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 (Filed March 14, 2019)

POST-WORKSHOP COMMENTS OF
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

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I. Summary of CalCCA Position on DA Expansion.

CalCCA is the statewide organization of Community Choice Aggregators ("CCAs").[1] California's 19 operational CCAs served an annual load of approximately 44,400 GWh in 2019, or about one quarter of the load served within the service territories of California's three largest investor-owned utilities ("IOUs").[2] As of September 2019, CalCCA members have entered into a collective 3,400 MW of agreements for new renewable generation, energy capacity, and battery storage facilities in furtherance of California's leading and vital climate, air pollution and reliability goals.[3] CalCCA appreciates this opportunity to submit post-workshop comments on the Energy Division's January 8, 2020 workshop ("January 8 Workshop"). That workshop solicited input on an Energy Division study that will inform the Commission's recommendations to the

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1 CalCCA's members include: Apple Valley Choice Energy, Clean Power Alliance of Southern California, Clean Power San Francisco, Desert Community Energy, East Bay Community Energy, King City Community Power, Lancaster Choice Energy, Marin Clean Energy, Monterrey Bay Community Power, Peninsula Clean Energy Authority, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, Solana Energy Alliance, San Jacinto Power, San Jose Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy Alliance.

2 *See* California Energy Commission, Load-Serving Entity and Balancing Authority Forecasts, Form 1.1c, submitted Feb. 5, 2019, available at: https://ww2.energy.ca.gov/2018_energypolicy/documents/cedu_2018-2030/2018_LSE-BAF.php.

3 A full list of CCA contracts is attached as Appendix A.

Legislature regarding further direct access ("DA") expansion. CalCCA was an active participant in that workshop, with CalCCA representatives appearing on each of the workshop panels.

SB 237 recognizes the importance of doing no harm to ongoing climate, environmental, reliability, and cost-equity initiatives by requiring that any recommendations concerning expansion of DA satisfy the following criteria:

(1) the recommendations are consistent with the state's greenhouse gas ("GHG") emissions reduction goals;

(2) the recommendations do not increase criteria air pollutants and toxic air contaminants;

(3) the recommendations ensure electric system reliability; and

(4) the recommendations do not cause any undue cost shifting between bundled and DA customers.

As discussed at the January 8 Workshop, and in these comments, DA expansion now will almost certainly harm the state's ability to meet its GHG goals, will increase criteria air pollutants/toxic air contaminants, will undermine system reliability, and will result in undue cost shifts to bundled and CCA customers from commercial and industrial customers taking DA.

As highlighted in the work that the Commission's Policy and Planning Division ("PPD") performed in the Customer Choice Project,[4] and as experience in California and in other states highlights further, retail choice entails numerous structural issues for policymakers seeking to achieve environmental and reliability goals. Moreover, California's policy regime is undergoing a significant transition as the state moves to Integrated Resources Planning ("IRP") – encompassing numerous load serving entities rather than primarily focusing on the three large IOUs – and significant potential changes to the resource adequacy ("RA") market, including discussion of a central buyer for RA resources. PG&E's bankruptcy further exacerbates

[4] *See* https://www.cpuc.ca.gov/customerchoice/

uncertainty during this transition period. All of this must be factored into any recommendations on DA expansion, as too must consumer protection concerns.

In light of these concerns, the best recommendation – indeed, the *only* recommendation, given the paucity of the record here – the Commission can make to the Legislature now is to defer expansion of DA until appropriate mechanisms are in place to ensure California's continued climate leadership. Without a deferral to ensure these issues are sorted out, California's electricity market will most likely rapidly backslide on progress being made in emission reductions, reliability markets, and consumer protections.

II. DA Expansion Cannot Currently Be Squared with SB 237's Mandates.

SB 237 poses questions about Energy Service Providers ("ESPs") collectively, not about any one ESP. We recognize, as discussed by CalCCA representatives at the workshop, that there is significant diversity among ESPs serving California's nonresidential DA customers. Some ESPs and their customers are reducing GHG emissions from the electric sector ahead of legal requirements and contracting for development of new renewable resources. However, most are not. These comments address the issues associated with the collective practices of ESPs and the considerations the Commission must undertake associated with broader potential load migration to DA. They are not intended to describe any particular ESP or ESP practice, unless specifically noted.

Several workshop participants pointed to the existence of retail competition in other states to support assertions that DA can and should be expanded in California. CalCCA encourages Energy Division Staff to look very closely at challenges created by ESPs in other states with retail choice. For example, just this past December, New York enacted "significant reforms to the retail energy market" after a three-year investigation revealed many troubling ESP practices in the small commercial and residential retail markets. According to the New York Public Service Commission:[5]

> The record establishes that many of the concerns raised by the non-ESCO parties about the current operation of the retail access market are warranted. The Commission shares those concerns, particularly regarding the lack of easily accessible and comprehensible product and pricing information and, the number of complaints alleging that bad-acting ESCOs[6] were misleading and exploiting customers. Thus, we conclude that significant changes to provisions governing retail access are needed to provide adequate protections for New York customers. **If market participants are unwilling, or unable, to provide material benefits to customers beyond those provided by utilities in exchange for a regulated, just and reasonable rate, the market serves no proper purpose and should be ended.**

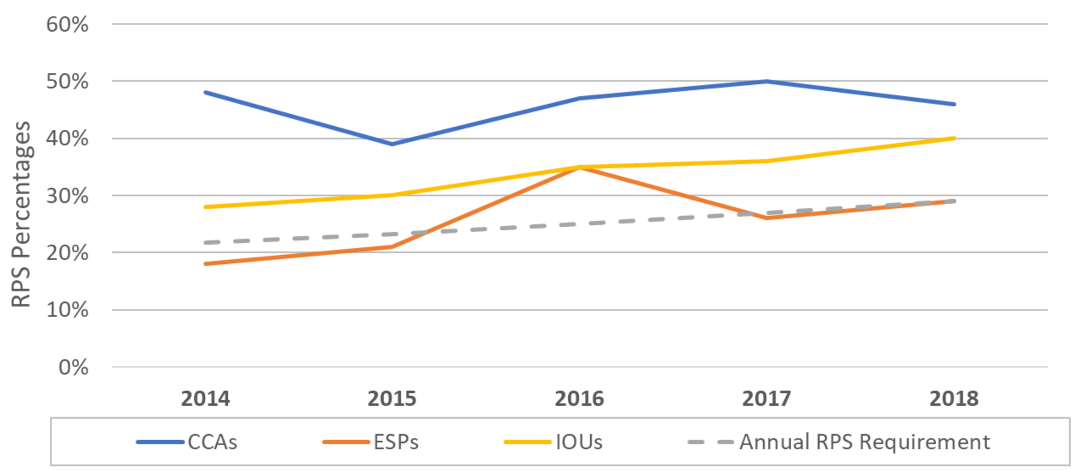
The major takeaway from California's and other states' experiences is that expanding customer-specific retail competition presents structural challenges to, among other things, development of new renewable resources. To square customer-specific retail competition under short-term contracts with achieving environmental and reliability goals, other states have adopted market and regulatory structures that are materially different from California. In particular, other states have market features that California does not (e.g., centralized capacity markets and a central long-term buyer for RECs in New York; an energy-only market in Texas). These states have taken different approaches than California in evolving their retail markets, and they have faced and addressed issues with which California is only now coming to grips. Notably, however, while these states' market features may mitigate some of the more challenging structural issues associated with retail choice, these states are *still* having problems with retail choice.

5 State of New York Public Service Commission, *Order Adopting Changes to the Retail Access Energy Market and Establishing Further Process*, Case nos. 15-M-0127, 12-M-0476, and 98-M-1343 (December 12, 2019) ("NYPSC Order") at 12 (emphasis added). Available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-M-0127&submit=Search

6 ESCOs are energy service companies that are akin to energy service providers in California.

During the January 8 Workshop, parties repeatedly highlighted the need for market structures to prevent "backsliding"[7] on the State's climate, environmental, reliability, and cost equity goals. CalCCA believes the State will see short-term and long-term forms of environmental backsliding if DA is expanded without any further market changes. In the short-term – incumbent load-serving entities ("LSEs") have been procuring RPS and GHG-free resources beyond minimum requirements. ESPs by and large have not. The following graphic shows the difference in environmental emphasis in historic ESP RPS compliance practices compared to other LSEs.[8]

Figure 1. Average Actual LSE RPS Percentages (2014-2018)



In a reopening scenario, customers will shift from "greener" incumbent LSEs (the blue and yellow, upper, lines) to "browner" ESPs (the lower, orange, line). All else equal, this will increase GHG and criteria pollutant emissions versus a continuation of the status quo. At the workshop, a DA advocate took issue with this contention, asserting that new DA customers might opt for greener products than current DA customers do. However, nothing in the historical record of ESPs

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7 By "backsliding", we mean an increase in GHG or criteria pollutant emissions versus a base case where there is no DA expansion and customers continue to be served by their incumbent providers, and or where IOUs continue to be displaced by greener CCAs.

8 *See* California Public Utilities Commission, *2019 California Renewables Portfolio Standard Annual Report, Tables 2, 4 and 6* (Nov 2019).

to date suggests it is likely that customers leaving incumbents for ESPs will *en masse* choose products as green as those of their prior supplier.

Turning to the longer-term impacts of DA expansion on achieving California's GHG-reduction goals, the dots here are more numerous but still easy to connect. Project developers need "financeable" LSEs to sell to in order to get lenders to provide the funds needed for new construction. LSEs, for their part, need assurance of a revenue stream for the duration of any power purchase agreement ("PPA") with a project developer. PPAs for new construction are long duration, generally fifteen years or more, and a developer needs to know its counterparty will be able to stand behind a PPA for that duration of the contract. In an era of declining prices, today's bargain is tomorrow's stranded cost. LSEs are well aware of this phenomenon, and so want such deals only if they are "back-to-back" with their retail sales arrangements. And therein lies the rub. Developers need decade-plus long deals, while in a competitive market environment LSEs would have no assurance of keeping customers for that long, at rates that would cover a PPA's costs. **The mismatch between the duration developers need in a contract for a new project, and the length of time an LSE can be confident of having a given load at a given price is a structural impediment to new project development in any market with retail competition.**

Expanding DA in the absence of market rules that prevent backsliding on the state's policy goals would be extremely detrimental to CCAs, to our contractual counterparties, and to our customers. Under a full DA expansion, CCAs could lose a significant percentage of load. Extreme levels of load instability threaten to undermine the long-term contracts that CCAs have already entered.[9] This brings us to the "death spiral" scenario. Consider an LSE locked into long-term

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[9] *See*, *e.g.*, D.19-02-022 at 16 ("an LSE who experiences load migration may be potentially stranded with these resources and costs.")

fixed price contracts that consequently ends up with higher prices than competitors. Stuck with high wholesale costs, that LSE raises retail prices. Customers leave. Those expensive contracts' costs now have to be recovered over a smaller customer base. That LSE raises prices further. More customers leave. Eventually not enough customers are left to pay counterparties, and that is the end of that LSE. And likely of the generator(s) on the other side of that LSE's PPA(s). Furthermore, credit markets will take note of this mismatch and finance projects at a higher interest rate, resulting in higher prices and lower affordability. Expanding DA without providing risk limiting options to current non-IOU LSEs will certainly raise the price of power to all customers, as suppliers factor a risk premium into their PPA and other energy-contract prices.

We hasten to add that this is a risk, not a certainty, associated with DA expansion. CCAs are taking and will continue to take steps to avoid it coming to pass. And we add further that the Commission can address this risk in a variety of ways, including an indifference adjustment for all LSEs. But what is certain is that, faced with this scenario, and absent Commission action to mitigate risks, *all* LSEs are going to be less likely to enter contracts, or as many contracts, for new capacity.[10] This is true notwithstanding that, beginning in 2021, 65% of a retail seller's RPS-eligible procurement must come from long-term procurement contracts with delivery terms of 10 years or more.[11] This long-term contracting requirement may have been intended to push CCAs and other LSEs to enter long-term contracts for new development, but what we heard at the January 8 Workshop is that there is a push among ESPs to do financial rather than physical deals, with contractual offramps that effectively defeat the purpose of this requirement.

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[10] *Id.* at 16 ("The uncertainty around load migration discourages LSEs from procuring too far out given that they do not know if they will have a particular set of customers in the future.")

[11] *See* Pub. Util. Code § 399.13(b).

We cannot emphasize the outcome here strongly enough, and so will say it again. **The mismatch between the duration developers need in a contract for a new project, and the length of time an LSE can be confident of having a given load at a given price is a structural impediment to new project development in any market with retail competition.** PPD recognized this issue in the Commission report titled, *California Customer Choice - An Evaluation of Regulatory Framework Options for an Evolving Electricity Market*, issued August 2018 (the "Green Book"). Key question No. 4 in Table 6 calls the question: "How does the choice model leverage investment necessary to finance the evolution of the electric grid?"[12] Beneath this question lay further questions:

- What entity makes the necessary large capital investments to operate the grid? Upon what authority?
- In what timeframe are investments being made?
- Is there an intentional shift of investment responsibility from the incumbent utility to other parties?
- What investment risks are anticipated and how are they being mitigated?
- What is the model for LSEs other than the IOUs and private entities to raise private capital/secure loans for new build/new generation (e.g. established credit worthiness, viable rate of return)?[13]

PPD raised similar questions yet again in the report titled, *California Customer Choice Project - Choice Action Plan and Gap Analysis*, issued December 2018 (the "Gap Analysis").[14] These questions remain unanswered today. These are but a few of the unanswered questions from the Green Book and the Gap Analysis that are germane to the first SB 237 criteria: that any expansion

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12 Green Book at 29.

13 *Id.*

14 *See* page 75 ("In the future, it is unclear whether capital investment necessary for new generation to meet the state's 2030 goals and beyond can be financed and, if so, delivered on time if the market evolves from a few larger buyers (IOUs) to many small buyers (CCAs, ESPs, and IOUs).")

must be "consistent with the state's greenhouse gas emissions reduction goals." Until and unless the Commission acts to address these issues, an expansion of DA threatens the new project development pipeline and will increase the cost of new developments as developers include a risk premium to cover this regulatory uncertainty, thus inhibiting achievement of SB 100 goals.

In sum, the Commission should not recommend that the Legislature undertake any further DA reopening until key prerequisites to this significant policy move are resolved. First and foremost, key and complex market structuring questions must be settled and implemented. Where we are going as a state should be addressed in a formal proceeding in concert with Legislative action, and as a result of conscious decision-making. Expansion of DA should not be the result of a rushed six-month process with virtually no record development. The track record of DA in this and other states raises red flags, and certainly does not provide a basis for the Commission to find that a further DA expansion is consistent with California's environmental and reliability policies.

III. Based on the Actions of ESPs to Date, an Expansion of Direct Access Is Inconsistent with California's Greenhouse Gas Emissions Reduction Goals.

SB 237 requires the Commission's recommendation regarding any further DA expansion to be consistent with achieving California's GHG emission reductions goals.[15] To reach a finding on GHG impacts, Section 2.1.1 of the Scoping Memo states that the Commission "will determine whether the recommendations are consistent with its RPS and IRP programs."[16] For the reasons discussed below, ESP's RPS compliance history and proposed future RPS procurement make such a determination impossible.

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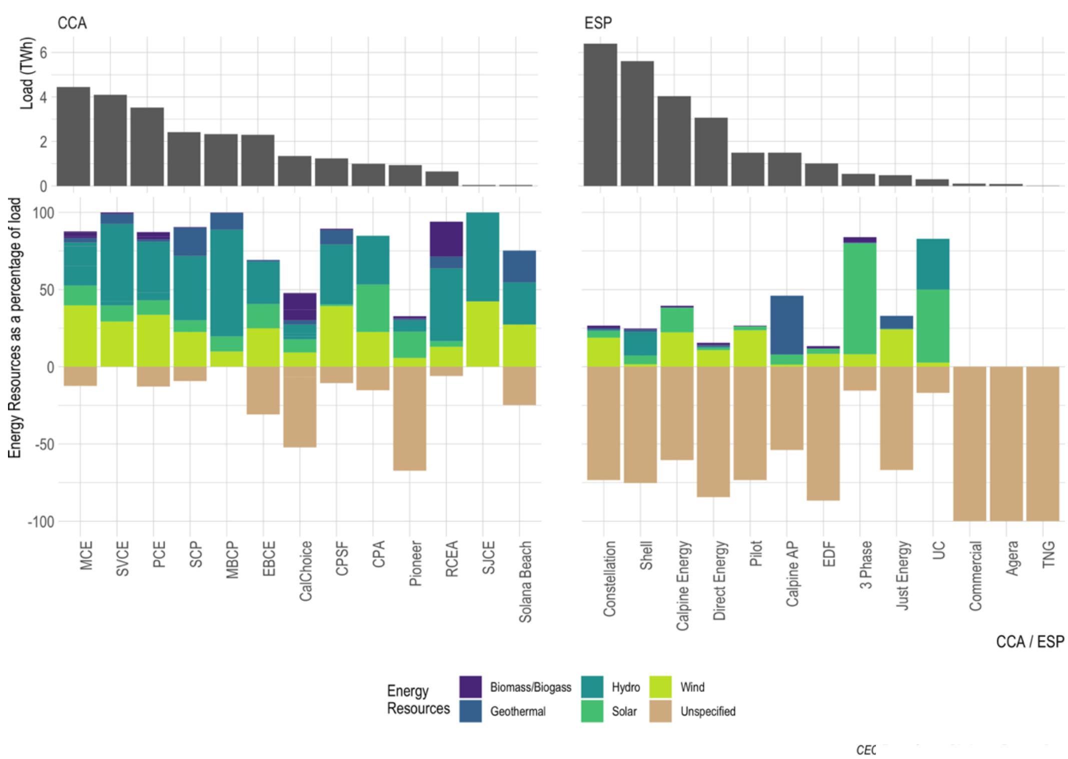
15 Pub. Util. Code § 365.1(f)(2)(A).

16 Scoping Memo at 5.

First, ESPs procure less RPS-eligible energy as a percentage of retail sales than CCAs and IOUs. Given this, any aggregate shifting of load from IOUs or CCAs to ESPs means more Californians will receive an energy supply with a higher carbon content that undermines the state's GHG goals and increases criteria air pollutants and toxic air contaminants. This is demonstrated in **Figure 2** below, which uses Portfolio Content Label ("PCL") data to show that, while ESPs have taken diverse approaches to RPS compliance, they are much "browner" as a whole than IOUs and CCAs, with the largest ESPs being among the "brownest." The top of Figure 2 below shows the load of each CCA and ESP and the bottom of Figure 2 plots the energy sources of each CCA and ESP as a percentage of total load served.[17]

Figure 2. 2018 Energy Resource Mix for California CCAs and ESPs



[17] This publicly available data comes from the California Energy Commission's 2018 Power Source Disclosure Program that discloses the historical contracted volumes by fuel type.

The differences in ESP and CCA energy supplies highlighted in Figure 2 lead to very different carbon intensities (and also to very different levels of emissions of criteria air pollutants and toxic air contaminants). For example, using the PCL data from Figure 2 and applying an emissions rate of 0.428 MT CO_2/MWh[18] to unspecified and natural gas-fired sources of generation, ESPs' carbon intensity averaged 0.207 MT CO_2/MWh in 2018 while CCAs' carbon intensity averaged 0.044 MT CO_2/MWh. As a result, each ESP on average emitted 510,103 tons of CO_2 in 2018, while each CCA on average emitted 82,172 tons of CO_2. In fact, even though CCAs serve significantly more load than ESPs, ESPs still emitted a total of 5,101,027 tons of CO_2 in 2018, which is almost five times the amount of CO_2 that CCAs as a whole emitted (1,068,239 tons of CO_2). This data is summarized in **Figure 3** below.

Figure 3. 2018 CO_2 Emissions for California CCAs and ESP

	Carbon Intensity (MT CO_2/MWh)	**Average CO_2 Emissions (Tons)**	**Total CO_2 Emissions (Tons)**
CCAs	0.044	87,172	1,068,239
ESPs	0.207	510,103	5,101,027

As a result of the different carbon intensities of ESP and CCA energy supplies, any load shifting from CCAs to ESPs, all else equal, will increase aggregate GHG emissions in California.

Second, ESPs as a whole have consistently failed to achieve minimum RPS compliance levels in any compliance period to date. Accordingly, any load shifting from CCAs to ESPs, all else equal, will increase the likelihood that California will not achieve its RPS goals. Six ESPs were deemed noncompliant in compliance period ("CP") 1 (2011-2013).[19] Three ESPs were

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18 California Air Resources Board default emissions factor utilized in its Cap-and-Trade Regulation. *See* 17 CCR § 95111(b)(1).

19 *See* California Public Utilities Commission, *2019 California Renewables Portfolio Standard Annual Report* at 24 (Nov 2019).

deemed noncompliant in CP 2 (2014-2016).[20] Two of these three were found to be non-compliant because they did not meet the long-term contracting requirements.[21] The deficit from these non-compliant ESPs was sufficient to pull ESPs as a whole below the minimum attainment threshold.

Third, ESPs have demonstrated limited commitment to entering long-term contracts to facilitate new RPS project development in California. Although developers need long-term contract commitments to finance new construction, many ESPs' procurement practices are inconsistent with the long-term commitments that developers need. For example, the Commission found in its decision on 2019 RPS procurement plans that ESPs have historically relied on short-term contracts to meet RPS requirements.[22] Consistent with this observation, in the most recent compliance period CP 2 (2014-2016), half of ESPs[23] met existing long-term contracting requirements[24] entirely through long-term agreements for unbundled RECs, not for new construction.[25]

If we look to the report titled *2019 California Renewables Portfolio Standard Annual Report*, we see virtually no plans by ESPs to procure from newly constructed projects.[26] Moreover, as TURN noted at the January 8 Workshop, no LSE has yet complied with the new 65% long-term contracting requirement that becomes effective in 2021. Although the data necessary to fully

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[20] *Id.* at 25.

[21] *Id.*

[22] *See* D.19-12-042 at 9.

[23] 7 of 14 ESPs that submitted public RPS Compliance Reports in 2018. Includes data from 2017 for UC Regents and Commercial Energy of California, as 2018 reports for these LSEs were not available on the CPUC's RPS Compliance Report archive at ftp://ftp.cpuc.ca.gov/RPS_PPAs/Compliance%20Report%20Archives/

[24] Equal to 0.25% of retail sales in the prior compliance period. See D.12-06-038 at 40.

[25] From 2018 RPS Compliance Reports, Unique Inputs Tab. ESPs reporting use of long-term agreements with PCC 3s to meet requirements include 3 Phases Renewables, Agera Energy, Commercial Energy of CA, EDF Industrial Power Services, Just Energy Solutions, Shell Energy North America, and Tiger Natural Gas.

[26] *See*, *e.g.*, California Renewables Portfolio Standard Annual Report, November 2019.

understand the level of ESP non-compliance with existing RPS requirements, including long-term contracting, is largely confidential, given what is available, the Commission should be concerned. For example, the Commission found in a recently issued decision regarding 2019 RPS Procurement Plans that:

> …many of the ESP RPS Plans provided minimal information, while some used boilerplate language that lacked adequate detail … [and] … while most ESPs note that they will meet the long-term contracting requirements, few actually explain how they plan to meet the requirement or show that they have executed long-term contracts.[27]

It is illustrative that Commercial Energy's representative explained in detail at the January 8 Workshop that it would be illogical for ESPs to enter into long-term contracts to serve short-term commitments from customers. Commercial Energy's reluctance to enter long-term contracts is illustrative of the broader concerns that competitive markets present for would-be investors in (and would-be purchasers from) new RPS projects.

In response to ESP and large commercial customer perspectives expressed at the January 8 Workshop that the Commission should set the rules and enforce them, TURN raised an important point: the Commission is just now issuing decisions enforcing noncompliance with RPS Compliance Period 2, which covers the period 2014-2016. This extreme lag means that the Commission does not have a rapid means of controlling LSE performance. In light of the urgent reliability concerns expressed in the most recent IRP decision and the urgency of the climate crisis, current enforcement mechanisms are insufficient to support a further DA opening consistent with the required statutory findings.[28]

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27 *See* D.19-12-042 at 55.

28 D.19-04-040 at 150-151.

Because ESPs are procuring more brown power than other LSEs, it would be unreasonable for the Commission to make the finding that a further DA expansion will be consistent with the state's GHG emission reduction goals. Accordingly, the Commission should recommend that DA not be further expanded at this time because the only available data shows that, historically, ESPs have procured less RPS-eligible supply.

IV. Based on Publicly Available Data, it is Clear that Load Migration to Direct Access Will Increase Emissions of Criteria Air Pollutants and Toxic Air Contaminants.

SB 237 requires that any further DA expansion must not increase emissions of criteria air pollutants and toxic air contaminants.[29] To reach a finding on criteria air pollutants and toxic air contaminants, Section 2.1.2 of the Scoping Memo states that the Commission will determine "whether the recommendations are consistent with its IRP program among other issues…".[30]

The same dynamics impacting GHG emissions will also impact criteria pollutant emissions. A shift from "greener" suppliers to "browner" ESPs will, all else equal, increase criteria pollutant emissions. Moreover, consistency with the IRP, by itself, is not sufficient for the Commission to reach the required finding that any further DA expansion must not increase emissions of criteria air pollutants and toxic air contaminants. The required finding in PUC Code 365.1(f)(2)(B) is binary: the Commission's recommendation regarding whether to expand DA *must not increase criteria air pollutants or toxic air contaminants*. There is no qualifier in the statutory language. In contrast, the IRP statutes require the Commission to ensure that LSE IRP Plans will "*minimize* localized air pollutants with early priority to disadvantaged communities."[31] Minimizing localized air pollutants, as the IRP statutes require, is not the same as SB 237's

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[29] Pub. Util. Code § 365.1(f)(2)(B).

[30] Scoping Memo, page 6.

[31] Pub. Util. Code § 454.52(a)(1(I) (italics added).

requirement that the Commission's recommendations *must not increase criteria air pollutants or toxic air contaminants*. Simply put, minimizing and not increasing are not the same. Accordingly, consistency with the IRP, by itself, is not sufficient for the Commission to reach the required statutory finding regarding criteria air pollutants and toxic air contaminants.

CalCCA understands that the Commission has access to data on each resource relied upon by each LSE in its IRP filing and can tie data on criteria air pollutant and toxic air contaminant emissions from IRP filings in the ARB's Facility Search Tool.[32] Doing so will shed light on the historic contributions to these emissions by resources on which ESPs rely to serve load. CalCCA recommends that the Energy Division use this approach in determining whether DA expansion could increase criteria air pollutants and toxic air contaminants, rather than relying solely on ESP compliance with IRP requirements.

Based on RPS compliance data discussed in the preceding section, ESPs are procuring more brown power than other LSEs. Because brown power causes more emissions of pollutants, it is highly likely that expanded DA will lead to more emissions of criteria pollutants and toxic air contaminants. Thus, based on the collective record of ESPs, the Commission cannot recommend any further expansion of DA at this time consistent with the required statutory findings that DA expansion must not increase criteria air pollutants or toxic air contaminants.

V. In Light of Recent Decisions and Significant Policy Uncertainty, the Commission Cannot Reasonably Find that Any Scheduled Reopening of Direct Access Would "Ensure" Electrical System Reliability.

SB 237 requires that any further DA expansion must "ensure" electric system reliability.[33] To reach a finding on the impacts of DA expansion to system reliability, Section 2.1.3 of the

32 https://ww3.arb.ca.gov/ei/disclaim.htm

33 Pub. Util. Code § 365.1(f)(2)(C).

Scoping Memo states that the Commission will "determine whether the recommendations are consistent with its RA and IRP programs and Section 451."[34]

California's RA market is undergoing significant change, transitioning from a fluid RA market to one characterized by tightening supplies and possible market power issues. For example, in the report titled *State of the Resource Adequacy Market – Revised*, which was circulated in R.17-09-020 on January 14, 2020, Energy Division Staff noted that the RA market is "tight," citing System, Local and Flexible RA deficiencies in 2019 and year-ahead deficiencies for 2020.[35] Although this report did cite unused capacity on the system level, it noted that there may be compliance issues for local capacity, especially in light of recent policy changes regarding Net Qualifying Capacity values.

The California capacity markets are in a further state of flux due to the Commission's signaling that it may shift to a central procurement model. The Commission and other state agencies are currently attempting to study and modify the existing RA and IRP processes to ensure that they can ensure reliability, and increased market complexity appears to be the reason for the top-down, prescriptive approach applied in setting the Preferred System Portfolio in the IRP Proceeding. Increased market complexity was also cited by the Commission as a principal reason for the need for central procurement in the RA proceeding.[36] That proceeding is still ongoing and significant uncertainty remains as to the market structure that the Commission will ultimately

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[34] Scoping Memo, page 6.

[35] R.17-09-020 Assigned Commissioner's Ruling on Energy Division's Resource Adequacy State of the Market Report, Appendix A at p. 40 ("In 2019, 11 LSEs had year ahead local deficiencies, six had year ahead system deficiencies, and five had year ahead flexible deficiencies, and many of these deficiencies persisted through the year in month ahead filings. **In addition, some LSEs reported being unable to identify available capacity at any price.** … This trend continued in the 2020 year ahead filings, in which, preliminarily, 20 LSEs had year ahead local deficiencies, five had year ahead system deficiencies, and four had year ahead flexible deficiencies.") (bolding added).

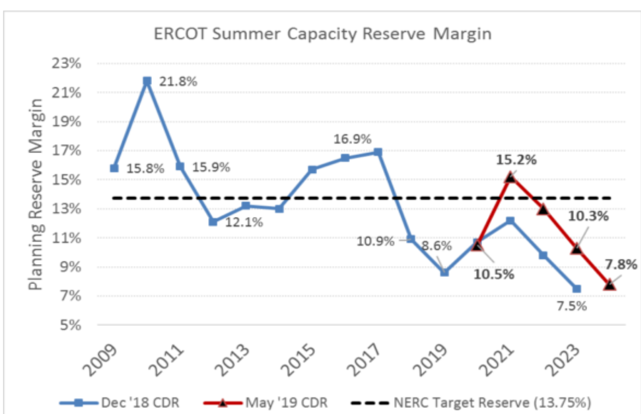
[36] R.17-09-020 Energy Division Staff Proposal "Current Trends in California's Resource Adequacy Program Energy Division Working Draft" (February 16, 2018) at 42-52.

adopt. Whether the processes that emerge will ensure reliability in a world of expanded DA and increased load migration cannot be answered until these policies are settled.

The Commission's urgent concern in Decision ("D.") 19-11-016 – which required an additional 3.3 GW of new System RA outside of the normal RA planning cycles – was to address a potential reliability shortfall by 2021 and is implemented over the 2021-2023 cycle. Procurement from D.19-11-016 will likely be the first test of whether existing LSEs can respond to Commission procurement directives aimed at ensuring reliability. The results of this procurement will be an important indication of how well different LSEs will comply with procurement directives to ensure reliability that the Commission determines is needed. ESPs have not been planning for additional load migration, and thus their ability to procure sufficient long-term contracts to supply large amounts of additional load in the near term in compliance with D.19-11-016 is unlikely.

Texas is an object lesson in the risks to reliability that can flow from not having any form of capacity market, centralized procurement, assurances of cost recovery, and/or other guardrails to ensure new construction remains on track. As **Figure 4** shows, new construction in Texas has not kept pace with load growth, and reserve margins have dropped accordingly:

Figure 4. ERCOT's Summer Capacity Reserve Margin: 2019-2023[37]



37 ERCOT, Seasonal Assessment of Resource Adequacy Report (SARA), as reported in a Constellation Energy Blog: https://blogs.constellation.com/energy-management/ercots-preliminary-summer-2019-assessment-a-declining-reserve-margin/

Moreover, this past summer, Texas wholesale spot-market prices spiked to the capped maximum of $9,000/MWh.[38] The Texas view is that this will lead to the construction of needed new capacity. Perhaps that will work. Regardless, this is a real-world example of underinvestment in capacity associated with a "pure" competitive environment, and California does not have the pricing mechanisms that Texas does to even potentially spur new investment.

Given the uncertainty regarding numerous RA issues, not the least of them the central buyer structure and identity, it is currently impossible for the Commission to make clear predictions of the impacts of DA expansion, and thus the Commission cannot recommend further DA reopening at this time consistent with a finding that such reopening will "ensure electric system reliability."

VI. Any Expansion of Direct Access Will Cause Undue Cost Shifting to Bundled Customers.

SB 237 requires that any further DA expansion must not cause undue shifting of costs to bundled service customers of an electrical corporation or to direct transaction customers.[39] To reach a finding on the potential for DA expansion to increase cost shifting, Section 2.1.4 of the Scoping Memo states that the Commission will determine "whether the recommendations are consistent with the PCIA and other mechanisms for ensuring the fair allocation of costs."[40]

Although the PCIA protects bundled customers from cost shifts that may result from IOU load departure, it does not prevent undue costs shifts to CCA customers. PUC Code Section 365.1(c) and other statutes make clear that Commission policies must ensure indifference more

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[38] https://www.reuters.com/article/us-texas-power-demand/texas-power-prices-briefly-soar-to-9000-mwh-as-heat-wave-bakes-state-idUSKCN1V41HV.

[39] Pub. Util. Code § 365.1(f)(2)(D).

[40] Scoping Memo, page 7.

broadly.[41] Ensuring indifference more broadly is critical to ensuring that *no* customer is harmed by further DA expansion, including CCA customers. Bundled customers are well protected via the PCIA and requirements that all non-IOU LSEs post a bond to cover potential costs associated with a mass return of load to the IOUs. On the other hand, customers served by CCAs do not enjoy those protections and could experience cost shifts as a result of DA expansion.

The Phase 1 decision in this proceeding addressed the ability of LSEs to impose exit fees to prevent undue cost shifting.[42] However, CalCCA requests confirmation from the Commission that current rules are sufficient to allow a CCA to collect an exit fee from departing customers. In particular, the Commission should evaluate Electric Rule No. 23 ("Rule 23") and whether it is currently sufficient to enable a CCA to recover an exit fee implemented by a CCA as a mechanism to protect its customers from cost shifts due to DA expansion.

To further limit cost shift impacts, the Commission should also consider general switching rules applicable to all providers (IOUs, CCAs, ESPs) to ensure that switching is orderly and affords LSEs opportunities to adjust their resource portfolios and procurement plans to accommodate customer migration. Switching rules worth consideration include potential enrollment periods and/or minimum stay obligations. Comprehensive load switching rules applicable to all LSEs are needed to ensure orderly and efficient migration of customers. CCAs are subject to such rules when they form or expand so that the IOUs can adjust their procurement and programs appropriately. Rules must be developed that will allow CCAs and DA providers to plan for load migration before significant additional load migration is allowed to occur.

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41 *See*, *e.g.*, Sections 365.2, 366.2(a), 366.3, 380(b), and 454.51(d).

42 D.19-05-043, page 32 ("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.")

In light of the numerous unresolved issues outlined above, the Commission cannot reasonably recommend that the Legislature further expand DA because it cannot find that any such expansion would not cause undue cost shifting.

VII. The Commission Should Not Recommend a Further DA Expansion at this Time Due to Significant Consumer Protection Concerns.

Consumer protection is core to the Commission's responsibilities[43] and was identified as a significant concern in the Customer Choice Project.[44] Although the general assumption is that DA serves large and sophisticated industrial customers, PUC Code section 365.1(f)(2) seeks recommendations concerning expansion of DA to *all* non-residential load – non-residential load ranges from small, relatively unsophisticated energy users ("mom & pop" stores) all the way to companies with robust energy procurement departments. In restructured markets, small non-residential customers face the same consumer protection issues as residential customers.

In the Gap Analysis, the Commission raised concerns over how customers will be treated during a natural disaster if they are unable to pay their bill as a result of an extended Public Safety Power Shutoff event that prevents them from opening for business.[45] More generally, the Gap Analysis raised concerns with ensuring that consumers have high levels of protection during a natural disaster.[46] These issues should be addressed prior to any further expansion of DA. The Gap Analysis also raised concerns regarding slamming and cramming, asking "are rules in place sufficient to prevent slamming and cramming of unsophisticated business customers?"[47] This is a

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[43] See Pub. Util. Code § 394 *et. seq.*

[44] *See* Green Book at 7-9, 25, 62; Gap Analysis at 22-42.

[45] Gap Analysis at 9, 26, 29.

[46] *Id.* at 20.

[47] *Id.* at 36.

valid concern, as Richard Sedano of the Regulatory Assistance Project highlighted at the 2017 *En Banc* baiting and switching of customers that has taken place in New York.[48]

A more foundational question is whether small commercial customers understand the rate structures and terms of the contract that they are being offered? A recent example from Texas is illustrative, where small customers signed up for retail rates under promises of a low rate (energy savings). When wholesale prices spiked to $6000-9000/MWh, small businesses and residential customers saw their bills skyrocket.[49] Other research points to instances involving ESPs giving incorrect information regarding variable prices, giving incorrect information about contract cancellation, advertising that variable rates would not rise above standard service cost, providing teaser rates on long contracts that reset to much higher rates, charging high cancellation fees, and imposing automatic renewal of contracts.[50] The Commission should ensure that rules are in place to prevent such practices before the Commission can recommend a further DA expansion. Statutory prohibitions are not sufficient and need to be operationalized with clear rules and processes that protect small business customers.

In addition, the Commission must consider whether DA customers will be offered rate structures that are consistent with California's loading order, energy conservation policies, time of use, and other standards. Review of rate offerings in Texas shows many providers offering high

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48 https://centurylinkconferencing.webex.com/cmp3300/webcomponents/docshow/docshow.do?siteurl=centurylinkconferencing&mactype=Osx&rnd=0.9061442881993139

49 *See*, *e.g.*, https://www.dallasnews.com/news/watchdog/2019/08/23/texans-pay-more-for-electricity-now-than-other-major-markets-a-wholesale-price-record-is-to-blame/

50 See, Competing to Overcharge Consumers: The Competitive Electric Supplier Market in Massachusetts, Jennifer Bosco, National Consumer Law Center, April 2018. Available at: https://www.nclc.org/images/pdf/pr-reports/competitive-energy-supply-report.pdf. *See also* NYPSC Order (noting that adoption of new marketing standards "are the result of a gradual iterative process of increasing the specificity and restrictiveness of the applicable standards to ESCO marketing practices resulting from persistent, unacceptably high numbers of customer complaints alleging ESCO deceptive marketing.")

energy users bill discounts which lower their effective rate.[51] This pricing plan is counter to California's current rate structures and state policies designed to reduce energy use overall to further GHG emissions reduction goals, reduce emissions of criteria pollutants and toxic air contaminants, and as a core means of saving customers money.[52]

Finally, the Commission should consider whether customers will understand the GHG/renewables content of what their EPS is selling? For example, it appears that some ESPs provide zero renewable energy for the first two years of the RPS compliance period and then cover their needs with RECs and other resources in the final year.[53] In this situation, it is reasonable to ask – do current businesses understand that in Years 1 and 2 they are receiving brown system power? Would a small "mom and pop" business understand this situation? While this business model may be "compliant" with Commission rules concerning the RPS program, it is reasonable to conclude that the average small business owner would not understand the nuance of receiving brown system power for two out of three years of their contract. Moreover, depending on the term of the contract between the ESP and the small business, the small business owner could only receive brown power during their term of service with the ESP if it was shorter than the compliance period.

Each of these issues needs to be more fully assessed prior to any further DA expansion to ensure energy consumers are protected from predatory business practices. Until these issues are

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51 *See*, *e.g.*, https://www.comparepower.com. *See also* https://www.texaspowerguide.com/2017/reliant-high-use-plan/

52 *See* D.15-07-001 at 9-14.

53 For example, this is demonstrated on Figure 1 on page 7 of these post-workshop comments. Figure 1 shows ESPs procuring RPS-eligible energy below the annual RPS requirement for the first two years of CP 2 and then attempting to make up for the shortfall in the last year of the compliance period. *See also* RPS compliance reports of Commercial Energy.

resolved, it would be premature for the Commission to recommend that the Legislature further expand DA at this time.

VIII. Conclusion.

The Commission should recommend to the Legislature that DA transactions should not be further reopened at this point in time because the Commission cannot reasonably recommend *any* further DA expansion consistent with the findings it must make in PUC Code §365.1(f)(2), i.e. that any such expansion would (1) be consistent with California's GHG emission reductions goals, (2) not increase emissions of criteria air pollutants and toxic air contaminants, (3) ensure electrical system reliability and (4) not cause undue shifting of costs. Moreover, as outlined above, there are significant consumer protection issues that must be addressed and be capable of being mitigated before the Commission can recommend any further DA expansion. Accordingly, the Commission should recommend do further expansion of DA load at this time until the many significant issues above are resolved and the Commission has had a period of years to evaluate implementation and compliance with these policies.

Once the issues noted above are sufficiently addressed, in moving forward with any prospective DA reopening, the Commission and/or Legislature would do well to examine limited approaches that *could* allow further short-term retail competition without going backwards on emissions, and without freezing the project development pipeline. One possible approach could be to limit any prospective DA expansion to corporate PPAs "sleeved" through ESPs for <u>new 100% RPS projects</u>. The legislature is already exploring rules around such transactions in SB 702, so examining them first would be in step with legislative activity. There may be other "no regrets" steps that could be front-loaded; TURN made an off-the cuff proposal at the workshop, and we would be interested in learning more about such ideas if and when the Commission moves forward.

January 21, 2020

Respectfully submitted,

/s/ Kevin Fox

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APPENDICES

Appendix A: List of Contracts Executed by Community Choice Aggregators (CCAs)

CCAs New Renewable PPAs (current to 10-28-2019)								
CCA	Project Name	Technology	Nameplate Capacity (MW)	Nameplate Battery (MW)	Storage Capacity (MWh)	County	PPA Term (Years)	Year
Apple Valley Choice Energy	Mountain View III Wind Farm	Wind	5.0			Riverside	10	2021
Clean Power Alliance	Clearway/Golden Fields	Solar	40.0			Kern	15	2021
Clean Power Alliance	Nextera/Arlington	Solar	233.0			Riverside	15	2021
Clean Power Alliance	Nextera	Wind	300.0			Arizona	15	2020
Clean Power Alliance	Voyager Wind II Phase 4	Wind	21.6			Kern	15	2019
CleanPowerSF	Blythe Solar	Solar	62.0			Riverside	20	2020
CleanPowerSF	San Pablo Raceway	Solar	100.0			Los Angeles	22	2019
CleanPowerSF	Voyager IV	Wind	110.0			Kern	15	2020
CleanPowerSF	Maverick Solar 6	Solar	100.0			Riverside	20	2021
East Bay Community Energy	sPower	Solar + Storage	125.0	80.0	160	Kern	20	2022
East Bay Community Energy	Edwards Solar Project	Solar	100.0			Kern	15	2022
East Bay Community Energy	esVolta Oakland Clean Energy Initiative	Storage	7.0	7.0	28	Alameda	13	2021
East Bay Community Energy	Oakland Energy Storage 1	Storage	20.0	20.0	80	Alameda	10	2022
East Bay Community Energy	Sunrun Oakland Clean Energy Initiative	Storage	0.5	0.5	2	Alameda	10	2021
East Bay Community Energy	Luciana	Solar	56.0			Tulare	15	2021
East Bay Community Energy	Sonrisa Solar	Solar + Storage	100.0	30.0	120	Fresno	20	2022
East Bay Community Energy	Rosamond Solar Project	Solar	112.0			Kern	15	2021

East Bay Community Energy	Salka Wind	Wind	57.5			Alameda	20	2020
Lancaster Choice Energy	Western Antelope Dry Ranch	Solar	10.0			Los Angeles	20	2016
Lancaster Choice Energy	Montain View III Wind Farm	Wind	11.0			Riverside	10	2021
MCE	Hay Road Landfill	Biogas	1.6			Solano	20	2013
MCE	Ostrom Road Landfill	Biogas	1.6			Yuba	18	2013
MCE	Redwood Landfill	Biogas	3.5			Marin	20	2017
MCE	Lincoln Landfill	Biogas	4.8			Placer	20	2013
MCE	Small World Trading	Solar	0.1			Marin	20	2018
MCE	DRES Quarry	Solar	0.1			Marin	20	2017
MCE	Rawson Blum & Leon / Cost Plus Plaza	Solar	0.3			Marin	20	2016
MCE	San Rafael Airport II	Solar	1.0			Marin	20	2012
MCE	Oakley RV and Boat Storage	Solar	1.0			Contra Costa	20	2018
MCE	San Rafael Airport	Solar	1.0			Marin	20	2012
MCE	North Shore / Freethy 1	Solar	1.0			Contra Costa	20	2016
MCE	North Shore / Freethy 2	Solar	1.0			Contra Costa	20	2016
MCE	Silveira Ranch A	Solar	1.0			Marin	20	2019
MCE	Silveira Ranch B	Solar	1.0			Marin	20	2019
MCE	Silveira Ranch C	Solar	1.0			Marin	20	2019
MCE	American Canyon A	Solar	1.0			Napa	20	2019
MCE	American Canyon B	Solar	1.0			Napa	20	2019
MCE	American Canyon C	Solar	1.0			Napa	20	2019
MCE	Soscol Ferry Solar 2	Solar	1.0			Napa	20	2019
MCE	Soscol Ferry Solar 3	Solar	1.0			Napa	20	2019
MCE	Central Marin Sanitation Agency	Solar	1.0			Marin	10	2019
MCE	Dominion / Buck Institute	Solar	1.0			Marin	25	2016
MCE	Solar One	Solar	10.5			Contra Costa	20	2017

MCE	Little Bear 3	Solar	20.0			Fresno	20	2020
MCE	Cottonwood	Solar	23.0			Kings	25	2015
MCE	Mustang 4	Solar	30.0			Kings	15	2016
MCE	Little Bear 1	Solar	40.0			Fresno	20	2020
MCE	Little Bear 4	Solar	50.0			Fresno	20	2020
MCE	Little Bear 5	Solar	50.0			Fresno	20	2020
MCE	Desert Harvest	Solar	80.0			Riverside	20	2020
MCE	Great Valley 1	Solar	100.0			Fresno	15	2018
MCE	Antelope Expansion 2	Solar	105.0			Los Angeles	20	2018
MCE	Voyager II	Wind	42.0			Kern	12	2018
MCE	Strauss Wind	Wind	98.8			Santa Barbara	15	2020
MCE	Cooley Quarry 1	Solar	1.0			Marin	20	2017
Monterey Bay Community Power	BigBeau	Solar + Storage	58.0	18.0	72	Kern	20	2021
Monterey Bay Community Power	RE Slate	Solar + Storage	67.5	20.3	81	Kings	15	2021
Monterey Bay Community Power	Duran Mesa Wind	Wind	90.0			New Mexico	15	2020
Monterey Bay Community Power	Casa Diablo IV	Geothermal	7.0			Mono	10	2021
Peninsula Clean Energy	Mustang II Whirlaway	Solar	100.0			Kings	15	2020
Peninsula Clean Energy	Wright Solar Park	Solar	200.0			Merced	25	2019
Rancho Mirage Energy Authority	Montain View III Wind Farm	Wind	6.0			Riverside	10	2021
Redwood Coast Energy Authority	California Redwood Coast-Humboldt County Airport Microgrid	Solar + Storage	2.0	2.0	8	Humboldt	25	2020
San José Clean Energy	Sonrisa	Solar + Storage	100.0	10.0	40	Fresno	20	2022
Silicon Valley Clean Energy	BigBeau	Solar + Storage	70.0	22.0	88	Kern	20	2021
Silicon Valley Clean Energy	RE Slate	Solar + Storage	82.5	24.7	99	Kings	15	2021

Silicon Valley Clean Energy	Duran Mesa Wind	Wind	110.0			New Mexico	15	2020
Silicon Valley Clean Energy	Casa Diablo IV	Geothermal	7.0			Mono	10	2021
Sonoma Clean Power	Lavio Solar	Solar	1.0			Sonoma	20	2018
Sonoma Clean Power	Stage Gulch Solar	Solar	1.0			Sonoma	20	2018
Sonoma Clean Power	Cloverdale Solar Center	Solar	1.0			Sonoma	20	2019
Sonoma Clean Power	IP Malbec	Solar	1.0			Mendocino	20	2019
Sonoma Clean Power	Bodega Energy West	Solar	1.0			Sonoma	20	2019
Sonoma Clean Power	Petaluma Energy East	Solar	1.0			Sonoma	20	2019
Sonoma Clean Power	RE Mustang	Solar	30.0			Kings	20	2016
Sonoma Clean Power	RE Mustang 3	Solar	40.0			Kings	20	2016
Sonoma Clean Power	Proxima	Solar + Storage	50.0	5.0	10	Stanislaus	20	2023
Sonoma Clean Power	Golden Hills North	Wind	46.0			Alameda	20	2017
Sonoma Clean Power	Sand Hill C	Wind	80.0			Alameda	20	2021