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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment U 39 E	Rulemaking 17-06-026 (filed June 29, 2017)

JOINT RESPONSE OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) AND PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) TO ASSIGNED COMMISSIONER'S AMENDED SCOPING MEMO AND RULING

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Dated: January 22, 2021

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Pursuant to the *Assigned Commissioner's Amended Scoping Memo and Ruling*, dated December 16, 2020 ("ACR"), Southern California Edison Company ("SCE"), San Diego Gas & Electric Company ("SDG&E"), and Pacific Gas and Electric Company ("PG&E") (collectively, the "Joint Utilities"),[1] respectfully submit responses to the ACR.

I. THE POWER CHARGE INDIFFERENCE ADJUSTMENT (PCIA) CAP

1. Should the Commission remove or raise the PCIA cap? Please provide rationale for your answer.

When considering this issue, the Commission must ask itself a fundamental question: Should a relatively affluent and growing majority of customers continue to be subsidized by a relatively less-affluent and shrinking minority of customers, in direct contravention of unambiguous statutory prohibitions as well as basic principles of equity and economic justice? The Joint Utilities respectfully submit that the answer to that question is obviously "no;" yet failing to eliminate the Power Charge Indifference Adjustment ("PCIA") rate "cap" mechanism now would continue to perpetuate that unjust outcome. The PCIA cap effectively functions as a loan from bundled service customers to departing load customers, the latter group of which the Commission has estimated will soon constitute ***up to 85%*** of total CPUC-jurisdictional customer load.[2] Moreover, even the purported intended purpose of the cap – namely, to provide PCIA rate stability and certainty to departing load customers -- is no longer valid

[1] Pursuant to Rule 1.8(d), counsel for PG&E affirms that SCE and PG&E have authorized PG&E to file this Response on behalf of the Joint Utilities.

[2] *See* CPUC Staff White Paper, *Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework (*May 2017) at p. 3.

(if it ever was). The existence of the cap (in conjunction with the required "trigger" mechanism) exacerbates PCIA rate instability; it does not mitigate against it. Indeed, the ACR notes that all three Investor-Owned Utilities ("IOUs") have triggered due to the PCIA cap.[3] Setting aside that it is not the Commission's obligation or even purview "to protect the economic viability of" Community Choice Aggregators ("CCAs") – a fact that the Commission has recently made explicit[4] – given that the cap is now acting contrary to the very pro-CCA purpose it was designed to further, the Joint Utilities expect even the CCAs to support its termination. Finally, as discussed in detail below, the PCIA cap is not "fixable," as the entire concept supporting its creation and continued existence is fundamentally flawed and legally unsupportable.

The Commission should remove the PCIA cap to address statutory violations and significant policy concerns arising from application of the arbitrary 0.5 cents/kilowatt-hour ("kWh") annual cap on increases to departing load customer PCIA rates. As discussed in more detail below, application of the cap results in significant under-collection from departing load customers of the Portfolio Allocation Balancing Account ("PABA") revenue requirement by the IOUs. Thus, retention of the cap creates a material risk of continual cost-shift to bundled service customers – an outcome that violates the Commission's statutory obligation under Public Utilities Code §365.2 to prevent "*any* cost increases" to remaining bundled service customers resulting from load departure,[5] as well as its duty under Section 451 to ensure reasonable rates for bundled service customers.

In addition, application of the PCIA cap fails to effectively mitigate rate volatility for departing load customers – a fact noted by the ACR: "There is a concern over increasing undercollections in PABA of each investor-owned utility. One of the factors contributing to growing PCIA undercollections in PABA is the PCIA cap. … If the cap continues to be reached, the situation will be exacerbated by undercollections from previous years …. . The continuous increase in undercollections requires reconsideration of the PCIA cap."[6] This discussion illustrates that the primary rationale offered

[3] *See* ACR at pp. 4-5.

[4] *See* D.19-08-014, p. 12.

[5] Pub. Util. Code §365.2 (emphasis added); *see also* §§ 366.2 and 366.3. All statutory references herein are to the Public Utilities Code unless otherwise noted.

[6] ACR at pp. 4-5 (internal citation omitted).

to justify adoption of the cap requirement – namely, that the PCIA rate cap would provide rate stability and predictability for departing load customers[7] – is now moot.

Finally, the cap conflicts with Commission policy and is contrary to the public interest. The cap is not sustainable in an environment of increasing load departure. It unreasonably shifts the responsibility of managing CCA and Direct Access ("DA") providers' market risk to remaining bundled service customers and contravenes the Rate Design Principles adopted by the Commission in Decision ("D.").15-07-001. In doing so, it obscures the true cost of being served by a CCA or DA provider at the expense of bundled service customers, thereby interfering with customers' ability to make efficient economic choices. The fact that interest is earned on the resulting PCIA undercollection amount does not overcome the legal and equitable flaws with the PCIA cap.

Accordingly, the Joint Utilities respectfully request that the Commission eliminate the PCIA cap. Rather than artificially lowering PCIA rates, the full amount of the PCIA rates calculated in accordance with the requirements of D.18-10-019 and D.19-10-001 and assigned to each customer vintage should be billed to departing load customers. That result is not only logical and equitable, but consistent with how bundled service customers pay the full amount of the PCIA rate through generation rates. As discussed below, application of the rate cap over the last year caused significant under-collections from departing load customers for each of the Joint Utilities and directly led to the filing of trigger applications. Analysis of actual and forecast data by each of the Joint Utilities demonstrates that the rate cap will not operate as intended and will in fact *increase* the likelihood of cost-shift and PCIA rate volatility. Accordingly, the PCIA cap requirement must now be eliminated.

The PCIA rate is intended to ensure equitable allocation of above-market portfolio costs between bundled service customers and customers who depart bundled service to be served by a non-IOU load-serving entity. In the Phase 1 Decision, the Commission adopted, among other things, a 0.5 cents/kWh cap on annual increases to the PCIA rate. The Commission concluded that the PCIA cap would "provide a degree of the rate stability and predictability sought by parties representing departing load interests,"[8] and further that "[s]uch a cap should reduce extreme PCIA price spikes, and bill impacts, but not enable a continual state of significant undercollection."[9] The primary rationale offered by the Commission to support adoption of the rate cap was the desire to provide departing load customer rate

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[7] *See* D.18-10-019, p. 3.
[8] D.18-10-019, p. 3.
[9] D.18-10-019, p. 85.

stability and predictability.[10] The Commission noted that significant annual swings in energy prices cause significant annual swings in the PCIA rate, and that "[community choice aggregators ("CCA")] indicated in comments that such swings make their resource planning extremely challenging . . ."[11] Thus, the cap was intended to protect departing load customers from the volatility that is inherent in the energy markets by transferring that risk to bundled service customers. In adopting the rate cap requirement, the Commission assumed that any under-collection of the PCIA would be short-term. It noted parties' expectation that application of the cap would result in a "temporary" under-collection,[12] and conveyed its intent that the cap "not enable a continual state of undercollection."[13] However, implementation of the cap requirement by the Joint Utilities demonstrates that the opposite is true.

PG&E's 2020 PCIA Undercollection Balancing Account ("PUBA") Trigger Application ("A.") 20-09-014 illustrates that the PCIA cap and trigger mechanism can result in significant PCIA volatility. Over 2020, PG&E's undercollected PUBA balance was forecast to grow to approximately $250 million by the end of 2020.[14] PG&E's PUBA Trigger Application demonstrated the challenges of timely refunding bundled service customers for subsidizing artificially low PCIA rates. Amortization of the 2020 undercollected balances within the calendar year had the potential to increase departing load PCIA rates by 222 percent and create significant rate shock.[15]

Capped PCIA rates can frustrate rate stability and predictability on an ongoing basis. In PG&E's 2021 ERRA Forecast proceeding, CCA parties raised concern that PG&E's projected 2021 PUBA balance would likely cause a 2021 trigger application.[16] In D.20-12-038, the Commission disposed of PG&E's 2020 and forecast 2021 PUBA balances through a rate adder, proposed as a component of a Settlement Agreement and intended to reduce volatility. The Commission adopted the solution as

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[10] D.18-10-019, p. 3.

[11] D.18-10-019, p. 86.

[12] D.18-10-019, p. 85 (citing testimony submitted by the Coalition for Utility Employees, as well as the testimony of the Joint Utilities).

[13] D.18-10-019, p. 85.

[14] PG&E's PUBA balance as of December 2020 close is $244.5 million. *See* PG&E's December 2020 ERRA Activity Report at p.5, served to the R. 17-06-026 service list on January 20, 2021.

[15] Specifically, a one-month amortization would increase departing load PCIA rates by approximately 222 percent and decrease bundled service generation rates by approximately 75 percent. *See* A.20-09-014 (Declaration of Benjamin Kolnowski, p. 7). While longer amortization periods can mitigate rate shock, longer periods can unjustly prolong subsidies, conflicting with bundled service customer indifference.

[16] PG&E's PUBA Trigger Application was consolidated with PG&E's 2021 ERRA Forecast (A.20-07-002).

reasonable "in light of the extremely large 2020 PUBA balance and projected 2021 PCIA amount above the cap."[17]

As shown in SCE's 2020 PCIA Trigger Application (A.20-10-007), full recovery of the forecast 2020 year-end PCIA Trigger balance would have – *alone* – resulted in 2021 PCIA rate increases to departing load customers of up to almost 40 percent for some vintages.

Proposed Illustrative 2020 PUBA Sur-Charge Rates by Vintage

Rate Group	PCIA 2011 Vintage	PCIA 2012 Vintage	PCIA 2013 Vintage	PCIA 2014 Vintage	PCIA 2015 Vintage	PCIA 2016 Vintage	PCIA 2017 Vintage	PCIA 2018 Vintage	PCIA 2019 Vintage
Domestic	0.00058	0.00101	0.00048	0.00266	0.00264	0.00890	0.00440	0.00590	0.00298
TOU-GS-1	0.00045	0.00078	0.00037	0.00206	0.00204	0.00688	0.00340	0.00456	0.00230
TC-1	0.00041	0.00072	0.00034	0.00188	0.00187	0.00629	0.00311	0.00418	0.00211
TOU-GS-2	0.00046	0.00080	0.00038	0.00209	0.00207	0.00699	0.00345	0.00463	0.00234
TOU-GS-3	0.00043	0.00076	0.00036	0.00199	0.00197	0.00664	0.00328	0.00440	0.00222
TOU-8-Sec	0.00042	0.00074	0.00035	0.00194	0.00193	0.00649	0.00321	0.00430	0.00217
TOU-8-Pri	0.00041	0.00072	0.00034	0.00189	0.00188	0.00632	0.00312	0.00420	0.00212
TOU-8-Sub	0.00039	0.00068	0.00032	0.00178	0.00177	0.00596	0.00294	0.00395	0.00200
TOU-PA-2	0.00042	0.00074	0.00035	0.00194	0.00193	0.00650	0.00321	0.00431	0.00218
TOU-PA-3	0.00041	0.00071	0.00034	0.00187	0.00186	0.00626	0.00310	0.00415	0.00210
St. Lighting	0.00039	0.00067	0.00032	0.00177	0.00176	0.00593	0.00293	0.00393	0.00199
Standby - Sec	0.00041	0.00072	0.00034	0.00190	0.00189	0.00636	0.00314	0.00421	0.00213
Standby - Pri	0.00041	0.00072	0.00034	0.00189	0.00188	0.00632	0.00312	0.00419	0.00212
Standby - Sub	0.00039	0.00068	0.00032	0.00178	0.00176	0.00594	0.00294	0.00394	0.00199
Average[1]	**0.00041**	**0.00073**	**0.00035**	**0.00223**	**0.00181**	**0.00726**	**0.00342**	**0.00516**	**0.00259**
Current Rate (6/1/2020) w/ 2021 Bdets	**0.01574**	**0.01652**	**0.01661**	**0.01937**	**0.01526**	**0.01827**	**0.01747**	**0.01966**	**0.01949**
% Increase Over Current	***2.60%***	***4.43%***	***2.09%***	***11.49%***	***11.85%***	***39.73%***	***19.56%***	***26.24%***	***13.26%***

[1]SCE applied forecast 2021 vintage billing determinants ("Bdets") to these calculations.

This level of rate increase from the PCIA rate cap alone leads to rate shock and rate volatility for departing load customers, which is exactly what the PCIA rate cap was presumably adopted to prevent.

Similarly, as demonstrated in SDG&E's 2020 PCIA undercollection balancing account ("CAPBA") trigger application (A.20-07-009), the PCIA rate cap and trigger mechanism creates significant rate volatility for departing load customers as the result of two primary factors. First, the trigger mechanism is structured to charge departing load customers for the revenue shortfall (*e.g.*, the undercollection) over fewer months than if a rate cap did not exist. Once the trigger is met, SDG&E must propose a revised PCIA rate that will bring the projected CAPBA account balance below 7% and maintain the balance below that level until January 1 of the following year, when the PCIA rate adopted

[17] D.20-12-038, p 18.

in SDG&E's ERRA forecast proceeding will take effect.[18] In other words, SDG&E must recover the undercollection from departed load customers over the remaining months of the year, which could be anywhere from one to six months depending on when the trigger threshold is met.

Second, the characteristics of departing load in SDG&E's distribution service territory is unique among the three IOUs in that it is (currently) almost entirely DA. While a significant level of CCA load departure in SDG&E's distribution service territory is anticipated in the near future, SDG&E's departing load sales (*i.e.*, billing determinants) to date are almost entirely non-residential and are weighted more heavily toward the Medium/Large Commercial and Industrial ("M/L C&I") class. The combination of departing load sales skewed toward one customer class and an authorized revenue allocation methodology approved for PCIA rates of generation revenue allocation factors, which was developed based on SDG&E's bundled customer load, results in PCIA rates from the CAPBA trigger that create signification rate shock for those departing load customer classes with minimal sales (*e.g.*, residential, agriculture and streetlighting). While anticipated load departure over the next two years could help to minimize rate shock from CAPBA triggers for vintage 2020-2022, departed load sales in the earlier vintages such as 2009-2012, 2014 and 2015, which are entirely made up of DA customers, will continue to be skewed.

An additional concern regarding the cap and SDG&E's CAPBA trigger relates to the timing of load departure in 2021. SDG&E anticipates that almost 15% of its load will depart *mid-year* (departure plans vary for DA and CCAs customers), leaving remaining bundled service customers responsible for financing the PCIA cap resulting from SDG&E's 2021 ERRA Forecast Application. Maintaining customer indifference as half a million customers depart bundled service throughout multiple months of 2021 will be challenging enough; a scenario in which customers finance the 2021 resulting PCIA cap for part of the year through SDG&E's commodity rates until they depart bundled service, and then begin paying [capped] PCIA rates is exponentially more difficult. Tracking and accounting for customer departure of that magnitude at an individual customer level is impossible, which makes maintaining customer indifference if/when SDG&E files its 2021 CAPBA Trigger application impossible.

Section 365.2 requires the Commission to protect bundled service customers from "*any* cost increases" due to load departure.[19] The California Supreme Court has observed that "[i]n construing a

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[18] D.18-10-019, at Ordering Paragraph ("OP") 10(d).

[19] Section 365.2 (emphasis added); *see also* Sections 366.2 and 366.3.

statute to ascertain the intent of the Legislature, first and foremost, the Commission should give effect to the plain meaning of the language in the statute."[20] In this case, the language in the statute could not be more clear: "*Any*" cost increase to bundled service customers due to load departure is a violation of the Commission's statutory obligation to ensure cost indifference. The PCIA is a zero-sum game: Every dollar that should be but is not paid by departing load customers is paid by bundled service customers.

Nevertheless, the Phase 1 Decision offers a more nuanced interpretation of the requirements of Section 365.2. It suggests that the statutory prohibition on imposition of "any" cost increase on bundled service customers due to load departure does not apply to a temporary under-collection of the PCIA rate from departing load customers so long as the under-collection is repaid with interest.[21] While this interpretation would as a factual matter permit an outcome where bundled service customers experience a cost increase due to load departure, which appears on its face to violate the plain language of the statute, the more pertinent issue is that the Commission's assumption that the cap would result in only a temporary under-collection is now known to be incorrect.

In approving the PCIA rate cap in the Phase 1 Decision, the Commission concluded that the cap would not enable a continual state of significant undercollection.[22] As discussed above, this finding is erroneous. Significant under-collection of the PCIA is likely to be a recurring circumstance for at least some of the IOUs. Moreover, shifting cost to an ever-dwindling pool of bundled service customers will result in even greater cost-shift as time goes on. For example, in 2020 PG&E's bundled service customers (40 percent of load) will have financed approximately $250 million in reduced PCIA rates for a departing load customer majority (60 percent of load).[23] This translates to a bundled service customer paying an additional $1.50 for every dollar avoided by a departing load customer on an electric bill through application of the PCIA rate cap. The inequity of this circumstance, as well as its unsustainability as load departure continues to increase, is abundantly clear.

Even more problematic, the impact of this cost-shift in many cases is being felt by those customers who are least able to afford it. For example, the median household income in counties in

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20 *See Collection Bureau of San Jose v. Rumsey* (2000) 24 Cal.4th 301, 310.

21 D.18-10-019, p. 87.

22 D.18-10-019, p. 85.

23 Based on 2021 load forecast filed in A.20-07-002, July Supplemental Testimony, Table 2-3, bundled load is approximately 40% of PG&E system sales and departed load is approximately 60%. This calculation reflects the system average, not the residential customer-specific, impact

PG&E's distribution service territory without a CCA is approximately ***40 percent lower*** than counties with CCAs.[24] Thus, a PG&E bundled service customer in Bakersfield or Fresno will pay a relatively higher electric bill than a CCA customer in Marin or Sonoma in order to enable the CCA customer to enjoy the benefit of a capped PCIA rate. Further, approximately 70 percent of PG&E's residential disadvantaged communities accounts are located in the Central Valley – underscoring the injustice of continuing to require bundled service customers to finance the under-collection resulting from the cap.

Put simply, the continual PCIA undercollection that results from the PCIA rate cap, violates the Commission's obligation under Sections 365.2, 366.2 and 366.3 to protect bundled service customers from ***any*** cost-shift caused by load departure. In addition, more broadly, requiring bundled service customers to continually pay higher rates in order to provide a capped PCIA rate to CCA and DA customers results in a failure of the Commission to discharge a core obligation under the Public Utilities Code. The Commission has no duty to guarantee the economic success of CCAs or DA providers; indeed, the Commission has elsewhere acknowledged that "nothing in the statute requires the Commission to protect the economic viability of CCAs or ensure they remain viable concerns."[25] Likewise, the Commission does not have jurisdiction over the generation rates charged to departing load customers and plays no role in determining whether those rates are reasonable. The Commission does, however, have a statutory obligation to ensure that bundled service customers' rates are reasonable (Section 451), and to prevent *any* costs from being shifted to bundled service customers due to departure of other customers to be served by a CCA or DA provider (Sections 365.2, 366.2, and 366.3). No fix other than eliminating the PCIA rate cap reasonably addresses these legal and equity concerns. Accordingly, to fulfill its statutory obligations, the Commission should now eliminate the PCIA rate cap in its entirety.

The PCIA rate cap is also incompatible with customer choice. As customers continue to depart utility bundled service, the concept of a rate cap financed by a minority sub-set of bundled service customers to benefit the majority of customers served by a CCA/DA provider becomes even less

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[24] A population-weighted average of median household income in counties without a CCA are approximately 40% lower than counties with CCAs (based on data from the California Association of Counties https://www.counties.org/data-and-research). Moreover, bundled service customers in the Central Valley region have relatively higher electric bills (due in part to higher cooling usage). Finally, bundled customers in the Central Valley, which make up about 20% of PG&E's electric accounts, also have a higher relative level of disadvantaged communities (the area includes about 70% of DAC accounts).

[25] D.19-08-014, p. 14.

tenable. The Phase 1 Decision was issued in an environment that predated significant load departures from the three IOUs. But since 2018, millions of additional customers have departed bundled utility procurement service for alternative service providers (the vast majority to CCAs). Indeed, the Commission itself has estimated that up to 85 percent of load will be served by non-IOU LSEs by the mid-2020s.[26] Given the current and forecasted levels of load departure, the notion that bundled service customers can or should continue to finance the under-collection resulting from capped PCIA rates is unreasonable.[27]

Moreover, customers with cost responsibilities for PCIA must bear the risk of market volatility. The desire to protect CCA and DA providers' customers from rate spikes caused by significant fluctuations in energy market prices was the primary rationale offered in the Phase 1 Decision for capping the PCIA rate.[28] However, price volatility is an intrinsic, unavoidable aspect of energy markets. Indeed, the recognition that market prices fluctuate is central to the market price benchmark value-based PCIA mechanism that most parties advocated for in lieu of an allocation mechanism, and which the Commission adopted in D.18-10-019. Given their support for the market value-based PCIA mechanism it is now incumbent upon CCA and DA providers to manage this inherent volatility without shifting risk and cost away from their customers and onto remaining bundled service customers. The ability to manage market risk is a basic requirement for any market participant. As discussed, the Commission's legal duty is to protect bundled service customers; it has no obligation to ensure the viability of CCA or DA providers, and no jurisdiction to set departing customer generation rates or to ensure that CCA and DA providers are properly hedged against market price risks. It is also important to remember that the PCIA is generally negatively correlated with market prices; thus, when the PCIA is

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[26] CPUC Staff White Paper, *Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework* (May 2017) at p. 3.

[27] Indeed, the relationship between a decreasing pool of bundled service customers and the increasing subsidy that any deficiency in the PCIA mechanism will cause – and the cap is a prime example of such a deficiency– is not linear. As explained by the Joint Utilities in Phase 1 of this proceeding, that relationship is instead exponential. For example, at 20% penetration of departing load and assuming that the PCIA is set only 20% below where it should be, the resulting rate increase to the 80% of remaining bundled service customers is a relatively modest – albeit, still unlawful – 0.35 cents/kWh. But at 80% penetration of departing load, that same 20% PCIA rate deficiency would lead to a 5.58 cents/kWh rate increase for the 20% of remaining bundled service customers (*i.e.*, a ***73% increase*** in their generation rates). *See* Joint Utilities' December 5, 2017 Workshop Presentation #1B in Phase I at Slide 19.

[28] *See, e.g.*, D.18-10-019, p. 86 (affirming that the PCIA cap will protect departing load customers from volatility in the PCIA, caused by "significant annual swings in energy prices leading to significant annual swings in the PCIA rate.").

relatively high, energy market prices are generally relatively low. It is also reasonable from a policy perspective to expect CCA and DA providers to develop sustainable methods for coping with the risks that are an integral aspect of the energy markets and the market value-based PCIA mechanism, which the CCA and DA providers overwhelming supported over the alternative of *pro rata* allocations of IOUs' PCIA-eligible resources.

Requiring bundled service customers to protect departing load customers from market risk is even more problematic when one considers that bundled service customers are exposed to the exact same market risk. The PCIA is paid by both departing load and bundled service customers – the only distinction is that for bundled service customers, the PCIA rate is embedded in their commodity rates (and the Commission *requires* the IOUs to be properly hedged against market risks).[29] Generation costs for bundled service customers are approved through the ERRA proceeding and are typically passed on to bundled service customers on an annual (or more frequent) basis irrespective of their volatility.[30] Thus, the rate cap offers asymmetrical protection. It offers departing load customers protection from price volatility that is not afforded to bundled service customers. This inconsistency between bundled service customers and departing load customers in the treatment of analogous generation costs is not reasonable or justifiable and is a violation of the Commission's statutory obligations under Sections 451, 366.2, 366.3 and 365.2 to ensure the reasonableness of bundled service customers' rates.

2. If you think the PCIA cap should be raised, explain by how much it should be raised and provide rationale for your answer.

N/A. The cap should be eliminated. See answer to Question 1, above.

3. Would removal of the PCIA cap have an impact on Community Choice Aggregators' or Electric Service Providers' overall financial viability? Please provide a financial analysis to demonstrate the impact.

As discussed in the Joint Utilities' response to Question 1, that question is legally irrelevant, as recently acknowledged by the Commission. Moreover, Electric Service Providers ("ESPs") generally serve large, sophisticated industrial and commercial DA customers. The concept of the Commission

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[29] *See* Section 454.5 (d)(4)-(5) (requiring IOU procurement plans to moderate price risk and provide an appropriate balancing of price level and price stability). Beginning with D. 02-10-062, the Commission required IOU bundled procurement plans to provide detailed descriptions of processes to hedge price risk. See D 02-10-062 at p. 30.

[30] Exhibit IOU-3, p. 5-11, lines 16-23. It should be noted that it the Commission's statutory obligation to allow the IOUs to recover their procurement costs from bundled service customers in a timely fashion. *See* P.U.C. Section 454.5(d)(3).

saddling remaining bundled service customers with rate increases in order to subsidize such customers to ensure the "overall financial viability" of the largely unregulated ESPs who choose to serve them defies logic and reason. Second, regarding CCAs, CalCCA has claimed that "[m]any CCAs have rate stabilization funds that can be used to buffer rates in the event of a sudden spike in wholesale energy markets."[31] CalCCA has further suggested that these rate stabilization funds allow CCAs to remain competitive in the event of "increases to non-bypassable charges, including the PCIA in particular" and that "it would likely take several years of upward market conditions to exhaust any such reserve or rate stabilization fund."[32]

4. What principles or other factors should inform the Commission's consideration of any modifications to the cap and trigger process?

As explained above, the Commission's paramount and overriding concern must be upholding statutory prohibition against customer cost-shifting as a result of departing load. That is the only "principle" that is legally relevant. In addition, all the other "factors" that should inform the Commission's decision regarding the cap militate in favor of its elimination, not modification.

5. The investor-owned utilities must file expedited applications for approval in 60 days from the filing date when the trigger balance reaches 7% of forecast PCIA revenues.

a. Should the Commission revisit the 60-day timeframe?

b. Are there other modifications to the PCIA trigger mechanism that the Commission should consider, such as revisiting the PCIA trigger amount currently set to 10 percent of forecast PCIA revenues? If so, explain in detail the proposed modification and provide rationale for your answer.

N/A. The cap should be eliminated. Moreover, modifying the cap-and-trigger mechanism to put in place a ***higher*** threshold before triggering would exacerbate all of the deleterious effects of the cap the Joint Utilities describe in the response to Question 1, including increased cost shifts to bundled service customers and increased PCIA rate volatility for departing load customers.

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31 *California Community Choice Association (CalCCA) Comments on the California Consumer Choice Project Workshop*, p. 5, *available at* http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CA%20Community%20Choice%20Aggregators.pdf.

32 Phase 1 Exhibit IOU-100, pp. 26:19 to 27:5. Note that Sonoma Clean Power represented in 2017 that it expected to have over $40 million in its reserve accounts, while MCE reported reserves of $50 million. *See* Phase 1 Exhibit IOU-120.

6. **Should the PCIA cap be applied to the prior year's forecast PCIA rate, or each prior year's final PCIA rate that includes the true-up recorded actuals for energy and the Commission-issued final Resource Adequacy (RA) and Renewables Portfolio Standard (RPS) adders? Provide rationale for your answer.**

N/A. The cap should be eliminated. See answer to Question 1, above. If the Commission decides to retain the cap, however, it should apply to the "final" PCIA rate – which is the actual PCIA rate for the year and more representative of the actual above-market value that the PCIA seeks to recover. As shown in the table below, the forecast market price benchmarks (MPBs) issued by the Commission have inflated the market value of the IOUs' PABA-eligible resources, resulting in year-end true-ups in the hundreds of millions of dollars that must be recovered via the following year's PCIA rates.

	2019			
MPB	**Forecast Adder**	**Final Adder**	**% Change**	**Comments**
Energy Index	$41.97/MWh	N/A* (use actuals)	N/A*	*$30.50 (SCE's actual PABA portfolio weighted average DAM revenue); -27.33%
RPS Adder	$18/MWh	$16.44/MWh	-8.67%	
RA Adders				
System	$37.08/kW-yr	$33.24/kW-yr	-10.36%	
Local	$37.08/kW-yr	$44.64/kW-yr	20.39%	
Flex	N/A	$33.36/kW-yr	N/A	
	2020			
MPB	**Forecast Adder**	**Final Adder**	**% Change**	**Comments**
Energy Index**	$34.54/MWh	N/A (use actuals)	N/A	*$31.88 (SCE's actual PABA portfolio weighted average DAM revenue); -7.70% (Jan-Sept; includes impacts of Aug heatwave) *$21.67 (SCE's actual PABA portfolio weighted average DAM revenue); -37.26% (Jan-July; prior to Aug heatwave)
RPS Adder	$17.35/MWh	$15.10/MWh	-12.97%	
RA Adders				
System	$55.08/kW-yr	$62.40/kW-yr	3.29%	
Local	$51.60/kW-yr	$58.08/kW-yr	12.56%	
Flex	$52.92/kW-yr	$55.80/kW-yr	5.55%	

**The 2021 Forecast Energy Index was set at $40.59/MWh, which will likey result in a significant undercollection in the PABA in 2021 as the result of an inflated market value and artifically low PCIA rate.

For example, in 2019, SCE's PCIA true-up related to market value resulted in an undercollection of $519 million.[33] In 2020, the PCIA true-up undercollection related to market value resulted in an undercollection of $284 million.[34] It is inappropriate to apply an arbitrary rate cap (to only certain customers) to an already artificially low PCIA rate (because one of more of the MPBs was set too high on a forecast). Doing so will always result in large undercollections in the PABA and PCIA Undercollection Balancing Accounts ("PUBA" for SCE & PG&E or "CAPBA" for SDG&E) – which then have to be recovered in the following year. Using the "final" PCIA rate will not completely

[33] A.19-06-002, Exhibit SCE-6C, Table X-50, Lines 3, 5 and 7.

[34] A.20-07-004. Exhibit SCE-4C, Table X-54, Line 13.

address this problem, but at a minimum it would apply the arbitrary rate cap (to the extent it is inappropriately retained) to a less artificially-low PCIA rate. This would minimize the PCIA rate cap impact to bundled service customers and should minimize PCIA rate volatility given that more of the current year's undercollection could be recovered from the appropriate customers in the following year.

7. Should the Commission adopt a methodology for crediting or charging customers who depart from the utility service during an amortization period and who are responsible for a balance in the PCIA Undercollection Balancing Accounts, the Energy Resource Recovery Account (ERRA), or any other bundled generation account? Explain in detail what methodology you recommend and provide rationale for your answer.

Attempting to recover or refund amounts owed from or to individual customers who transfer service would be administratively complex and costly. Moreover, this issue only impacts a small percentage of departing load customers for a single year when they transition from bundled service to departing load. Currently implemented solutions, such as PG&E's, that attempt to recover or refund ERRA balances left behind by recent departing load customers, such as transferring the ERRA balance to the last vintage subaccount of PABA, results in a recovery from or refund to approximately the right group of customers.[35] The imprecision results from differences in the timing of the departures and the fact that customer vintages are set on a split-year basis rather than a fiscal year basis.

As a threshold matter, with the exception of the bundled financing portion of the PUBA/CAPBA, the majority of the balances in the PUBA/CAPBA, by vintage, are the responsibility of customers who have already departed bundled service whereas balances in the PABA subaccounts are always the responsibility of both bundled and departing load, and the ERRA balance has the potential to be shared with recent departing load customers. To address going-forward customer departures from bundled service, the Commission should continue to implement the recovery or the return of the balances in the ERRA and bundled financing portion of the PUBA/CAPBA consistent with the ratemaking adopted in SCE's 2020 and 2021 ERRA Forecast proceedings.[36] Specifically, the year-end balance in the ERRA should be transferred to the corresponding subaccount of the PABA (e.g., the 2020 year-end balance in the ERRA is transferred to the 2020 subaccount of the PABA) to be recovered from or returned to then-

35 *See* D. 20-12-038 at Conclusion of Law 7 (adopting PG&E's proposal to return the 2019 overcollected ERRA balance).

36 *See* D.20-12-035, pp. 25, 43-44 and Exhibit 4C in A.20-07-004, pp. 103-104. *See also* D.20-01-022, pp. 20-21.

bundled service customers, and, similarly, the year-end balance in the bundled financing portion of the PUBA/CAPBA should be transferred to the corresponding subaccount of the PABA (e.g., the 2020 year-end balance in the 2020 bundled financing PUBA/CAPBA subaccount is transferred to the 2020 subaccount of the PABA) to be returned to bundled and recent departing load customers. This ratemaking approach reasonably and simply addresses the recovery or return of previous year balances for scenarios in which customers subsequently depart bundled utility service during the amortization period. This approach also most effectively manages customer indifference so certain customer groups are not stranded with costs incur on behalf of customers departing bundled service or returning to bundled service.

II. IMPROVING PCIA AND ERRA ALIGNMENT

1. How should the Commission modify the deadlines and requirements of ERRA and PCIA-related submittals and reports in order to increase time for parties to review PCIA data while facilitating an ERRA implementation on January 1 of each year? Explain in detail the proposed modification and provide rationale for your answer.

The ERRA Forecast proceeding, in which PCIA rates are set for the upcoming calendar year, has undergone several significant changes in recent years. As a result of D.18-10-019 and D.19-10-001, the proceeding now includes the "true-up" of the *current* year's PCIA rates as part of the November Update.[37] Additionally, the IOUs have been ordered to provide additional underlying volumetric data related to current year PABA activity in the ERRA Forecast proceedings.[38] Given that the latter requirement was just adopted, the IOUs recommend no further changes to reporting processes until there is some experience with the new requirements. Taking time to evaluate whether the changes resolve the transparency concerns of the CCAs will also allow the Commission to ascertain if there are any unintended consequences with the new requirements given the concerns expressed by the IOUs related to the provision of this data. In any event, the submittals of the monthly ERRA/PABA/PUBA activity reports (even the public versions) and additional underlying volumetric data, parties can track PABA balances on a monthly basis to get an indication of the balance that will need to be recovered in the following year's PCIA rates.

The IOUs acknowledge that the November Update portion of the ERRA Forecast proceeding is necessarily compressed given the timing of when the updated MPBs are issued by the Commission and

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[37] *See* D.18-10-019, OPs 6 and 8; *see also* D.19-10-001, OPs 3 and 4.

[38] *See* D.20-12-035, OP 8; D. 20-12-038, OP 4; D. 21-01-017, OP 6.

when a final decision must be received in order for the IOUs to implement in rates effective January 1. That said, the IOUs have developed and implemented internal processes that have enabled them to produce the November Update within one week of receiving the updated MPBs. Parties generally then have approximately one week to review the Update, which should be sufficient given that the Update is formulaic in nature and the information included should not raise any policy or substance issues. Where the IOUs believe there could be some benefit gained is in providing the Commission additional time to review the November Update submittals and draft proposed decisions ("PDs"). Based on current timelines, the work needed by the Commission to produce a timely PD is significantly compressed and generally falls over the Thanksgiving holiday. For these reasons, the IOUs are open to exploring potentially moving the target ERRA implementation date, and the complete Consolidated January 1 rate change, back slightly (*e.g.,* to a date within Q1)[39] to provide the Commission more time to draft the PD and ultimately adopt a final decision. The other potential benefit of slightly delaying the standard implementation timeframe is that it should allow for the use of more recorded actuals in the true-ups of the year-end balancing account balances[40] – as opposed to having to put into rates amounts that are still based on a forecast. At the same time, the IOUs continue to see the benefits of a January 1 implementation to best align cost recovery with the amounts being collected in rates, so a discussion on the benefits and tradeoffs of moving the target ERRA implementation dates may prove useful in the context of this proceeding.

2. Should Commission's Energy Division release the Market Price Benchmarks (MPBs) earlier than November 1 of each year? If yes, what is a reasonable date and why?

No, the Joint Utilities do not recommend the release of the MPBs earlier than November 1 each year. The timing of the MPBs is driven by the Brown Power Energy MPB, which forecasts the market value of Brown Power by taking the weighted average of Platts' market indices for a one-year strip of on-peak and off-peak power prices for the coming calendar year published over the period October 1 through October 31 of the prior year. It is appropriate to continue to use Platts' October forward market quotes for the Brown Power MPB because gas prices tend to be volatile during hurricane season, which lasts through at least September of each year. Additionally, releasing the MPBs earlier to update the

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[39] Based on differences in billing systems and other considerations, there may need to be different target timeframes for implementing the new ERRA rates for each IOU. Again, the target would be a Q1 implementation date each year for all IOUs, but the specific timing within Q1 may vary by IOU.

[40] *See* SCE Advice 4375-E, Table 1 and footnote 2.

ERRA Forecast prior to November of each year would require the use of more forecasted balancing account information for the ERRA Forecast Update in lieu of recorded actuals, which can impact the accuracy of the end-of-year balancing account activity.[41] Whereas with the November update, the IOUs only have to forecast October – December. Also, an earlier timeline would likely mean the final ERRA Forecast implementation advice letter typically submitted in January would require the use of forecasted data for December (and potentially November). Because numerous balance transfers occur in December, it is far more accurate to use actual recorded data for December, as discussed in response to Question II. 1, above.

3. Are there any other procedural or information sharing related modifications the Commission should consider to support more efficient implementation of PCIA issues within ERRA proceedings?

The Commission should also consider (1) improving the representation of the brown power benchmark component of the indifference calculation; (2) changes to PG&E's and SDG&E's ERRA trigger framework to consider offsetting bundled customer balances ; and (3) a renewable energy credit ("REC") tracking framework.

While the brown power benchmark is a well-established component of the indifference calculation that was left unchanged in the Phase 1 Decision, it can benefit from additional precision. Considering each IOU's respective PCIA supply portfolios when determining on peak/off peak weightings, rather than customer load, will improve the precision of the forecasted brown power index. Additionally, adopting monthly weighted on peak/off peak prices rather than a simple annual on peak/off peak average, will improve the forecasted precision further. Improved accuracy would decrease the magnitude of year-end over- or under-collected balances subject to true-up.

In D.11-12-018, the Commission examined whether the brown power MPB should be weighted to reflect variations in load shape by time-of-use periods. The Commission determined that the brown power MPB methodology should be modified to reflect load shape variations by time period.[42] As a

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[41] For example, if the MPBs were released October 1 and the IOUs ERRA Forecast updates occur the first week of October, the IOUs would use forecast data for September through December. In contrast, with a November update, the IOUs use forecast October through December balancing account activity. Also, an earlier timeline would likely mean the ERRA Forecast implementation advice letter would require forecasted data for December (and potentially November). Because some IOUs have balance transfers that occur in December, it is far more accurate to use actual recorded data for December, as discussed in response to Question II. 1, above.

[42] D.11-12-018, Ordering Paragraph 7.

result, the Commission adopted a weighting that aligned the brown power MPB with historical bundled load data. At the time, parties assumed that the bundled load profile (i.e., ***demand***) was not expected to differ substantially from the generation output portfolio (i.e., ***supply***) relevant to the Indifference Calculation.[43] The Commission therefore adopted bundled load data to weight the brown power MPB for estimating the CAISO energy market value of IOU supply portfolios while avoiding the use of confidential data concerning the IOU supply portfolio.[44]

Use of historical bundled load data as a proxy to reflect the supply portfolio is increasingly inaccurate. As discussed above, the IOUs have experienced and will continue to experience increased load departures, meriting reconsideration of whether a dwindling bundled load portfolio is an acceptable proxy of the supply portfolio. Existing and planned changes to IOU supply portfolios will continue to drive inaccuracies. In PG&E's case, the PCIA supply portfolio is comprised of a mix of generating technologies, including a large amount of solar, with different generating profiles that can result in more or less supply relative to the bundled load requirement depending on the hour and time of year. In Phase 1 of this Proceeding, the Joint IOUs cross-examined CCA witnesses concerning the previous methodology, which did not include a brown power true-up:

Mr. Archer: And under the [then] current methodology, departing load customers in PCIA are credited with the same flat energy price benchmark for each hour; correct?
Mr. Kinosian: There are two different values per Platts brown power prices. There's an on-peak value and an off-peak value, so there's two different values used in the PCIA calculation. What I'm addressing in my testimony is that those values … means that for PCIA calculation purposes, the benchmark is not adequately reflecting the value of the utilities' resources. …
Mr. Archer: So there's a lot of solar in the utilities' portfolio; correct?
Mr. Kinosian: Yes.
Mr. Archer: And solar tends to show up in the middle of the day; right?
Mr. Kinosian: Yes.
Mr. Archer: At the belly of the duck?
Mr. Kinosian: Possibly.
Mr. Archer: Sitting here today, do you think that [at] the belly of the duck, that solar power is generating [the Platt's average price] of megawatt hour on average in revenues?
Mr. Kinosian: I don't know. …[45]

The excerpt illustrates the disconnect between an IOUs' supply portfolio and bundled customer demand to weigh the forecast MPB. The non-dispatchable, renewable-heavy, PCIA-eligible portfolio

[43] D.11-12-018 at pp. 33-34.
[44] *Id.* at p. 34.
[45] R.17-06-026, May 11, 2018 Evidentiary Hearing Transcript, pp. 970-973.

(e.g., solar in the middle of the day and wind in the middle of the night) operates at periods not well-correlated to bundled customer demand. For solar resources, the generating profile of PCIA supply portfolios are not only different by time-of-day, but also by time-of-year.[46] As such, the brown power MPB methodology would benefit from a monthly volume-weighted approach. Both changes can be accomplished by using the PCIA ***supply*** generation presented in the Forecast cases instead of historical bundled load ***demand*** and the monthly Platt's on peak/off peak energy prices for the ERRA year.

Second, the Phase 1 Decision transformed the IOUs ERRA balancing accounts through the creation of PABA. Following the implementation of PABA, only market-based costs associated with bundled load are recorded to ERRA and recovered from bundled customers through the generation rate, and above-market costs incurred on behalf of both bundled and departing load customers are recorded to PABA and recovered from bundled customers through the generation rates, and from departing load customers through the PCIA.

The Joint IOUs recommend that the Commission adjust the ERRA trigger mechanism to consider PCIA-related bundled customer balances in PABA or other generation balancing accounts when determining whether an IOU is required to file an expedited ERRA Trigger Application. Consideration of amounts in PCIA-related and other bundled customer accounts will more accurately reflect the net balances associated with IOU bundled customers' generation costs and customer revenues. While IOU ERRA accounts were modified, the framework applicable to PG&E's and SDG&E's ERRA Trigger process is unchanged, merely considering ERRA balances when determining whether an expedited application or other notification action is required.[47]

For example, in 2019 and 2020, PG&E's ERRA account was over-collected and was not forecast to self-correct, causing PG&E to file expedited trigger applications. In both instances, PG&E's PABA account was significantly under-collected, and therefore PG&E did not pursue rate adjustments.[48] Conversely, if PG&E's ERRA account was under-collected, and its bundled customer PABA account was over-collected by a similar amount, PG&E would be required to file an ERRA Trigger Application.

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46 PG&E's planned retirement of Diablo Canyon Power Plant in 2024 and 2025 is expected to further distort the relationship between PG&E's bundled customer load profile and its PCIA-eligible supply portfolio.

47 SCE's ERRA Preliminary Statement addresses ERRA Trigger requirements and includes bundled service customers' pro rata share of the PABA in determining whether trigger applications are required.

48 *See* A.19-11-017 (forecasting a 2019 ERRA overcollection of $715 million and a bundled customer PABA undercollection of $611 million) and A.20-07-022 (forecasting a 2020 ERRA overcollection of $793 million and undercollected PABA balances of $534 million).

In this example, PG&E would not propose a bundled customer rate adjustment due to the offsetting bundled customer balancing account balance. Consideration of combined bundled customer balances is merited to save valuable party and Commission resources and to improve efficiencies.

Finally, PG&E's proposed use of banked RECs in the true-up of PG&E's 2019 PABA arose as a contested issue in PG&E's 2020 ERRA Forecast.[49] The Commission ordered an adjustment to PG&E's balancing accounts resulting in a bundled customer charge for a quantity of RECs in excess of that which PG&E generated and sold in 2019.[50] The Commission observed that a tracking framework may help resolve issues related to the use of banked RECs. The Joint Utilities support developing a framework to clarify requirements associated with the use of banked RECs to ensure bundled customers are not double charged if pre-2019 banked RECs are used for compliance, such as occurred in PG&E's 2020 ERRA Forecast.[51]

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[49] *See* D.20-02-047 at pp. 13-16.

[50] *See* D.20-02-027 at pp. 15-17 (stating [banked REC issues] are more appropriately addressed in the PCIA proceeding. *See also* D. 20-12-012 at pp. 5 (noting that the Commission deferred development of a proper tracking framework in the PCIA proceeding).

[51] *See* D.19-10-001, Finding of Fact 8 (stating that the methods set forth in that Decision apply to RECs generated commencing January 1, 2019 and going forward).

Respectfully Submitted,

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Dated: January 22, 2021