New CPUC Regulation of Community Choice Aggregators

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I. INTRODUCTION

The structure of the California electricity market is changing rapidly due, in large part, to the sudden proliferation of Community Choice Aggregators (CCAs). Though CCAs were authorized by the state Legislature in 2002, immediately following the California electricity crisis, the first active CCA did not launch until 2010,[1] the second active CCA did not launch until 2014,[2] and CCAs did not begin launching in significant numbers until 2017.[3] Eleven CCAs are slated to begin operations by the end of 2018. Not only is the rate at which CCAs are launching increasing exponentially, but the newly operational CCAs serve significant geographical areas—and significant numbers of customers that used to get their electricity from Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, the large investor owned utilities (IOUs). The IOUs themselves predict that by 2025, close to 85 percent of customers in California could receive their electricity from a CCA or direct access provider.[4]

This shift does not just represent a shrinking customer base for the IOUs or an increase in customer choice. It means that the responsibility for ensuring that enough electricity is available to meet California's needs is rapidly being fragmented and spread among an increasing number of disaggregated entities. This decentralization is the driving force behind the unprecedented CCA regulations issued by the California Public Utilities Commission (CPUC) in 2017 and 2018. The CPUC has increased the number of requirements CCAs must meet and upped the level of participation in CPUC proceedings required of CCAs, but the most significant of these recent edicts is the mandatory one-year minimum freeze between CCA implementation and the date on which it can begin serving customers.[5] Not only did this rule change completely—and abruptly—the manner in which CCAs had been forming and launching, but it was a marked departure from the CPUC's longstanding refusal to exercise control over the

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[1] Marin Clean Energy.
[2] Sonoma Clean Power.
[3] Silicon Valley Clean Energy, Apple Valley Choice Energy, Redwood Coast Energy Authority, and Pico Rivera Innovative Municipal Energy.
[4] Joint Prepared Testimony of PG&E, SCE, and SDG&E, R.17-06-026, ch. 1, pp. 1-5 (line 26)–1-6 (line 2).
[5] Resolution E-4907.

actual operations of CCAs.[6]

Shortly after the CPUC imposed the one-year waiting period on new and expanding CCAs, it issued the Draft Green Book, titled *California Customer Choice: An Evaluation of Regulatory Framework Options for an Evolving Electricity Market*.[7] The introduction to the Green Book by CPUC President Michael Picker states the reason for the CPUC's sudden increase in CCA regulation and its efforts to get a handle on the emerging electricity market: "In the last deregulation, we had a plan, however flawed. Now, we are deregulating electric markets through dozens of different decisions and legislative actions, *but we do not have a plan. If we are not careful, we can drift into another crisis*."[8] The CPUC, driven by its fear of repeating the energy crisis of the early 2000s, is now trying to formulate a plan. That plan will necessarily include increased regulatory oversight of all market participants and increased responsibilities—operational and financial—for CCAs.

Cities and counties that are contemplating forming a CCA, joining an existing CCA, or expanding a CCA's service territory need a thorough understanding of CPUC jurisdiction, emerging regulations, and the history that informs those regulations. CCAs' statutory right to self-direct their procurement of electricity[9] and to operate free from CPUC micromanaging has been their lodestar when interacting with the agency. That autonomy is the very thing with which the CPUC is now reckoning. While the CCAs will not become fully regulated utilities under CPUC jurisdiction, they will not retain the operational flexibility they enjoyed until recently.

II. DIRECT AND INDIRECT CPUC REGULATION OF CCAS

Community Choice Aggregators exist in a regulatory twilight, neither fully regulated nor entirely free to do as they please. The CPUC has jurisdiction over the rates, operations, infrastructure, and policy decisions of privately owned electric utilities (the IOUs). CCAs are public entities and therefore not subject to full rate and operational

[6] See D.05-12-041, p. 9 ("Nothing in [Public Utilities Code section 366.2] directs the Commission to regulate the CCA's program except to the extent that its program elements may affect utility operations and the rates and services to other customers. For example, the statute does not require the Commission to set CCA rates or regulate the quality of its services.").
[7] Draft Green Book (May 17, 2018).
[8] *Id.* at p. iii (emphasis added).
[9] Pub. Util. Code § 366.2(a)(5)

regulation. But the CPUC does have control over certain aspects of CCA operations, directly and indirectly. CCAs must register with, and submit their implementation plans to, the CPUC before they begin serving customers; the CPUC recently issued a decision that formalized the requirement that new CCAs post a bond when they register.[10] The CPUC directly oversees CCA compliance with California's requirements to meet renewable energy targets (the Renewables Portfolio Standard or RPS). The CPUC also has authority to ensure that CCAs purchase enough energy to serve their customers under high-electricity-use conditions (Resource Adequacy or RA).

The CPUC exercises indirect control over CCAs through the investor owned utilities. While CCAs provide electricity to their customers, the IOUs provide the transmission, distribution, metering, and billing services to the CCA's customers. The CPUC's oversight of IOU tariffs and operations, which dictate the rates and terms under which the "wires" and administrative services are provided, affects CCAs and their customers. The IOUs are also entitled to recover the costs of energy purchased or infrastructure built on behalf of customers that subsequently left the IOU for CCA service. When CCAs were first authorized, these recoverable costs included the Department of Water Resources energy contracts that arose during the California energy crisis.[11] Now, the bulk of the costs are for renewable energy contracts that were executed in the early years of the renewable energy market. The requirement that CCA customers reimburse the IOUs for certain expenditures raises monthly electricity bills for CCA customers and affects the CCA's ability to charge lower rates than the IOU.

Community Choice Aggregators were authorized by the Legislature in 2002 in Assembly Bill 117. AB 117 enacted Public Utilities Code sections 218.3, 331.1, 366.2, 381.1, and 394.25 pertaining to CCA formation and operation; of these, section 366.2 is the most significant because it contains the framework for CCA formation and CPUC oversight. Section 366.2 contains three fundamental directives that are central to the issue of CPUC regulation of CCAs: (1) CCAs are solely responsible for procuring all

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[10] D.18-05-022, *Decision Establishing Reentry Fees and Financial Security Requirements for Community choice Aggregators* (June 7, 2018).

[11] See D.04-12-046, *Order Resolving Phase 1 Issues on Pricing and Costs Attributable to Community Choice Aggregators and Related Matters* (December 21, 2004), pp. 5–6.

the electricity necessary to serve their customers[12]; (2) the CPUC must determine the costs CCA customers have to pay to reimburse the incumbent utility for electricity it purchased or services it provided on behalf of the CCA customers it no longer serves,[13] in order to ensure the utility's remaining customers don't experience bill increases (or, that they remain "indifferent" to the CCA customers' departure); and (3) the CCA must submit to the CPUC its implementation plan, which must provide for universal access, reliability, equitable treatment of all customer classes, and any requirements established by state law or by the CPUC.[14]

The third directive is historically the most straightforward, but is also the mechanism through which the CPUC imposed the new requirement that CCAs wait at least a year between filing their implementation plans and beginning operations. The registration and implementation requirements were originally set by the CPUC in 2005.[15] Rejecting the IOUs' arguments that the CPUC had broad jurisdiction over all aspects of CCA operations, the CPUC determined that AB 117 did not give it authority to approve or disapprove a CCA implementation plan or any subsequent modifications.[16] Nor did the CPUC believe it had authority to dictate the contents of CCA implementation plans.[17] The CPUC concluded that CCA implementation plans were merely the mechanism by which the CCA provided the information necessary to receive the transmission, distribution, and billing services from the IOU.[18] The CCA submits its implementation plan and registration package to the CPUC; the CPUC certifies receipt within 90 days and provides the CCA with its cost responsibility for IOU expenses.[19] This hands-off approach was the rule for 12 years, until the CPUC proposed to impose a minimum one-year freeze before a CCA begins serving customers.[20] The purpose of this moratorium is to align CCA operations with the cycle on which load-serving entities (LSEs) are required to demonstrate that they have purchased enough electric capacity to serve all of

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[12] Pub. Util. Code § 366.2(a)(5).
[13] *Id.* at §§ 366.2(a)(4), (c)(5)–(8), (c)(20), (d)–(k).
[14] *Id.* at §§ 366.2(c)(4)–(5).
[15] D.05-12-041, pp. 4, 6–9, 12–18.
[16] *Id.* at pp. 6–9, 14.
[17] *Id.* at p. 16.
[18] *Id.* at p. 9.
[19] *Id.* at p. 12; see also Pub. Util. Code §§ 366.2(c)–(f).
[20] Draft Resolution E-4907 (issued December 8, 2017).

their customers on a high-use day.[21] Resolution E-4907 and CCA Resource Adequacy requirements are discussed in detail in Section IV, below.

The first and second directives—that CCA have total autonomy in buying electricity and that the CPUC must allocate IOU costs to CCA customers to ensure that remaining IOU customers don't pay more than they should—have dovetailed in the current issues the CPUC is attempting to sort out. CCAs' procurement autonomy has traditionally been a fact without significant policy or practical implications. The CPUC has jurisdiction to enforce CCAs' compliance with California's renewable energy procurement targets, with annual Resource Adequacy requirements, and with other specialized procurement requirements (like energy storage[22]), but the CPUC cannot bless the CCAs' Power Purchase Agreements or otherwise dictate where the CCAs' power comes from. The IOUs are subject to the same policy-driven procurement requirements, though the CPUC does review their energy contracts for reasonableness. But as CCAs are rapidly forming to serve customers that are already served by the IOUs, and for whom the IOUs have already bought power, the potential for significant double-procurement and significant IOU costs that must be paid by CCA customers has spurred the CPUC to reexamine the electric market structure[23] and existing cost allocation mechanisms.[24]

To understand the existing market structure into which CCAs are entering in record numbers, and to understand why this change has prompted the CPUC to increase its oversight over CCAs, it is necessary to understand the energy crisis of the early 2000s.

III. EVERYTHING OLD IS NEW AGAIN: THE CALIFORNIA ENERGY CRISIS

The process of forming California's current electricity market began in 1976, when the state Legislature opened the wholesale electric market to competition by passing legislation that allowed IOUs to purchase electricity from any private entity

[21] Res. E-4907, p. 10.
[22] D.13-10-040 (requiring CCAs to procure storage for 1% of their peak load).
[23] The Commission's current thinking on the electricity market in California is addressed in the Green Book section below.
[24] The question of how CCA customer responsibility for stranded IOU power costs is addressed in the section on the Power Charge Indifference Adjustment (PCIA).

producing renewable energy or using cogeneration.[25] Until that time, the IOUs were vertically integrated, meaning they owned the plants that produced electricity, the transmission and distribution systems that sent power out to customers, and were responsible for all metering, billing, and customer service. The IOUs were the only option for obtaining electricity, and they were the electricity "market" in California. Two years after the Legislature authorized the IOUs to purchase some of their power elsewhere, Congress passed the Public Utility Regulatory Policies Act of 1978 (PURPA)[26] in response to the Middle Eastern oil embargo, in order to diversify the country's fuel supply. PURPA *required* utilities to buy electricity at wholesale prices from non-utility generators that used cogeneration or renewable technologies that met certain qualifying criteria. In addition to mandating electricity procurement for the first time, PURPA changed the electric sector by requiring that the IOUs' wholesale purchases be at the utility's "avoided cost"—the price the utilities would pay for power "but for" the qualifying generator—in order to keep the IOUs' customers financially indifferent to where the power was coming from. PURPA also ensured that the third-party generators would be guaranteed access to the IOU-owned transmission grid so that the power they sold could actually be delivered.[27]

The CPUC contributed to the nascent wholesale electricity market by conceiving and adopting long-term power purchase agreements (PPAs or standard offers) that served as the contracts between the IOUs and the third-party generators. The most important aspect of the PPAs was their guaranteed long-term capacity payments, with 10-year fixed energy prices; this revenue stream allowed private capital investment in new generation projects to be essentially backed by the creditworthiness of the IOUs' balance sheets. The third-party generators built 10,000 MWs of electric generation to compete with the IOUs' in-house generation plants.[28]

In the early 1990s, pressure was mounting on Congress, the state Legislature, and the regulators to fully open the electric sector to allow competition in both supply *and* purchase, which was already the model in the natural gas, transportation,

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[25] Green Book, p. 63. Cogeneration uses a single fuel source to produce electric energy and a second form of energy, such as heat or steam, simultaneously or sequentially.
[26] 16 USC chapter 46, § 2601 et seq.; 18 CFR Part 292 *et seq.*
[27] Green Book, p. 63.
[28] *Id.* at pp. 63–64.

and telecommunications markets. The prevailing argument was that the electric power industry was no longer a natural monopoly and should be deregulated. Congress responded in 1992, passing the Energy Policy Act, which opened access to the IOU-owned transmission networks to independent energy producers and allowed them to enter into contracts for electricity with third parties. The Energy Policy Act also created a new category of electric generators that were not subject to regulation as a public utility.[29] By 1995, parallel courses of study and policy decisions in the Legislature and at the CPUC culminated in action by both entities that set in motion the deregulation of California's electricity market.

A. CPUC Deregulation Decisions

In 1993, the CPUC began studying California's existing electric market and regulatory structure, and began formal proceedings to restructure and reform its regulation of the electric industry for retail and wholesale customers. The CPUC ultimately decided on two courses of action: (1) customer choice would be implemented through Direct Access, which would allow customers to buy electricity directly from non-IOU retail sellers; and (2) the way utility rates were set would change. The CPUC's fundamental goal in restructuring the electric industry was to lower electricity bills without harming the IOUs' financial integrity. The IOUs would remain the providers of last resort and would continue to deliver electricity to all customers through the IOUs' distribution systems.[30] The CPUC's market and ratemaking study culminated in its Preferred Policy Decision, issued in 1995.[31] The Preferred Policy Decision articulated the CPUC's vision for customer choice and a competitive electricity market, which was set to launch on January 1, 1998.

While the IOUs would retain their "wires" and their obligation to serve the public as a last resort, in order to foster a true competitive market the CPUC provided incentives to the IOUs if they would voluntarily divest themselves of at least 50% of their generating plants (particularly fossil fuel plants). This paved the way for non-utilities to own or build their own electric plants. It also required the CPUC to address the fact that the IOUs were entitled to reimbursement for the costs of building and operating the plants

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[29] Green Book, p. 64.
[30] *Id.* at pp. 64–65.
[31] D.95-12-063.

they no longer owned.[32] Under basic utility ratemaking in California, an IOU recovers the costs to build and operate a generating asset over the course of the asset's depreciable life—generally in the neighborhood of 30 or 40 years. If the plant must be shut down or is sold to a non-utility before its depreciable life expires, the utility is still entitled to recover its costs for the plant. Costs a utility is entitled to collect for assets or contracts that are no longer serving its customers are "stranded costs." In order to ensure the IOUs recovered the stranded costs of their now-divested power plants, the CPUC created the Competition Transition Charge (CTC) to collect those costs from all customers, regardless of whether they stayed with the utility or switched to a Direct Access provider for electricity service.[33] To balance the IOUs' right to recover their costs and need to protect retail customers from sharp rate increases or fluctuations, the CPUC imposed a retail rate cap that was designed to last until 2005, the target date for the IOUs to finish divesting their generating assets.[34]

In addition to allowing customers to choose where their electricity came from, the CPUC directed that two new entities would be created to oversee the "free" market: the Independent System Operator[35] and the Power Exchange.[36] The new market structure, combined with the rate cap the CPUC imposed on IOU retail rates, contributed to the eventual collapse of the competitive electricity market.

B. <u>Legislative Restructuring—AB 1890</u>

Assembly Bill (AB) 1890 was introduced during the 1995 legislative session, before the CPUC adopted its Preferred Policy Decision, and was ultimately signed into law in September 1996.[37] AB 1890 incorporated the CPUC's creation of the Competition Transition Charge and its proposed market structure, but also accelerated the completion target for the deregulation process from 2005 to 2002.[38] AB 1890 mandated an immediate 10% rate reduction for residential and small commercial customers of the

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[32] Green Book, p. 67.
[33] Green Book, p. 67; see also D.95-12-063. The CTC applies to pre-1998 electricity contracts.
[34] D.95-12-056, 64 CPUC 2d 1, 236–237.
[35] This entity still exists and is now known as the California Independent System Operator (CAISO).
[36] Green Book, p. 66.
[37] AB 1890 (Brulte) (ch. 854).
[38] See AB 1890 (implementing Pub. Util. Code §§ 330(u), 335, 364(b)(1)); see also Green Book, p. 68.

IOUs, with an increase to 20% savings by Spring 2002.[39]

C. The Collapse of the Market

Under the CPUC's and Legislature's edicts, the Independent System Operator (ISO) would operate the state's transmission assets as a unified grid and would coordinate daily scheduling and dispatch of the electricity provided by market participants, while the Power Exchange (PX) would oversee the actual electricity market. These functions were separated to move away from the traditional vertically integrated utility structure and to prevent market manipulation.[40] In practice, separating the market clearinghouse from the load-serving function prevented the right hand from knowing what the left was doing. Under the new market structure, the IOUs were also prevented from entering into long-term contracts for electricity, which meant they had to buy their power on the spot market. This ultimately prevented the IOUs from hedging their electricity costs against market price fluctuations.

The dual-entity market structure functioned for a couple years, until the summer of 2000. Because the IOUs had divested approximately 40% of their power plants, and because no new large power plants were built in California in the late 1990s, California began to depend on imported electricity to meet its needs. A significant portion of imported power was from large hydroelectric facilities in the Pacific Northwest, which, at the end of 2000 was in the midst of a 100-year drought; California did not receive about 8,000 MW of power it was counting on. This shortfall meant that California's old fossil-fueled plants were being strained to make up the difference. And since late 1999, the ISO had issued "no touch" orders for the aging fossil plants, which meant their operators could not perform any maintenance. Record heatwaves in May and June 2000 caused the ISO to declare the first power shortage and led to a series of rolling blackouts in the San Francisco Bay Area. The ISO ordered these power cuts because electricity supplies were low and several generating plants were offline for maintenance.

These shortages were due partly to the aging generating fleet, which had not been maintained properly due to the ISO's orders and due to the fact that the IOUs had little incentive to fix up plants they would shortly have to sell. The shortages were

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[39] Green Book, p. 68.
[40] D.95-12-056, 64 CPUC 2d at p. 69–79.

also due to some plants being offline, which was the result legitimate equipment failure and also the result of market manipulation by some privately owned generators who wanted to drive up the price of electricity. Some independent power marketers also manipulated the amount of energy made available to the grid to create false grid congestion on major transmission corridors, which also drove up the price of electricity. And the IOUs themselves were able to manipulate the PX by submitting low demand forecasts for the following day, which left the PX scrambling when the un-forecasted demand hit the system the next day. It is worth noting that some of these schemes did not violate the market rules. Between the faulty market structure, legitimate power shortages, and market manipulation, electricity prices increased from $40/MWh in spring 1998 to $250/MWh[41] by December 2000.

The IOUs bought electricity at these exorbitant prices, but could not recover their costs from customers due to the retail rate cap. The Federal Energy Regulatory Commission (FERC) also denied the CPUC's request for a wholesale price rate cap, and instead imposed a "flexible" cap of $150/MWh; this was still more than a 300% increase over electricity prices the previous year. Because the IOUs were paying vastly more for electricity than they were getting from their customers' monthly bills, all three California IOUs hurtled toward bankruptcy—with PG&E actually declaring bankruptcy—and their credit ratings were downgraded to junk status. They couldn't buy power for their customers. Governor Gray Davis declared a State of Emergency by January 2001.

D. <u>The Legislative Response to the Energy Crisis</u>

After the Governor declared a State of Emergency, the Legislature, CPUC, and Governor's Office worked together to identify another entity in California that had the credit rating to buy the large amounts of electricity that the IOUs could not. They selected the California Department of Water Resources, which subsequently entered into long-term contracts backed by the State's credit. While this arrangement put an end to stratospheric energy prices, the contracts were executed when prices were high and California's electricity customers had to pay those costs.

The Legislature also passed a number of bills aimed at reestablishing order

[41] Some sources cite the record high prices at closer to $1400/MWh in late 2000.

in the electric market, which largely put the IOUs back in charge. The Legislature prohibited the sale of any IOU-owned power plants until 2006,[42] suspended Direct Access and put a 10% cap on the nonresidential DA market,[43] mandated long-term power purchase contracts in order to stabilize reliability and pricing,[44] expedited permitting of thermal power plants and adopted energy conservation initiatives,[45] returned the electric supply and demand forecasting function to the California Energy Commission,[46] and increased CPUC authority over power plants.[47] The Legislature also created the Resource Adequacy requirement by mandating that all LSEs maintain physical generation capacity sufficient to meet its load requirements[48] and authorized CCA formation.[49] CCAs, and the regulatory requirements that are now constraining them, arose as a direct result of the energy crisis.

IV. POWER AND MONEY: CCA RESOURCE ADEQUACY AND COST RESPONSIBILITY REQUIREMENTS

Increased CPUC influence over CCA operations is most significant in terms of Resource Adequacy and the Power Charge Indifference Adjustment (PCIA). The former is the requirement that all LSEs secure enough power to supply all of their customers on a high-electricity-use day. The latter is the amount CCA customers must pay to reimburse the IOU for the electricity it bought for those customers before they left IOU service for the CCA. Resource Adequacy is the lynchpin of the CPUC's one-year minimum freeze on new CCA operations, and will impose increased procurement requirements (which means more money out of pocket) in the future. The PCIA, which the CPUC is currently redesigning, has the potential to shift hundreds of millions of dollars onto CCA customers, which may well force existing CCAs out of business or prevent new CCAs from forming.

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[42] AB 6x (Dutra, Pescetti, Bowen).
[43] AB 1x (Keely, Migden).
[44] AB 57 (Wright).
[45] AB 970 (Ducheny).
[46] SB 1389 (Bowern). In the deregulated market, supply and demand were to have been provided by the competitive market instead of a statewide forecast. (See Green Book, p. 71.)
[47] SB 39xx (Burton, Speier).
[48] AB 380 (Nunes) (2005).
[49] AB 117 (Migden).

A. Resource Adequacy

The CPUC is charged with establishing Resource Adequacy (RA) requirements for all load-serving entities, which includes CCAs.[50] Resource Adequacy means that there is enough power available to serve the entire California grid in the coming year under high-electricity-demand scenarios, including demand spikes due to generator outages and transmission constraints; every LSE must demonstrate through monthly and annual filings that they have purchased capacity commitments of at least 115% of their peak load.[51] Capacity refers to the maximum output of electricity that a generator can produce under ideal conditions. Because all generators do not operate at maximum capacity 100% of the time, capacity is distinct from actual generation. Resource Adequacy focuses on capacity, instead of actual electric output, because the idea is that a certain amount of electricity has to be capable of being produced if necessary, not that the maximum level of energy be on the grid at all times.[52] This requirement—that there be more than enough power available to the grid at all times—arose as a direct result of the energy crisis.[53]

For purposes of resource adequacy requirements, CCAs are CPUC-jurisdictional LSEs.[54] Historically, the effect of CCA formation on the resource adequacy process has been minimal due to the small number of active CCAs. Since CCA formation began increasing rapidly in 2017, however, the effect on load allocation between IOUs and CCAs—and therefore the effect on resource adequacy commitments—has changed the procurement calculus faster than the CPUC has been

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[50] Pub. Util. Code §§ 380(a), (k).

[51] D.04-01-050, *Interim Opinion, Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development* (January 26, 2004), p. 22.

[52] There are three types of Resource Adequacy: system, flexible, and local. System RA refers to the amount of electricity needed to serve the entire CAISO grid under peak load conditions, plus a 15% planning reserve margin. Because not every region, county, or city in California has the same population density and electricity usage, LSEs must also meet specific local RA requirements. Local RA requirements are calculated by the CAISO and are allocated to each CPUC-jurisdictional LSE by the CPUC. Flexible RA capacity was developed in 2013, seven years after system and local RA were adopted in 2006. Flexible RA, or "flexible capacity need," is the amount of economically dispatched electricity needed by the CAISO to manage grid reliability during the greatest three-hour continuous ramp in each month.[52] In plain language, this means that flexible RA is necessary when electricity use on the statewide grid increases sharply and steadily over a three-hour period. As with local RA, the CAISO calculates its expected maximum flexible capacity needs for each month and the CPUC allocates that need by MW to each CPUC-jurisdictional LSE.

[53] D.04-10-035, *Interim Opinion Regarding Resource Adequacy* (November 4, 2004), p. 3.

[54] Pub. Util. Code § 380(a).

able to track. The most recent CPUC RA decision addresses the fact that CCAs have tended to launch or expand service at times of the year that do not correspond with the RA procurement cycle.[55] Because CCA formation causes a significant and automatic shift in load from the incumbent IOU to the CCA, the misalignment between CCA operational timelines and the RA planning process has left the IOUs with significant excess RA capacity for customers they no longer serve.[56] It also means the CCA must generally procure RA for its new customers on short notice, and that procurement is not factored into the CPUC's statewide annual RA plan. To stop the disconnect from getting worse, CPUC's Energy Division proposed that CCA participation in the year-ahead RA process be mandatory. The CPUC agreed.[57] CCAs must now submit load forecasts and year-ahead RA filings if they wish to serve load or expand their service territory in the following calendar year. This new requirement is what created the one-year implementation freeze imposed on new or expanding CCAs by Resolution E-4907.

In addition to the implementation holding period, the CPUC is currently considering how best to enact a multi-year local RA requirement for all LSEs.[58] The RA procurement cycle has always been one year, but recent resource shortages in specific locations and the rapid dispersal of RA responsibility among an increasing number of CCAs, prompted the CPUC to start looking at a three-to-five year RA cycle for local resources and the possibility of designating a central buyer.[59] The multi-year requirement will impose increased costs on LSEs because they will be required to buy capacity at the start of the cycle for each year of the cycle. The CPUC's Energy Division originally recommended LSEs be required to purchase 100% of their local RA requirement for Years 1 and 2 and 80% for Year 3; the CCAs, by contrast, proposed 90% for Year 1 and 25% for Years 2 and 3.[60] The CPUC directed 100% procurement in Year 1 and 95% in Year 2, and asked parties to make proposals for Year 3.[61] The CPUC also indicated that a central buyer for local RA is "the solution most likely to provide cost efficiency, market

[55] D.18-06-030, *Decision Adopting Local Capacity Obligations for 2019 and Refining the Resource Adequacy Program* (June 25, 2018), p. 17.
[56] *Ibid.*
[57] *Id.* at p. 16.
[58] See D.18-06-030, p. 28.
[59] *Id.* at pp. 24–25, 28–33.
[60] *Id.* at p. 29.
[61] *Id.* at pp. 29–30.

certainty, reliability, administrative efficiency, and customer protection."[62] While the CPUC asked for parties' proposals regarding the structure of the multi-year local RA program, and whether and how a central buyer should be established, it appears the CPUC heavily favors a central buyer of some kind.[63] If the CPUC continues down that path, the CCAs will lose a portion of the procurement autonomy they have defended so fiercely at the CPUC.

B. <u>Resolution E-4907: One-year Freeze on New CCA Operations</u>

Control over future purchasing decisions for local Resource Adequacy capacity is not the only limitation the CPUC has imposed on CCAs recently. With Resolution E-4907, the CPUC imposed an unprecedented restriction on CCA implementation: new or expanding CCAs must file their implementation plans by January 1 in order to serve load *starting in the following year*.[64] The purpose of this minimum one-year holding period is to align CCA operations with the CPUC's Resource Adequacy planning process.[65]

Before Resolution E-4907, CCAs were able to form and launch service on their own timeline. The only CPUC-related timing requirement was the 90-day period in which the CPUC had to certify receipt of the CCA's implementation plan, and the subsequent time (if any) necessary for the CPUC to provide the CCA with its determination of the costs CCA customers must pay to reimburse the IOU that used to serve them for any now-unnecessary power purchased on their behalf.[66] While the CCA would have to comply with CPUC-administered procurement requirements for resource adequacy and renewable energy, the CPUC's own view of its authority over CCA operations was always extremely limited.

The CPUC characterized the new CCA implementation timeline as "an informal process of review,"[67] but the substance of the Resolution shows an iron hand in a velvet glove. The CPUC did not change its longstanding conclusion that it lacks authority over actual CCA operations or procurement decisions, but instead justified its

[62] *Id.* at p. 32.
[63] *Id.* at pp. 32–33.
[64] Res. E-4907, p. 11.
[65] *Ibid.*
[66] Pub. Util. Code § 366.2(c)(7).
[67] Res. E-4907, p. 1.

abrupt directive as part of the statutory requirement that CCAs submit implementation plans to the CPUC, and as an extension of the 2005 decision that established the original filing practices.[68] The CPUC also cited to Section 366.2(c)(4), which requires CCA implementation plans to provide for universal access, reliability, equitable customer treatment, "and any requirements established by state law or by the commission concerning aggregated service."[69]

While the one-year minimum freeze may only be a function of the CPUC's limited purview over the submission of CCA implementation plans, the effect of that holding period is substantive. CCA comments on the proposed Resolution expressed concern with the apparent lack of process—the Draft Resolution issued without notice to or input from stakeholders—and the significant burden the waiting period would place on nascent CCAs.[70] The CPUC dismissed the due process concerns by stating that "[t]he changes in the CCA timeline made by this resolution are an exercise of authority the Commission has had since 2002. Section 366.2(c)(8) establishes the authority of the Commission to designate a CCA's start date with consideration of the impact on the [IOU's] annual procurement."[71] The CPUC created a limited exception to the new filing deadline in response to the outcry from CCAs: the filing deadline to serve load in 2019 was moved back two months to March 1, 2018, and a waiver process was created for CCAs that were able to reach an agreement with the IOU to resolve cost-shifting issues.[72] The CPUC's recent RA decision declined to extend this exception beyond 2018.[73]

C. <u>The Power Charge Indifference Adjustment</u>

The CPUC's resolution of the cost-allocation issue between IOU and CCA customers is the second thing that will have a significant impact on CCA operations in the future. The PCIA is part of the CPUC's Cost Responsibility Surcharge, which was implemented immediately after the energy crisis to ensure that customers that were on Direct Access service pre-crisis—the only customers allowed to get electricity from non-IOU providers post-crisis—paid their fair share of IOU costs incurred on their behalf

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[68] See *id.* at pp. 8–11.
[69] Res. E-4907, p. 10.
[70] *Id.* at pp. 15–17.
[71] *Id.* at p. 16.
[72] *Id.* at p. 17.
[73] D.18-06-030, p. 21.

before they became DA customers.[74] The PCIA specifically addresses the IOUs' above-market costs for the energy they procure, or power plants they built, on behalf of customers that subsequently leave for CCA or DA service. The bulk of the IOUs' PCIA-eligible portfolios are long-term contracts for renewable energy that were entered into when the renewables market in California was getting started; as a result, most of the contracts are significantly more expensive than the current market value for renewable energy.[75] This fact, combined with the rapidly increasing numbers of customers leaving utility service for CCAs, means that the IOUs are holding a significant amount of expensive power for which they have no customers—but the power still has to be paid for by the customers for whom the IOUs bought it.[76]

The current PCIA methodology does not accurately assign power costs between IOU and departed customers because it uses forecasts, administratively created benchmarks (placeholder prices), and other administrative cost adders,[77] instead of relying on actual contract costs, actual generation, and actual market prices for energy. The exact size and direction of the improper cost allocation is hotly disputed: the CCAs calculate an annual cost shift of $173 million from IOU customers to CCA customers[78]; the IOUs calculate an annual cost shift of $178 million in the other direction, from CCA customers to IOU customers.[79] The best way to change the methodology to eliminate the improper cost shifting is even more bitterly contested, and parties have proposed a range of revised benchmarks, annual true-ups, proposals to break up and reallocate the IOUs' energy contracts, and market-based solutions involving actual costs and revenues. The CPUC issued a Proposed Decision on August 1, 2018, which adopted a two-part solution. First, the market price benchmarks will be adjusted to more accurately reflect the market price of the IOUs' power contracts; a 2.2 cent/kWh cap and a 0.5 cent/kWh maximum

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[74] D.02-11-022, *Opinion, Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*, pp. 2–3. The current methodology used to calculate departing customer responsibility for IOU energy procurement costs was adopted in D.06-07-030 and revised in D.11-12-018.

[75] For example, in 2011 the price of solar energy was approximately $100/MW; in 2018, solar energy is between $30 and $50/MW. (See Joint IOU Testimony, R.17-06-026, pp. 1-10 (line 9)–1-11 (line 4).

[76] See Pub. Util. Code § 366.2

[77] Joint IOU Testimony, R.17-06-026, ch. 2, pp. 2-8 to 2-9. While the parties to the PCIA reform proceeding have different views on the specific flaws in the PCIA methodology and how best to address them, all parties agree the current methodology is not working.

[78] CalCCA Opening Brief, R.17-06-026, p. 25.

[79] Joint IOU Reply Testimony, R.17-06-026, ch. 1, pp. 1-6 (line24)–1-7 (line 3).

annual adjustment, coupled with an annual true-up process, will also be implemented.[80] In the second phase, the parties will continue to discuss longer-term market-based solutions to decreasing the IOUs' excess power portfolios and to fairly allocating the costs to customers.[81] On August 14, 2018, the Assigned Commissioner issued an Alternate Proposed Decision that, among other things, increased the rate collar to a 25% up/down range on either side of the previous year's PCIA rate.[82] The Alternate Proposed Decision also determined that CCAs are responsible to pay the costs of utility-owned generating plants that were built before 2002[83]; the Proposed Decision concluded that CCAs should *not* pay those costs.[84] The rate cap and limit on annual adjustments in the CPUC's tentative decision has granted a reprieve to departed load customers from bearing the full brunt of the IOUs' stranded power costs. The final decision, which may contain changes to the determinations in the Proposed Decision or Alternate Proposed Decision, and the outcome of Phase II of the proceeding will ultimately determine whether the PCIA will allocate hundreds of millions of additional dollars per year to CCA customers, which could eliminate CCA cost-competitiveness and drive customers back to the IOUs.[85]

V. THE GREEN BOOK: CPUC VIEWS ON EMERGING CUSTOMER CHOICE

The CPUC launched its California Customer Choice Project following a joint hearing with the California Energy Commission in May 2017. In May 2018, the CPUC issued the draft Green Book, which sets out the framework for the conversation between California's energy policy decision-makers and stakeholders about how to address the changing electricity market.[86] The Green Book addresses market changes other than CCA proliferation, such as the increase in rooftop solar and other behind-the-meter resources, but CCAs are a major focus. The fundamental questions posed in the Green Book concern ensuring grid reliability and resiliency, adequate consumer

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[80] Proposed Decision Modifying the Power Charge Indifference Adjustment Methodology (August 1, 2018), Ordering Paragraphs, pp. 128–131.
[81] Proposed Decision, R.17-06-026, Ordering Paragraph 10.
[82] Alternate Proposed Decision, R.17-06-026, Conclusion of Law Nos. 20 and 21.
[83] *Id.* at pp. 47–48.
[84] Proposed Decision, R.17-06-026, pp. 56–58.
[85] CalCCA estimates that CCA rates are on average 3% lower than the IOU rates.
[86] Green Book, p. iv.

protections given the new options, IOU ability to recover the costs of their power contracts and the costs of maintaining the transmission and distribution system that will continue to be used by CCAs and DA providers, and identifying who will be responsible (and financially able) for buying long-term power contracts, all while ensuring California's renewable energy goals are met.[87] The Green Book draws parallels between the market changes that led to the energy crisis and the changes resulting from CCA formation; the CCAs objected to this comparison.[88] Despite the CCAs' arguments to the contrary, the CPUC has yet to exorcise the spectre of the energy crisis and remains preoccupied with the implications of CCA proliferation for California's grid reliability.

On June 22, 2018, the CPUC and California Energy Commission held a joint *en banc* to discuss customer choice and the Green Book.[89] During the first panel on the level of choice Californians should have and how best to provide it, CPUC President Picker questioned CCA representatives on whether CCAs perform risk management at a level that the CPUC is looking for. President Picker focused on whether CCAs have a view on who should assume the responsibility of being the providers of last resort if the IOUs are relieved of that duty, and whether CCAs have a view on and a plan for the reopening of Direct Access for commercial and industrial customers—which form a significant rate base for any LSE—if the pending Senate Bill 237 passes.[90] President Picker said the answers made him "a little nervous" because it seemed to him that CCAs hadn't thought about it, and weren't accounting for the rapid legislative changes that can happen in the energy market, which indicated to him that CCAs aren't doing the kind of risk management that he wants to see. While President Picker was speaking in his personal capacity during the *en banc*, his concerns are mirrored in the CPUC's recent exercise of increased control over CCAs to ensure reliability and to prevent a second breakdown in the structure of the California energy market.

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[87] *Id.* at pp. 6–7.
[88] Comments of CalCCA on Draft Green Book, p. 2, available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/California%20Community%20Choice%20Association%20(CalCCA)_DraftGreenBookComments.pdf.
[89] Video available at: http://www.adminmonitor.com/ca/cpuc/en_banc/20180622/.
[90] SB 237 (Hertzberg) (2017–2018 Reg. Sess.). The bill was placed on the suspense file during its August 8, 2018, Assembly Appropriations Committee hearing.

VI. OTHER EXPANDED CPUC REGULATION OF CCAS

The CPUC has recently increased its oversight of CCAs in other areas, though these expanded requirements will not have as significant an impact on CCA operations as Resource Adequacy and cost responsibility.

A. Renewables Portfolio Standard Requirements

CCAs are required to file proposed RPS procurement plans to demonstrate their compliance with the renewable energy targets set forth in Senate Bill 350,[91] and the CPUC must issue a decision determining whether the plans comply with the statutory procurement requirements and CPUC rules. In 2016, CPUC determined that it was not necessary to require CCAs to file RPS solicitation documentation and cost quantification tables in their RPS plans, both of which the large IOUs must provide.[92] In the Ruling identifying issues and setting the schedule for the 2017 RPS procurement plan cycle, the Commission reversed this decision.[93] Because the rapid proliferation of CCAs is affecting the manner in which California's renewable energy targets are met and the manner in which the CPUC administers that process, the CPUC directed CCAs to include RPS solicitation and cost information in their procurement plans.[94]

In 2018, the CPUC increased CCA compliance requirements again. Now, in addition to project development status updates, potential compliance delays, and risk assessment information,[95] CCAs must also provide an assessment of their RPS portfolio supplies and demand, and explain how they intend to increase portfolio diversity to address issues of renewable integration, under-utilization of RPS-eligible generation, forecasted transportation electrification, and maximizing customer value; this discussion must be squared with the information previously submitted in CCAs' implementation

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[91] New CCAs must file their RPS plans upon registering with the CPUC or 90 days prior to delivering load, whichever occurs first. (D.17-12-007). Because CCAs are now subject to a minimum one-year freeze between registering and commencing service, RPS plans must be submitted along with the CCA's registration materials.

[92] D.16-12-044, *Decision Accepting Draft 2016 Renewables Portfolio Standard Procurement Plans* (December 15, 2016).

[93] Docket R.15-02-020, *Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2017 Renewables Portfolio Standard Procurement Plans, etc.* (May 26, 2017), pp. 6–7 ("2017 RPS Ruling").

[94] *Ibid*; see also Pub. Util. Code § 399.13(a)(5).

[95] 2017 RPS Ruling, p. 9, Table 1.

plans.[96] CCAs expanding their service territory must now provide quantitative data on how increased customer demand and load served will affect the CCA's RPS procurement and load forecasts, and an explanation of how the CCA plans to serve that load with existing or future procurement.[97] The 2018 RPS ruling also directs CCAs, for the first time, to identify their assumed minimum margin of procurement above the minimum level necessary to comply with the RPS program that will mitigate the risks of delayed or terminated renewable projects that are under contract to the CCA.[98]

This new information requirement will promote transparency and the ability of the CPUC to understand and forecast the amount and types of renewable energy resources that will serve California in the next 10 to 20 years.[99]

B. Integrated Resources Planning Requirements

The most recent iteration of the Integrated Resources Planning (IRP) process at the CPUC was instituted to address the new RPS requirements of SB 350.[100] SB 350 required *all* LSEs, not just the IOUs, to submit integrated resource plans to the CPUC[101]; integrated resource plans are intended to ensure LSEs have an optimized portfolio of energy resources that meets the policy goals of reliability, cost, and reducing GHG emissions.[102] As the CPUC considered how best to structure the new IRP framework to include CCA integrated resource plans, the CCAs urged the CPUC to take the same hands-off approach as with CCA implementation plans: certification that the IRP was submitted, but no substantive control over the procurement or planning contained therein.[103] The CPUC disagreed.[104] The CPUC concluded that its role "is to certify substantive compliance of the CCA's plan" to ensure consistency with the

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[96] Docket R.15-02-020, *Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2018 Renewables Portfolio Standard Procurement Plans* (June 21, 2018), p. 9 ("2018 RPS Ruling").
[97] *Ibid.*
[98] 2018 Ruling, p. 12
[99] 2018 RPS Ruling, pp. 6, 8.
[100] *Joint Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge*, R.16-02-007, p. 2.
[101] Rulemaking 16-02-007, p. 14.
[102] *Id.* at p. 13.
[103] D.18-02-018, pp. 23–24.
[104] *Id.* at p. 25 ("We maintain that our authority and responsibility over CCA planning is considerably broader than the CCAs and their representatives argue.").

requirements of SB 350.[105] If the CPUC finds that a CCA's integrated resource plan does not conform to the statutory requirements, the CPUC has the authority to order long-term procurement commitments by the CCA.[106]

C. Rulemaking on "Affordable" Utility Service

On July 12, 2018, the CPUC opened a Rulemaking to examine what constitutes "affordable" utility service, how the CPUC should measure it, and what changes must be made to ensure affordability.[107] The CPUC did not require CCA participation in this Rulemaking, but it encouraged them to become parties because CCAs may be affected by the outcome of the proceeding.[108]

VII. CONCLUSION

Despite the fact that CCAs are not answerable to the CPUC for the majority of their operations and decisionmaking, the CPUC has made it clear that it will exercise what authority it does have to the fullest extent in order to ensure reliability and to avoid a second energy crisis. The CPUC's recent edicts regarding implementation timelines, procurement requirements, and the costs that will ultimately be assigned to CCAs in the second phase of the PCIA proceeding will all have a marked effect on CCAs' daily operations and may impact their long-term viability.

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[105] *Id.* at pp. 26–27.
[106] *Id.* at p. 28.
[107] Rulemaking 18-07-006, pp. 10–12.
[108] *Id.* at pp. 15–16.