1) 100 percent of Local RA requirements for each month in the next two compliance years and 50 percent of Local RA requirements for the third compliance year have been met, (2) 90 percent of System RA obligations for the five summer months in the next compliance year have been met, and (3) 90 percent of flexible RA requirements for each month of the coming compliance year have been met. Because RA planning is performed on a year-ahead basis, LSEs were required to file the preliminary 2020 year-ahead load forecast on April 19, 2019, with forecast adjustments due on August 16, 2019.[13] LSEs are also permitted to true-up the forecast during the compliance year; however, the adjustments only apply for the months of July through December. With respect to the Commission's IRP and Long-Term Procurement requirements, LSEs are required to file the next biennial IRP on May 1, 2020.[14]

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[13] D.05-10-042 (finding that preliminary load forecasts must be submitted by mid-April of each year); D.11-06-022 (finding that optional revisions to the preliminary load forecast shall be submitted by mid-August); *see generally* D.17-06-027 (clarifying that the purpose of the Mid-August adjustments is to refine the accuracy of the preliminary forecast).

[14] *See* D.18-02-018 at 170.

3.2.2. Comments

SCE argues that, because the RA program requires that the load forecasts for 2020 must determine the amount of load for 2021 and 2022 Local RA requirements, LSEs should be given ample time to perform accurate RA forecasting.[15] SDG&E argues that the Commission's role in regulating the resource planning process is particularly important given that the majority of the state's energy procurement will be conducted by Community Choice Aggregators (CCAs) within the next decade; thus, requiring that all LSEs fulfill their planning requirements is critical.[16]

PG&E, CalCCA, and EBCE argue that, for the expansion, the Commission should adopt the migration rules that are similar to the rules established in Resolution E-4907, Registration Requirements for Community Choice Aggregators. PG&E argues that, consistent with the migration rules established in Resolution E-4907 ESPs seeking to serve new load pursuant to the DA expansion should submit a "waiver" and be required to procure RA capacity from the original LSE or be subject to a future Commission determination in a RA proceeding on cost responsibility.[17] Also, PG&E argues that because the RA program requires LSEs to file 2020 year-ahead load forecasts on April 19, 2019, Energy Service Providers (ESPs) serving the new load as a result of the DA expansion will not be able to "participate in *all* aspects of the year-ahead RA process . . . ;" therefore, initiating service in January 2020 will cause over-procurement of energy and cost shifting, among other issues.[18] Similarly, EBCE

[15] SCE Comments at 5.

[16] SDG&E Comments at 3-4.

[17] *Id.* at 4.

[18] PG&E Comments at 3-4 (emphasis added).

argues that because it could lose over three percent of its load, it could be required to carry resource adequacy for departing customers.[19]

In response, Shell Energy argues that the waiver requirement under Resolution E-4907 should not apply to ESPs as ESPs will be able to adjust their load forecasts and related capacity procurement obligation, consistent the with the Commission's RA program procedures.[20] In response, PG&E reiterates that, for the DA new load, ESPs will not be able to participate "in the full year-ahead process" for the RA program.[21]

CalCCA and EBCE both assert that CCAs are required to provide one-year's notice of departing load, while Commission Staff's proposal would allow the DA expansion to occur after only six months' notice.[22] CalCCA argues that adopting a multi-year phase-in approach for the DA expansion that is similar to the approach adopted in Resolution E-4907 is necessary so that CCAs are given the opportunity to mitigate the impacts from having stranded costs associated with load that could depart CCA service to join the DA Program.[23]

DACC, Energy Users Forum, and Shell Energy also disagree with PG&E and CalCCA's contention that the migration-related rules that are similar to the rules established in Resolution E-4907 should apply to the DA expansion.[24] DACC and Shell Energy both argue that Resolution E-4907 was established to

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[19] EBCE Comments at 4.

[20] Shell Energy Reply Comments at 4-5.

[21] PG&E Reply Comments at 2-3.

[22] CalCCA Comments at 8-9.

[23] *Id.* at 14.

[24] DACC Reply Comments at 6-8; Energy Users Forum Reply at 2-3; Shell Energy Reply Comments at 4.

ensure that newly-operational CCAs adhere to the Commission's RA Requirements, an issue that is not relevant in this proceeding as the ESPs have procedures in place to update their respective load forecasts.[25]

Further, DACC argues that "delaying the departure of new DA load until 2021 would clearly be contrary to the Legislature's intent with respect to the 4,000 gWh expansion."[26] Energy Users Forum argues that additional notice for DA expansion is unnecessary as the load cap on the DA program sufficiently distinguishes that program from CCA services, which could cause unlimited amounts of load to depart bundled service.[27]

With respect to the IRP program, PG&E states that "[s]o long [as] DA customers do not begin service until January 2020, there would be ample time for DA providers to incorporate new DA customers in their 2020 IRPs."[28] However, PG&E argues, if the pending IRP proceeding results in additional procurement mandates, the Commission should ensure that the new mandates consider the impact that the DA expansion will have on each LSE's load profile.[29] Shell Energy argues that, because the IRP biennial reporting process does not have a plan due until next May 1, 2020, the ESPs will have adequate time to plan for RPS, energy storage, and RA procurement.[30]

PG&E also argues that a DA expansion in January 2020 could impact its Energy Resource Recovery Account (ERRA) forecasting proceeding and 2020

[25] DACC Comments at 8; Shell Energy Reply Comments at 4.

[26] DACC Reply Comments at 8.

[27] Energy Users Form Reply Comments at 3.

[28] PG&E Comments at 6.

[29] *Id.* at 6.

[30] Shell Energy Comments at 6.

PCIA revenue requirement and rate calculation. PG&E argues that its ERRA report includes the PCIA revenue requirement and is filed in June 2019, with adjustments required by November 2019.[31] In response, Shell Energy argues that, because the identity of the ESP for each incremental DA customer enrolled under the DA expansion will be known by November 2019, PG&E's concern about the impact that the DA expansion will have on the PCIA an ERRA proceedings is unjustified.[32]

3.2.3. Discussion

We are persuaded by the comments on the proposed decision that argue against allowing customers who enroll in the DA expansion to begin service on January 1, 2020, since a 2020 start would only be possible if some LSEs did not have to comply with all of the Commission's RA forecast requirements. In D.18-06-030, the Commission emphasized the importance of accurately forecasting year-ahead load by stating that "[p]articipation in the year-ahead [RA] forecasting process by *all LSEs* who plan to serve load in the following year, including *accurate forecasting of expanded territory or customer base*, will ensure a more equitable allocation of the RA requirements."[33] With the DA expansion, the customer base of some LSEs will expand as some LSEs who are ESPs that provide DA service will gain load while some LSEs that provide either bundled or CCA service will lose customer load.

As noted earlier, on April 19, 2019, LSEs were required to submit preliminary 2020 year-ahead load forecasts. Because the Commission's

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[31] PG&E Comments at 6.

[32] Shell Energy Reply Comments at 6-7.

[33] D.18-06-030 at 18; *see also id.* at Conclusion of Law 7 (emphasis added).

allocation of RA requirements is based on the forecasts in the preliminary filings, we find that it is reasonable that some LSEs would have procured the necessary generation resources at that time based on that forecast. If the customers of such LSEs are permitted to join the DA expansion in 2020, those affected LSEs will have over-procured generation resources. For example, EBCE states that it expects to lose approximately three percent of its load if the DA expansion is implemented starting in 2020 and, therefore, it is likely that EBCE will be required to "carry resource adequacy for departing customers."[34] CalCCA asserts that the procurement costs for departing customers that start service under the DA expansion in January 2020 would be unduly shifted to the remaining customers of CCAs and IOUs.[35]

Thus, even if the ESPs with DA expansion customers are able to demonstrate in their October RA filing that they can procure the requisite generation resources, procurement problems could persist if the DA expansion were to begin in 2020. Affected bundled or CCA LSEs might not able to divest the RA requirement that was procured but is no longer needed. Therefore, allowing customers who enroll in the DA expansion to start DA service in 2020 could frustrate the RA program goal of ensuring that RA requirements are allocated equitably.

Accordingly, we find that implementing the DA expansion does not justify an exception the Commission's prior determination that "[a]ll load serving entities shall participate in all aspects of the year-ahead RA process for load they

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[34] EBCE Comments at 4; EBCE Comments to the Proposed Decision at 2, 4.

[35] CalCCA Comments to the Proposed Decision at 2-4.

plan to serve in the following year."[36] While we adopt the Commission Staff's proposal to delay the enrollment date for the DA expansion, we find that because the RA year-ahead forecasts are due in April of the prior year, the earliest date that customers may enroll in the DA expansion is January 1, 2021, instead of January 1, 2020.

Lastly, given the revised enrollment timeline, as stated in section 3.3, we find that CalCCA's contention that the ESPs should be required to comply with the one-year migration rule is moot. Affected CCAs will be given the first notification of departing load on September 10, 2019, giving CCAs over 12 months of notice for departing load. Specifically, the IOUs will provide CCAs with aggregated hourly peak demand megawatt (MW)[37] and hourly load megawatt hours (MWh)[38] data for the latest entire year to date. Also, on February 10, 2020, which is after the Direct Access Service Request (DASR) forms have been submitted and historic load year of 2019 has ended, the IOUs will provide affected CCAs with an update of the hourly peak demand and hourly load.

3.3. Customer Eligibility

In R.19-03-009, Commission Staff proposed to allow the new load to be assigned to customers based on the DA waitlist that is effective as of January 1, 2019 (2019 Waitlist). The waitlist process is a part of the existing DA

[36] D.18-06-030 at Ordering Paragraph 5.

[37] Hourly peak demand is the average instantaneous peak demand across four consecutive 15 minute periods within each hourly interval

[38] Hourly load is the sum of energy across the four consecutive 15 minute periods within an hourly interval.

Enrollment Procedures, established in D.10-03-022, as modified in D.12-12-036, which direct the IOUs to enroll new load into the DA program when space under the DA allowance cap becomes available, either from departing load or a statutory mandate, as is the case here.

To join the waitlist, a customer must provide IOUs with a six months' notice that it would like to join the DA program. The notice, which is provided in the form of a Notice of Intent (NOI),[39] is submitted during the Open Enrollment Window, which runs annually during the second full week of June. After the IOUs review the NOI for completeness and other issues, a process that takes 30 days, the IOUs run a program that randomly assigns numbers to the NOIs, and after ten days, the IOU will inform the customers of their position on the waitlist. A customer who has a waitlist position that can be accommodated by the DA program cap, has 15 business days to indicate whether it chooses to join the DA program. If the customer elects to join the DA program, it must select an ESP and submit a DASR form within 45 days of the customers' earliest service date, as indicated by the IOUs.

In sum, each cycle of the existing DA enrollment process begins in mid-June and is effective (meaning, first meter reads under the new electricity provider) starting no earlier than January of the following year, if no load is available under the cap when the list is created, which has been the case for several years. SB 237 directs the Commission to authorize the cap increase and apportion it to each respective service territory by June 1, 2019. Accordingly, the customers who are on the 2019 Waitlist have already undergone the vetting and

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[39] The NOI includes the customer name, submitter name, number of service accounts being submitted. *See* D.12-12-026, Appendix 1 (Random Number List Switching and Enrollment Process).

notification process that normally occurs as part of the existing DA enrollment procedures.

3.3.1. Comments

Several parties oppose Commission Staff's proposal.[40] AEE/AEBG, EPUC, PG&E, SDG&E, and Shell Energy argue that, because the 2019 Waitlist was generated in June 2018, which is before SB 237 was enacted, Commission Staff's proposal does not give all eligible customers an opportunity to compete for the increase.[41] CLECA argues that, because SB 237 is a significant regulatory change and similar proposals have failed in the past, a new waitlist should be generated.[42] Commercial Energy argues that relevant regulatory and market-related changes, such as the CCA growth,[43] PG&E's bankruptcy filing, and the enactment of SB 237, all have occurred since the 2019 Waitlist was generated; thus, to account for customers that would be motivated by those changes to move to the DA program, a more recent waitlist should be used to allocate the cap increase.[44]

Several parties recommend that the Commission implement a multi-year approach to address this issue. SCE proposes that the Commission use the 2019 Waitlist to implement a portion of the increase in 2020 (lottery was conducted in mid-June 2018) and the waitlist that is generated for 2020 to enroll

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[40] Commercial Energy Comments at 2-4; CLECA Comments at 3; DACC Comments at 3-4. EPUC Comments at 5; SDG&E Comments at 3; Shell Energy Comments at 3-4.

[41] AAE/AEBG Comments at 6-7; EPUC Comments at 5-6; PG&E Comments at 4-5; Shell Energy Comments at 5.

[42] CLECA Comments at 2-3.

[43] CCAs were established in the cities of Los Angeles and San Diego. Commercial Energy Comments at 3.

[44] Commercial Energy Comments at 3-4.

the remaining portion of the increase in 2021 (2020 Waitlist).[45] PG&E asserts that "[f]rom a customer perspective, it may make sense to parse the new allocation into multi-year phases."[46] AEE/AEBG argue that the Commission should allow at least some of the increase to be served by a new lottery. AEE/AEBG assert that spitting the increase between the 2019 Waitlist and 2020 Waitlist would balance the interests of customers who have participated despite the low chances of success with customers who have a strong interest in the program but have elected not to participate in past lotteries for DA because the DA queue has been oversubscribed for many years.[47]

Energy Users Forum argues that it is fair for the Commission to use the 2019 Waitlist. Energy Users Forum argues that the customers on the 2019 Waitlist primarily signed-up because they anticipated that new legislation would expand the DA cap as was the case with SB 695. Thus, Energy Users Forum argues, denying customers who have spent resources following the existing waitlist process would unjustly deprive the 2019 Waitlist customers of their position in the queue.[48]

DACC argues that, because Commission Staff proposes to begin enrollment in 2020, customers should be enrolled in the DA expansion pursuant to the waitlist that is granted from the 2019 lottery, as that waitlist will be effective starting January 1, 2020 (2020 Waitlist).[49] If the Commission uses the 2020 Waitlist, DACC proposes the following enrollment schedule, which requires

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45 SCE Reply Comments at 2.

46 PG&E Comments at 4.

47 AAE/AEBG Comments at 6.

48 Energy Users Forum Reply Comments at 5.

49 DACC Comments at 3.

modifications to some but not all of the existing DA enrollment schedule deadlines: (1) NOIs will continue to be submitted during the second week of June 2019 (June 10-June 14), (2) IOUs will continue to vet the NOIs over 30 business days, ending on July 26, 2019, (3) IOUs will continue to notify customers of their position in the queue within ten days of reviewing the NOIs or by August 9, 2019, (4) notified customers will state whether they elect to join the DA program within 15 days, (5) notified customers who decide to enroll in the DA program shall select an EPS, and (6) the ESPs will submit the DASR forms by December 2019.[50] AReM also offers an expedited schedule that provides that the ESPs would submit the DASR form by August 13, 2019.[51]

DACC argues that, even though affected LSEs would not be able to reflect the load shifts caused by the DA expansion in their respective 2020 RA year-ahead August update filing, using the 2020 Waitlist can nevertheless be accommodated by existing RA program rules. DACC asserts that the 4,000 gWh increase is less than two percent of the total August 2019 peak load for the IOUs. Thus, DACC argues, the increase can be accommodated by the existing RA rules because 10 percent of the RA System requirements are not required to be procured in the year ahead, and although 100 percent of the RA Local requirements must be procured in the year ahead, the current rules permits RA Local requirement true-ups in the middle of the compliance year.[52]

PG&E argues that using the 2020 Waitlist process to enroll the load under the DA expansion is infeasible as ESPs will not know whether they will have

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50 *Id.* at 4-5.

51 AReM Reply Comments at 12-13.

52 DACC Comments at 6.

load gains or losses by August 16, 2019, the deadline to make adjustments to the 2020 RA year-ahead load forecast.[53] PG&E disagrees with DACC's contention that the RA true-up that is allowed during the compliance year is appropriate to account for load shifts that will occur on January 1, 2020, as the true-up only applies for the latter half of the year from June to December 2020; thus, inequities in RA obligations could occur for six months.[54]

SCE and PG&E argue that the affected LSEs would not have enough time to comply with the 2020 RA requirements if the Commission uses the 2020 Waitlist.[55] SDG&E disagrees and argues that it would be able to use the2020 Waitlist to enroll load for the DA expansion.[56]

Energy Users Forum argues that the Commission should use the waitlist that makes sense. Energy Users Forum asserts that, if the Commission determines that the expansion must be accounted for in each LSE's August RA year-ahead forecast update, then using the 2019 Lottery results is impractical as suppliers and customers would not have sufficient time to make procurement decisions. Energy Users Form explains that the procurement process and selecting an ESP typically takes months; thus, if the 2020 Waitlist is used, the procurement process would be delayed by at least six weeks.[57]

UC supports the Commission Staff proposal. UC argues that all of the steps necessary for customers to enroll in the DA expansion by January 1, 2020—including customer notification, acceptance, and procurement contracting—will

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[53] PG&E Reply Comments at 2-3.

[54] *Id.* at 3.

[55] PG&E Reply Comments at 2-3; SCE Reply Comments at 1-2.

[56] SDG&E Reply Comments at 2.

[57] Energy Users Forum Comments at 5.

occur in 2019; accordingly, the 2019 Waitlist should be used.[58] UC argues that the 2019 Waitlist does not expire until December 31, 2019, and correctly determines the order in which DA status should be offered under the expanded cap.[59]

AReM does not support or oppose the proposal but notes that the 2019 Waitlist is "vetted and available, and would allow the IOUs to start the process of notifying eligible customers immediately."[60] However, AReM argues that if the Commission elects to use the 2020 Waitlist, the Commission must ensure that the DA customers select an ESP by mid-August, the deadline for ESPs to submit their final revised load forecasts for purposes of establishing RA obligations for 2020 compliance.

3.3.2. Discussion

As the comments demonstrate, there are valid arguments for using the 2019 Waitlist and for using the 2020 Waitlist. We agree with the parties who recommend that the Commission should balance the interests of customers who participated in the 2018 lottery and those who have a strong interest in participating now that the DA cap has been increased. Moreover, we find that it would be inconsistent with the goal of expanding customer choice to deny parties who are interested in direct access service, but who did not participate in the 2018 enrollment process, the opportunity to be selected under the new cap.

Accordingly, we find that the increase in the DA cap should be apportioned between the 2019 and 2020 waitlists. Half of the DA expansion

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[58] UC Comments at 3.

[59] *Id.* at 3.

[60] AReM Comments at 4.

(specifically, 2,000 gWh) must be enrolled using the 2019 Waitlist and the remaining half of the DA expansion (specifically, 2,000 gWh) should be enrolled using the 2020 Waitlist.

The Commission's approach is based on two considerations: 1) allowing customers on the 2019 Waitlist the opportunity to participate in the DA market; and 2) allowing customers who did not participate in the 2018 direct access enrollment process the opportunity to be selected for service under the increased cap. By utilizing this approach, the Commission: 1) provides those that entered the lottery for the 2019 waitlist an opportunity to participate in an expanded DA market as they intended when enrolling in the DA lottery for 2020 with the expectation that increased DA capacity may become available; and 2) fosters customer choice.

With respect to using an expedited 2019 enrollment schedule, such as that proposed by DACC, customers would not select an ESP until December 2019, well after even the 2020 RA year-ahead adjusted forecast is due on August 16, 2019. And, we disagree with DACC's contention that the affected LSEs can update their forecast during the compliance year as that process only applies to half of the year and would, therefore, present cost shifting issues for affected LSEs. While we appreciate that AReM also offered for consideration an expedited enrollment schedule for generating the 2020 Waitlist, we find that it is impractical for the IOUs to implement, for customers to adequately participate, and for LSEs to adhere to RA program requirements, as ESPs would only have two days to get notice of customer departures and revise their RA plans accordingly. Moreover, as discussed earlier, customers cannot take service under the DA expansion until 2021, at the earliest.

Accordingly, the table below summarizes the critical deadlines and milestones for each phase of the DA expansion. If some of the DA expansion is not enrolled pursuant to the deadlines stated below, then the next available service date for the remaining DA expansion load will be the following year (*i.e.*, 2022) so that affected LSEs can account for the DA expansion in their RA year-ahead filings.

Except for the revised deadlines below, the IOUs will use the existing DA lottery process to generate the 2020 Waitlist. Consistent with that process, any DA load that becomes available due to customers who were awarded DA from the 2019 Waitlist and who choose not to pursue DA will be awarded to other customers on the waitlist. If the customer notifies the IOU prior to December 31, 2019 at 11:59 p.m., then the IOU should use the 2019 Waitlist to reallocate the available load. If the customer notifies the IOU after the December 31, 2019 deadline, then IOUs should use the 2020 Waitlist to reallocate the available load. Pursuant to D.18-06-030, regardless of which waitlist a customer is selected from, an LSE may not serve customers whose load was not represented in that LSE's year-ahead RA forecast due in April.

For space that becomes available under the pre-SB 237 DA Allocation cap,[61] the IOUs will continue to enroll load pursuant to the existing DA lottery process.

Table 2 –Schedule for DA Expansion

Date	Description of Deadline
14-Jun-19	deadline for customers to submit NOI to participate in 2020 waitlist
29-Jul-19	deadline for review, audit, and confirmation of NOI for

[61] *See supra* Table 1, Prior Cap Column.

	the 2020 waitlist
12-Aug-19	deadline for IOUs to finish notifying customers on the 2019 and 2020 Waitlist of their eligibility to participate on January 1, 2021
3-Sept-19	deadline for customers to notify IOUs that they will pursue DA
10-Sept-19	deadline for IOUs to notify CCAs of departing load
31-Dec-19	2019 Waitlist expires
3-Feb-20	latest deadline for customers and ESPs to negotiate contracts and submit DASR to IOUs
10-Feb-20	deadline for IOUs to notify CCAs of departing load
Mid-Apr-20	deadline to make RA forecast filing for 2021
1-Jan-21	first possible meter read for customers on DA service

3.4. Other Issues

3.4.1. PCIA Vintage

Pursuant to Pub. Util. Code § 366.2(a)(4), which directs the Commission to ensure that CCA implementation "shall not result in shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation," the Commission established the PCIA.[62] To differentiate between customers that leave bundled service at different times, the Commission established a "vintage" process that groups "departing customers based on the date they leave utility bundled service so that they are responsible for generation costs incurred on their behalf before their departure to a CCA."[63] However, the Commission also held that since vintages are assigned

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[62] Decision Resolving Vintaging Methodology for Power Charge Indifference Adjustment for Community Choice Aggregation Customers, D.16-09-044 at 3 (PCIA Decision), *modified by*, D.17-08-028. The PCIA is assessed by an IOU on departing load customers to cover generation costs incurred on that customer's behalf before the customer decided to leave bundled service.

[63] *Id.* To differentiate between customers that leave bundled service at different times, the Commission determined that the customer's "vintage" should be determined based on the year in which they depart bundled service. (*Id.* at 12.)

based on initial service in a territory, the PCIA vintage should be tied to the service territory; thus, if a CCA customer with one vintage moves to a CCA territory with a different vintage, that customer would adopt the vintage of their new location.[64]

AReM, CLECA, and Shell Energy request that the Commission specify the PCIA vintage that will be applicable to customers who leave CCA service to join the DA program.[65] AReM asserts that the PCIA vintage that is assigned to CCA customers should not change if that customer leaves CCA service to join the DA program. Similarly, DACC asserts, and CalCCA agrees,[66] that because a CCA customer will have already departed utility bundled service, no utility procurement should have occurred to justify imposing a revised PCIA vintage.[67] And CLECA argues that the PCIA "vintages do not change regardless of customer movement among non-utility load serving entities, be they ESPs or CCAs."[68]

PG&E disagrees that clarification on this issue is necessary because its tariff provides that "a customer migrating directly from CCA to DA service, or vice-versa, would retain [its] vintage year assignment."[69]

We find that AReM's assertion is consistent with Commission precedent. As discussed above, D.16-09-004 provides that the vintage assigned to a

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64 *Id.* at 15.

65 AReM Comments at 6-7; CLECA Reply Comments at 4; Shell Energy Reply Comments at 3.

66 CalCCA Reply Comments at 10.

67 DACC Comments at 8.

68 CLECA Reply Comments at 4.

69 PG&E Reply Comments at 8 (citing PG&E Electric Schedule DA-CRS, DA Cost Responsibility Surcharge, effective June 1, 2010, Special Condition 8).

customer who leaves an IOU's bundled service to join a CCA will not change when that customer leaves that same CCA's territory to join the DA program, as CCAs are not electrical corporations that provide bundled service.

3.4.2. Small IOU Respondents

Bear Valley, Liberty, and PacifiCorp (together, California Association of Small and Multi-Jurisdictional Utilities or CASMU), argue that they should be removed as respondents to this proceeding. The CASMU utilities contend that no ESP is registered to operate in their service territories, which primarily consist of rural and/or mountainous regions of the state where there are few commercial and industrial customers.[70]

Moreover, CASMU utilities contend, D.95-12-063, which established the DA program did not apply to the CASMU utilities' service territories, and D.10-03-022, which increased the DA cap pursuant to SB 695, also only applied to the large IOUs.[71] CASMU Utilities argues that SB 237 did not alter the existing statutory requirements as to how the DA program applies to their service territories.

We agree that SB 237 does not require the Commission to apportion the DA cap increase to the CASMU utilities. Accordingly, consistent with Commission precedent, we remove the CASMU utilities as respondents to this proceeding.

3.4.3. Waitlist Disclosure

CalCCA argues that the Commission should order the IOUs to disclose "the complete" DA waitlist to CCAs so that CCAs can model and plan for

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[70] CASMU Comments at 2.

[71] *Id*. at 4.

customer load that may depart CCA service to join the DA program.[72] Specifically, CalCCA argues that, in addition to load data, CCAs also require customer-specific data to "adequately plan for procurement or rate-setting due to the variety of sizes and types of potential DA customers, or their priority on the DA waitlist."[73]

SDG&E argues that, pursuant to D.06-06-066, as modified by D.07-05-032 and D.06-12-030, SDG&E is prohibited from providing customer specific information to third parties, unless the respective customer consents.[74] PG&E argues that data on the waitlist, such as customer name, service agreement number, and lottery placement, is confidential and should not be disclosed without the customer's consent. CLECA and DACC both contend that, to protect customer confidentiality, the Commission should not require the IOUs to disclose the complete waitlist with customer-specific information.[75]

AReM asserts that providing CCAs with the identity and queue position of customers who are on the waitlist is unnecessary to assess the potential impact of departing load. AEE/AEBG, PG&E, and SCE each assert that, while aggregated waitlist information could help with the CCAs' procurement planning process, the "complete waitlist," which includes customer-specific data is not relevant for that purpose.[76] SCE asserts, and Energy Users Forum and CLECA agree,[77] that

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[72] CalCCA Comments at 9.

[73] *Id.* at 5.

[74] SDG&E Reply Comments at 4.

[75] CLECA Reply Comments at 3-4; DACC Reply Comments at 8.

[76] AEE/AEBG Reply Comments at 5; PG&E Reply Comments at 7; SCE Reply Comment at 5.

[77] CLECA Reply Comments at 4 (citing D.14-05-016 at 140-141, Findings of Fact 19 and 20); Energy User Forum Reply Comments at 3.

CCAs should be provided with aggregated load data that complies with the "15/15" rule, as this level of data is appropriate for planning purposes.[78]

DACC also argues that disclosing the complete waitlist would allow CCAs to market to prospective DA customers and, therefore, give CCAs an unfair advantage over ESPs.[79] AEE/AEBG assert that customers who enter the waitlist should have confidence that their information will not be used for any purpose other than allocating DA load.[80]

AReM and Shell Energy support adding to the DA enrollment process a step that requires IOUs to provide notice to the CCAs when a CCA customer has elected to join the DA program.[81] AReM argues that notifying CCAs of departing load is necessary to allow the affected CCA to adjust its forecasts and procurement resources accordingly.[82]

3.4.4. Discussion

We find that CalCCA has demonstrated that, for procurement planning purposes, it is reasonable for CCAs to have advance notice of customer load that may depart CCA service as part of the DA expansion. Pursuant to Pub. Util. Code § 380(e), LSEs, including CCAs, are required to adhere to the Commission's RA requirements. Given that the migrations that could occur pursuant to the cap increase are larger than the typical DA migrations, we find that CCAs should be provided with aggregate load data to facilitate RA planning activities.

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[78] SCE Reply Comments at 5.

[79] DACC Reply Comments at 8.

[80] AEE/AEBG Reply Comments at 5.

[81] AReM Comments at 5; Shell Energy Reply Comments at 2.

[82] AReM Comments at 5.

During the workshops, the IOUs indicated that they have provided CCAs with aggregated load data of customers on the DA waitlist on a case-by-case basis; thus, we find that continuing to provide this information will not be unduly burdensome for the IOUs. Thus, as discussed in sections 3.2.3 and 3.3.2 of the instant decision, after the IOUs determine which customers have chosen to join the DA program, the IOUs must provide the CCAs with the amount of aggregated load of customers who have elected to depart a CCA's service territory to join the DA program. CCAs will receive aggregated hourly peak demand (MW) and the hourly total load (MWh) data for 2019, to plan for RA requirements and shifts in load. This timeline will provide CCAs with load migration data months before mid-April 2020, the deadline for LSEs to file their preliminary 2021 RA year-ahead forecast.

3.4.5. Phase 2 – Recommendation to Legislature on Increasing Direct Access

As noted in the Scoping Memo, the Assigned Commissioner will set forth the procedural schedule and issues for Phase 2 in a subsequent scoping memo that will be issued during or before the third quarter of 2019.

In addition, the Scoping Memo noted that some issues are outside the scope of this proceeding or will be addressed in Phase 2. One issue that will be addressed in Phase 2 is CalCCA's contention that former DA customers who switch to CCA service should be able to later switch back to DA service without having to use the existing waitlist/enrollment process.[83] CalCCA argues that because DA customers may switch between ESPs, limiting a CCA customer's ability to go back to its waitlist position for the DA program "creates an artificial

[83] CalCCA Comments at 11.

barrier for unbundled customers and is contrary to the Commission's stated DA policies."[84]

SCE argues that CalCCA's proposal "ignores the practical matter of the cap on DA load, and the need to release unused Direct Access load to other customers when space under the cap becomes available."[85] DACC argues that customers who switch from the DA program to CCA service should not be permitted to reserve their share of allowable DA load for some indefinite period. DACC argues that reserving DA load would be unfair to prospective DA customers and to the ESPs that would otherwise serve the available DA load.[86] Similarly, PG&E argues that reserving load beyond the allowable safe harbor period would mean that DA load would not be available to other customers; otherwise, allowing the load to be available to other customers and to a CCA customer that decides to return to DA service would cause the respective IOU to exceed its allowable DA load cap.[87] The Energy Users Forum states that, if and when DA is "fully open," it would support CalCCA's proposal.[88]

We find that CalCCA's argument is misplaced as it correlates switching within a single retail service program with switching between two different retail services programs. Unlike CCA service, pursuant to Assembly Bill 1X,[89] the DA program was suspended in 2001, with grandfathered load and new DA enrollments permitted up to the load cap established based on pre-suspension

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[84] *Id.* at 11-13.

[85] SCE Reply Comments at 4.

[86] DACC Reply Comments at 9.

[87] PG&E Reply Comments at 5.

[88] Energy Users Forum Reply Comments at 3.

[89] Stats. 2001, 1st Extraordinary Session.

load levels,[90] and subsequently statutorily mandated increases, such as SB 237. Thus, when a DA customer switches ESPs, the activity does not impact the DA cap as that customer's DA load is already being served by available DA allowances.

Accordingly, we find that allowing customers to switch from CCA service to the DA program is not comparable with DA customers switching between ESPs. Further, we find that reserving DA load for customers who switch from DA service to any other retail service is unreasonable. Available load under the DA cap is in high demand, as demonstrated by the waitlist; therefore, such load must be allocated in an equitable manner to those customers who are interested. Customers who leave the DA program to return to bundled service must also use the waitlist enrollment process to rejoin the DA program, and we find that CalCCA has not demonstrated that former DA customers who switch to CCA service should be entitled to an exemption.

However, if and when the cap on DA service is lifted, this issue and the waitlist process should be revisited and, therefore, this issue may be considered during Phase 2 of this proceeding.

3.4.6. Other Procedural Issues

CalCCA argues that some CCA service territories that have six to 12 percent of load on the DA waitlist could "face disparate impacts" as those amounts "represent a significant volumetric shift for already projected-and procured for—load along with potential changes in overall load profile which would impact procurement planning."[91] Further, CalCCA asserts, that unlike

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[90] *See* D.01-09-060 at 8, as modified by D.01-10-036; *see also* D.02-03-055, as modified by D.03-01-078, rehearing denied by D.03-09-027.

[91] CalCCA Comments at 6-7.

IOUs, CCAs are not guaranteed cost recovery through mechanisms such as the PCIA and the Cost Allocation Mechanism. To resolve this issue, CalCCA requests that the Commission establish a cap on the amount of customer load that is eligible to join the DA program (CCA Cap) and that the cap should be based on the "lesser of load currently on the existing waitlist or [the CCA's] fair share of load."[92]

PG&E asserts that "if the DA Load in the geographic area served by a CCA was capped, it would, in effect, create a second geographically-based cap on DA load," and that such a proposal is unfair and contrary to Commission precedent.[93] AReM, Commercial Energy, Energy Users Forum, and SCE, all argue that neither SB 237 nor any other state law directs the Commission to establish a separate DA customer participation cap to protect CCA service providers in the manner in which CalCCA proposes.[94] Commercial Energy argues that SB 237 concerns the allocation of additional DA capacity between the IOUs, not between CCAs.[95] AReM contents that, aside from SB 237, CCAs may experience a bulk departure at any time and should have an established risk management plan to address that outcome.

Moreover, AReM argues, the process for implementing the CCA Cap would discriminate against eligible non-residential customers that choose to get on the waitlist for the possibility of joining the DA program as such customers would be skipped over if they reside in an area where the CCA cap has been

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92 *Id.* at 7.

93 PG&E Reply Comments at 5.

94 AReM Reply Comments at 3; Energy Users Forum Reply Comments at 2; SCE Reply Comments at 3.

95 Commercial Energy Reply Comments at 3.

reached.[96] Similarly, AEE/AEGB argues that imposing the CCA Cap "could limit customer choice—an outcome that runs counter to the intention of SB 237."[97] Energy Users Forum argues that the CCA Cap would be an after-the-fact restriction on CCA customers that are skipped over as they did not have notice of such restriction at the time that they opted-in to CCA service.[98] DACC contends that using a CCA Cap to restrict eligible non-residential customers from joining the DA program is prohibited by Pub. Util. Code § 366.2(c)(14), which precludes CCAs from restricting the ability of retail customers from obtaining or receiving service from any authorized ESP.[99] PG&E argues that creating 12 different CCA Caps based on the waitlist and each respective CCA's "fair share" of the total load would be unduly burdensome for IOUs to maintain.[100] Further, AReM argues that imposing a CCA Cap would give CCAs special treatment over other retail service providers as neither an IOU nor an ESP may set a cap on the amount of customer load that may depart from their services.

We recognize stranded costs and cost-shifting are critical issues as, pursuant to statutory requirements,[101] the Commission has conducted several proceedings over the years to establish and revise the PCIA charge, which addresses cost shifts that could occur when bundled customers migrate to CCA services.

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96 AReM Reply Comments at 4.

97 AEE/AEBG Reply Comments at 7.

98 Energy Users Forum Reply Comments t 2.

99 DACC Reply Comments at 5.

100 PG&E Reply Comments at 6.

101 *See* Pub. Util. Code § 366.2 (2018).

We disagree, however, with the remedy that CalCCA proposes to address this concern. We find that implementing such a cap would be unduly discriminatory as eligible DA customers would be denied the ability to choose to join the DA program solely on the basis that a CCA in entitled to a "fair share" of that customer's load. Further, CalCCA's proposal would stifle customer choice and provide preferential treatment to certain LSEs (CCAs) over IOUs and ESPs, who have not had the benefit of such a cap. Moreover, we find that because the DA expansion will not be implemented until January 1, 2021, the affected CCAs will have an adequate amount of time to mitigate stranded costs and cost shifting associated with departing load. We also note that CCAs could consider revising their risk management plans or implementing mechanisms that are similar to the regulatory framework established for the PCIA to further mitigate cost shifting risks.

4. Comments on Proposed Decision

The proposed decision of Commissioner Picker in this matter was mailed to the parties in accordance with Pub. Util. Code § 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure.

On May 20, 2019, SDG&E, SCE, PG&E (together, Joint Utilities), AEE/AEBG, AReM, CalCCA, CLECA, Commercial Energy, DACC, EBCE, EPUC, SDWA, and Shell Energy filed comments. Reply comments were filed on May 28, 2019 by AReM, CalCCA, CLECA, DACC, PG&E and SCE. The proposed decision was revised throughout to clarify information as requested in the comments. In addition, section 3.2 was substantially revised to address comments concerning the Commission's RA program.

5. Assignment of Proceeding

President Michael Picker is the assigned Commissioner and Christine A. Powell is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The DA expansion is apportioned to the IOU territories based on each IOU's percentage share of eligible DA customers.

2. The total DA expansion represents approximately two to three percent of the forecasted August 2019 peak load for all the IOU service territories.

3. The 2019 Waitlist has already been generated.

4. The process for generating the 2020 Waitlist will begin in mid-June 2019.

5. For the 4,000 gWh DA expansion, 2,000 gWh should be applied to the 2019 Waitlist and 2,000 gWh should be applied to the 2020 Waitlist. Thus, the allocation to each IOU as stated in Table 1 shall be split equally between the 2019 and 2020 waitlists.

6. The new DA enrollments will cause affected LSEs to gain or lose customer load.

7. The next biennial IRP filing is due on May 1, 2020.

8. The last date for LSEs to submit their preliminary 2020 RA year-ahead adjusted forecast was April 19, 2019.

9. The IOUs are required to file adjustments to their PCIA revenue requirement filings by mid-November every year.

10. Concluding the enrollment process for the 2019 and 2020 Waitlist customers by February 3, 2020 will give LSEs enough lead time to update and submit their 2021 RA year-ahead adjusted forecast, including the filing that is due in April 2021.

11. The existing DA lottery process for enrolling DA load that becomes available when DA customers choose to exit DA service will allow for an orderly ongoing administration of the DA program.

12. A customer who has been allocated the right to take DA service using the 2019 Waitlist but who chooses not to take service has, for the purpose of administering the ongoing DA lottery process, chosen to exit that portion of their load from DA service.

13. Discontinuing use of the 2019 Waitlist after December 31, 2019 is consistent with the existing DA lottery process.

14. IOUs have previously provided CCAs with aggregate load data from the DA waitlist.

15. The DA waitlist contains confidential customer information.

16. The PCIA vintage is determined when a customer leaves bundled service, regardless of the type of LSE.

17. No ESPs operate in the service territories of the CASMU utilities.

18. CASMU utilities have historically been excluded from participating in the DA program.

Conclusions of Law

1. The Commission's apportionment methodology allocates the DA expansion in a manner that is just and reasonable.

2. The final authorized cap for each IOU service territory is just and reasonable.

3. Using the 2019 Waitlist and the 2020 Waitlist to enroll customers under the DA expansion is just and reasonable.

4. The revised enrollment schedule is reasonable as it is necessary to ensure that enrollment into the DA expansion does not conflict with the RA, IRP, and PCIA filing requirements.

5. It is reasonable to continue using the existing DA lottery process to allocate DA that becomes available when customers exit DA service.

6. Load that becomes available for DA service as a result of a customer on the 2019 or 2020 Waitlist choosing not to take DA service should be allocated using the existing DA lottery process, as modified by the timeline in Table 2.

7. If a customer who had the right to take DA service because they were on the 2019 Waitlist chooses not to take service prior to December 31, 2019, the available load should be reallocated using the 2019 Waitlist. Otherwise, the load should be reallocated using the 2020 Waitlist.

8. Unless otherwise legally authorized, IOUs are not permitted to release confidential customer data without first obtaining the customer's consent.

9. IOUs can provide customer data provided that the data is aggregated in a manner that is consistent with Commission precedent.

ORDER

IT IS ORDERED that:

1. The Direct Access (DA) cap for each respective Investor-Owned Utility is increased to the quantity stated in Table 1, column titled "Final Authorized Cap."

2. For the 4,000 gigawatt hour (gWh) increase, customers on the 2019 waitlist shall be permitted to enroll in 2,000 gWh, and customers on the 2020 waitlist shall be permitted to enroll in the remaining gWh.

3. The Direct Access (DA) enrollment schedule to enroll 2019 and 2020 waitlist in the DA expansion is as follows: (1) the deadline for customers to submit a Notice of Intent (NOI) to participate in the DA expansion is

June 14, 2019; (2) by July 29, 2019, each of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company (each an "IOU") must complete their review, audit and confirmation of the NOI for the 2020 waitlist; (3) by August 12, 2019, each IOU must notify the eligible 2019 and 2020 waitlist customers in that IOU's service territory that they may enroll in the DA program and direct these customers to submit their decisions regarding DA service to the IOU on or before September 3, 2019, at 5:00 p.m.; (4) if a notified customer declines the opportunity to join the DA program, the IOU must notify the next eligible customer in queue for that IOU's service territory, and direct these customers to submit their decision regarding DA service to the IOU on or before September 3, 2019, at 5:00 p.m.; (5) if a customer who is allocated the right to take DA service from the 2019 Waitlist declines the opportunity to take DA service at or prior to December 31, 2019, at 11:59 p.m., IOUs should use the 2019 Waitlist to reallocate that customer's load; (6) if a customer who is allocated the right to take DA service from the 2019 Waitlist declines the opportunity to take DA service after December 31, 2019, at 11:59 p.m., IOUs should use the 2020 Waitlist to reallocate that customer's load; and (7) notified customers who chose to switch to the DA program must select an Energy Service Provider (ESP) and have that ESP submit the Direct Access Service Request form to the respective IOU by February 3, 2020 at 5:00 p.m.

4. By September 10, 2019, the IOUs shall provide to each affected Community Choice Aggregator (CCA) the aggregate hourly peak demand and hourly load data for the latest entire year to date of 2019 and 2020 waitlist customers who chose to switch from that CCA's service to the Direct Access program.

5. By February 10, 2020, the Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall

provide to each affected Community Choice Aggregator (CCA) the aggregate hourly peak demand and hourly load data from January 1, 2019 to December 31, 2019 for 2019 and 2020 waitlist customers who have submitted Direct Access Service Request form.

6. By June 14, 2019, the Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall submit a Tier 2 Advice letter if they believe that tariff changes are necessary to comply with the provisions in this order. Proposed tariff changes should be included with the Advice Letter.

7. Bear Valley Electric Service, Liberty Utilities LLC, and PacifiCorp, d/b/a Pacific Power are removed as respondents to this proceeding.

8. Phase 1 of Rulemaking 19-03-009 is concluded. Rulemaking remains open to address the study for the Legislature in Phase 2.

This order is effective today.

Dated May 30, 2019, at San Francisco, California.

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