BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA


Rulemaking 13-11-005
(Filed November 14, 2013)

COMMENTS OF MARIN CLEAN ENERGY REGARDING REGIONAL ENERGY NETWORKS

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I. INTRODUCTION

Pursuant to the Administrative Law Judge’s Ruling Requesting Comments Re Regional Energy Networks (“Ruling”) issued on January 12, 2016 (“ALJ Ruling”), Marin Clean Energy (“MCE”) submits these comments responding to each of the questions posed in the ALJ Ruling.

MCE is the only Community Choice Aggregator (“CCA”) in the state that is currently an Energy Efficiency (“EE”) Program Administrator (“PA”). MCE consistently collaborates with the Regional Energy Networks (“REN”) as a fellow local government PA with an overlapping service territory and has had ample opportunity to observe the success of REN EE programs.

II. RESPONSES TO QUESTIONS

1. Does REN program performance warrant continuing REN programs, regardless of whether RENs remain PAs? Which programs should continue to receive expanded or reduced funding/ or be terminated?

Simply put, REN programs are successful and the Commission would be well-served in continuing and expanding REN administration of EE programs. RENs have met the three criteria
specified in Decision (“D.”) 12-11-015 by which their program proposals were evaluated.\(^1\) It was not necessarily cost-effectiveness that drove decision-making in the RENs, but rather the focus on filling in gaps in programs.\(^2\) And RENs have succeeded in this task, successfully administering a variety of program that achieve savings, comply with Commission reporting requirements, and collaborating with other entities, such as MCE.

In addition, as local government entities, RENs are necessarily more connected with the communities they serve. With their guidance by elected and appointed local government officials, RENs reflect the communities they serve. In addition, local government requirements, such as Brown Act and other public records rules, ensure transparency in programming. For these reasons, any budgetary and program modifications proposed by the RENs should not be subject to any oversight from the incumbent Investor-Owned Utility (“IOU”).

For these reasons, MCE recommends that the Commission continue REN EE programs.

2. Should RENs remain PAs in connection with whatever portfolio of programs they oversee?

2.1 RENs Should Continue as PAs and Retain Program Design Autonomy

RENs should remain PAs of EE portfolios they oversee. MCE can attest that a diversity of PAs creates laboratories for creative EE program design and implementation. MCE has already observed the success of the BayREN multifamily program, and has taken unique

\(^1\) These criteria are: 1. Activities that utilities cannot or do not intend to undertake. 2. Pilot activities where there is no current utility program offering, and where there is potential for scalability to a broader geographic reach, if successful. 3. Pilot activities in hard to reach markets, whether or not there is a current utility program that may overlap. D.12-11-15 at 17.

\(^2\) “It should also be noted that many of the REN program plans address hard to reach market segments that are generally more expensive than average to deliver. REN proposals should not be punished for that, because, if successful, their pilot approaches could lead to breakthroughs for more cost-effective solutions in the future.” D.12-11-015 at p. 19.
elements of program design, such as a simple, easy to understand program incentive, and applied this tactic locally with great success. Local governments, as discussed above, are uniquely situated to design and deliver programs specifically responsive to the needs of their communities. To foster the ability to innovate and meet the specific needs of local governments, RENs should have the ability to propose program design changes autonomously to the CPUC, without first seeking the oversight or approval of the IOU who may hold the role of fiscal agent for the REN.

2.2 New REN Applications Should Be Approved

As innovators, RENs have opportunities to fill niches that are often overlooked. MCE joins the recommendations from the Opinion Dynamics study on RENs\(^3\) to create more robust opportunities for programming and significant regulatory support in order to successfully launch entities.

2.3 RENs Should Become Permanent PAs and No Longer be Subject to Pilot Status

RENs should become permanent PAs and continue through the rolling portfolio cycle. Given the conclusion and recommendations of the Opinion Dynamics study, RENs are a proven strategy in EE program administration and reducing greenhouse gas emissions. MCE recommends that the Commission continue to support robust development of existing and new RENs.

III. CONCLUSION

MCE thanks Commissioner Peterman and Administrative Law Judge Fitch for their thoughtful attention to these comments regarding RENs.

\(^3\) Opinion Dynamics Study, page 5.
Respectfully submitted,

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February 26, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2015 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast

Application 14-05-024 (Filed May 30, 2014)

(U 39 E)

RESPONSE OF MARIN CLEAN ENERGY AND CITY OF LANCASTER TO OPTIONAL HOMEWORK ASSIGNMENT IN PREPARATION FOR THE MARCH 8 WORKSHOP ON PCIA REFORM

February 16, 2016

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ON BEHALF OF
MARIN CLEAN ENERGY
AND CITY OF LANCASTER
SUMMARY OF RECOMMENDATIONS

1. The Commission should issue a single source document detailing the full PCIA calculation process from start to finish and present that document to interested parties prior to the convening of the March 8 workshop.

2. The Commission should consider PCIA reform in light of: (1) the increase in CCA load and potential CCA load; (2) further applicability of PCIA to other loads, such as green tariff shared renewables, customer generation departing load, and potentially net energy metering; (3) increased maturity in the renewable energy market; and (4) an increased statewide emphasis on solutions to climate change.

3. The Commission should require greater transparency of the PCIA inputs by making contract information public upon signature, including information such as pricing, volumes and terms of each IOUs contract contributing to the PCIA.
   - Alternatively, this contract information should be public no later than one year of signature.
   - Alternatively, the Commission should adapt confidentiality rules to: (1) review IOU determinations of public and confidential information; (2) direct IOUs to make information public when it has already been available in other public forums; and (3) determine whether the confidentiality rules are serving the public interest.
   - Alternatively, the Commission should create a category of Public Agency Participants that have a higher level of access to IOU contract information that is currently deemed confidential for Market Participants.
   - Alternatively, the Commission should direct the IOUs to provide 10-year forward forecasts of Total Portfolio Costs and percentage breakdowns of RPS and non-RPS procurement.

4. In order to ensure that non-confidential information is disclosed, the Commission should strongly and swiftly enforce rules and create consequences for failure to disclose non-confidential information that relates to the PCIA calculation. In addition, the Commission should require the IOU to reimburse impacted parties for time and resources spent preparing multiple data requests, meet and confer sessions, and motions to compel.

5. To ensure that the Total Portfolio approach to PCIA excludes avoidable costs, the Commission should: (1) require IOUs to forecast and plan around likely load departure in

...
accordance with D.15-10-031; (2) through an annual audit, require an IOU to mitigate
damages for Power Purchase Agreements; (3) through an annual audit, require an IOU to
curtail generation from Utility-Owned Generation when above-market costs are avoidable.

6. The Commission must clearly define either prior to or at the March 8 workshop what the
present limitations are for the stranded cost recovery of conventional, renewable, and UOG
resources, because D04-12-048 is self-contradictory and vague.

7. In order to set appropriate duration limits for the PCIA, stranded cost recovery should be
limited to 10 years for all resource types.

8. To limit PCIA volatility and uncertainty, the Market Price Benchmark should consider 5
years of natural gas prices instead of the current single year spot-market price.

9. The Commission should develop alternatives to the volatile year-by-year PCIA through
providing a Menu of Options for repayment that departing load providers can choose from in
order to prioritize their own mission and values.

10. The March 8, 2016 workshop should limit its discussion on Question 3 to clearly define what
is considered “a very large [departing] load.” Further considerations regarding how to treat “a
very large [departing] load” should then be considered in a second workshop.

11. At a policy level, the Commission should strive for PCIA reform that is both fair to all forms
of departing load and flexible enough to enable LSEs to plan around the PCIA and effectively
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I. INTRODUCTION

Marin Clean Energy (“MCE”) and the city of Lancaster, operating its Community Choice Aggregation (“CCA”) program through Lancaster Choice Energy (“LCE”) (together with MCE, the “CCA Parties”) provide the following responses to the “optional homework assignment for Power Charge indifference Adjustment (PCIA) Workshop participants” circulated to interested parties by California Public Utilities Commission (“Commission” or “CPUC”) Energy Division staff on January 22, 2016. In accordance with Commission Decision (“D.”) 15-12-022, the Commission plans to convene a workshop to discuss PCIA reform. This workshop is presently scheduled from 10 AM to 3 PM on March 8, 2016. The CCA Parties provide these responses to Energy Division staff and the instant proceeding’s service list to recommend reforms to the PCIA to increase the transparency of the fee calculation, hold the Investor-Owned Utilities (“IOUs”) accountable for minimizing stranded costs, and ensure the PCIA is more just and reasonable.
II. BACKGROUND

MCE has been closely engaged in the Pacific Gas and Electric Company’s (“PG&E”) Energy Resource Recovery Account (“ERRA”) annual proceedings since MCE began serving its customers in May 2010. Since MCE is the first operational CCA program in California, it has led advocacy on many CCA-related regulatory matters before the Commission. MCE currently serves over 171,000 customers in Marin County, unincorporated Napa County, and the cities of Richmond, El Cerrito, San Pablo, and Benicia. MCE has already played an active role in this proceeding to ensure the proper assignment of vintages to CCA customers.

Lancaster is a thriving community of nearly 160,000 residents located approximately one hour north of Los Angeles. Attainable housing and recent economic growth have made Lancaster a very attractive choice for families and businesses that are looking to relocate, but wish to enjoy all the advantages that Southern California has to offer. Lancaster continues to aggressively pursue alternative energy solutions in hopes of bettering the current and future environmental and economic conditions of its community and region. In that context, the Lancaster City Council approved a CCA Implementation Plan for Lancaster Choice Energy in 2014, which was certified by the Energy Division on March 13, 2015. Lancaster is now the third operational CCA program in California, and the first in Southern California Edison Company’s (“SCE”) territory. Lancaster is interested in issues raised within the scope of PG&E’s ERRA proceeding, specifically as it relates to PCIA and its reform, as the outcome will impact all CCA customers.¹

¹ Lancaster’s motion for party status in this proceeding was granted on March 11, 2015. Lancaster has joined with MCE in filing various pleadings in this phase of the proceeding, most recently also joining with MCE and Sonoma Clean Power (“SCP”) to file an opening brief and a reply brief on September 4, 2015 and September 25, 2015, respectively.
III. HOMEWORK ASSIGNMENT RESPONSES

A. QUESTION 1: Please indicate your understanding of how the PCIA is calculated, identifying, in as much detail as possible, each input to that calculation.

It is the CCA Parties’ understanding that the PCIA represents the unavoidable above-market costs of the IOU electricity procurement portfolios that become stranded when load departs from that IOU’s bundled electricity services to take electricity generation services from another Load-Serving Entity (“LSE”), such as an Electricity Service Provider (“ESP”) or CCA. The PCIA is imposed to ensure that such departing load remains responsible for paying any procurement costs incurred on their behalf by the utility prior to their departure. The methodology for calculating the PCIA is most clearly set forth in Commission Resolution E-4475 – Exhibit A, along with the Chapter 9 of PG&E’s Opening Testimony within this proceeding. Resolution E-4475 was issued by the Commission on May 10, 2012 when the PCIA methodology was last modified in order to differentiate the market price of renewable power from conventional power purchases by adopting a “Green Adder.” As such, E-4475 details the calculations specific to the Market Price Benchmark (“MPB”), the Capacity Adder, and the Green Adder. In addition to these formulas, there is the calculation of the utilities Total Portfolio Indifference which determines the PCIA revenue requirement for each vintage of departing load. There is also the PCIA rate calculation which spreads the revenue requirement across the different customer classes.

While PG&E’s Opening Testimony and Resolution E-4475 are the most succinct and complete references to the manner in which the PCIA is calculated, they are by no means exhaustive. For example, as part of the PCIA rate calculation component, the revenue requirement is allocated to distinct customer classes on a “Top 100 Hours” basis, where each class is allocated their share of the PCIA revenue requirement based upon their class’ average
top 100 hour loads overall based on recent usage data.\(^2\) The usage of this methodology is not explicitly called out in either PG&E’s Opening Testimony or Resolution E-4475. In order to facilitate a common understanding, the CCA Parties recommend the Commission issue a single source document detailing the full PCIA calculation process from start to finish and present that document to interested parties prior to or at the March 8 workshop.

For others’ convenience, the CCA Parties include Chapter 9 of PG&E’s Opening Testimony and Exhibit A from E-4475 within the Appendix to this homework response.

**B. QUESTION 2: Do you believe the current PCIA methodology should be changed? If so, how and why? Please be as specific as possible.**

The current PCIA methodology is flawed in numerous ways and should be modified to remedy these flaws. The existing methodology is executed in a highly non-transparent manner in which the IOUs have no incentive to minimize the “stranded costs” that feed into the PCIA calculation. This results in an extremely volatile, annually adjusted rate with no clear duration limit. The current PCIA methodology results in an unjust and unreasonable rate for CCA ratepayers that purchase electricity from cleaner sources than the IOUs’ bundled electricity portfolio mix. Not only does the existing methodology result in an unreasonable rate that violates the core mission of the Commission to ensure reasonable rates, but also the PCIA obstructs the abilities of California’s ratepayers to accelerate the State towards meeting its Climate Change goals initially set forth in Assembly Bill (“AB”) 32 (2006) and recently expanded in Senate Bill (“SB”) 350 (2015).

The Commission should take reasonable steps to change the PCIA methodology so that it is calculated in a transparent manner, with clear accountability for the IOUs to minimize the

\(^2\) See D.00-06-034 for a detailed explanation of the “Top 100 Hours” methodology.
costs that go into it, so that the resulting rate is both just and reasonable for CCA ratepayers. These steps begin with revisiting the policies that inform the PCIA calculation so that they can be revised to more fairly account for CCA programs, the maturity of the renewable electricity market, the increasing diversity of forms of departing load, and the State’s ambitious Climate Change goals.

The CCA Parties appreciate the Commission’s continuing willingness to consider changes to and clarifications of the PCIA methodology. Changes and clarifications are being considered in the context of the PCIA vintaging issue. Additional changes to and clarifications of the PCIA are warranted, as further described below.

In the time since when the Commission last revised the PCIA methodology (May 2012) numerous factual circumstances have arisen that prior Commission policy has not considered:

1) Increase in CCA Load and Potential CCA Load. Load departures due to CCAs have expanded from one instance in PG&E’s service territory to a statewide movement. As such, D.15-10-031 now directs both PG&E and SCE to forecast for CCA departing load as part of their biannual Bundled Procurement Planning (“BPP”) process.

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3 See, e.g., D.08-09-012 at 57-58 (“Given the potential long-term nature of the charge, we must allow for the possibility that certain future circumstances may result in a need to modify the NBC related processes adopted in this decision.”). See also D.13-08-023 at 17 (“The Commission remains committed to ensuring that Community Choice Aggregators and other non-utility [load-serving entities] may compete on a fair and equal basis with regulated utilities. Towards this end, we will continue to consider both the mechanics and overall fairness of cost allocation and departing load charge methodologies proposed in the future, with the specific goal of avoiding cross-subsidization.”).

4 See Assigned Commissioner’s Ruling Amending Scope and Setting Out Briefing Schedule, dated August 10, 2015, at 3 (“When the Commission issued its line of decisions and resolution on [Community Choice Aggregators] and vintaging issues, the implementation of CCA programs was in its nascent stage.”).

5 See D.15-10-031 at Ordering Paragraph 1(e) and 1(o).
2) Further Applicability of PCIA to Other Loads. Additional forms of departing load are now subjected to the PCIA. For example:

a) Green Tariff Shared Renewables: In 2013, SB 43 authorized the IOUs to begin offering optional premium electricity products informally known as “Green Tariffs.” D.15-01-051 determined that participants in these programs will pay the PCIA.6

b) Customer Generation Departing Load: In 2015 the 3,000 MW cap for Customer Generation Departing Load (“CGDL”)7 was exceeded, thereby terminating prior exemption for this type departing load from non-bypassable charges including the PCIA.8

c) Potential Applicability to Net Energy Metering: The Commission recently approved D.16-01-044 on the Net Energy Metering (“NEM”) successor tariff. Although the decision did not go so far as to apply the PCIA to the self-generation of bundled NEM customers, there is the very real possibility that this departing load segment’s exemption from the PCIA may expire too.

3) Increased Maturity in the Renewable Energy Market. The renewable electricity market has reached a state of maturity prompting the Commission to revise its policies to reduce the subsidies provided to the renewable electricity industry. This is evident in D.16-01-044 and D.15-07-001.9

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6 See D.15-01-051 at Conclusion of Law 100.
7 See D.03-04-030
8 See PG&E Advice Letter 4743-E at Attachment 1.
9 D.16-01-044 revised and reduced the incentives for ratepayer participation in NEM. D.15-07-001 significantly revised residential rates including reform of the Time of Use (“TOU”) rate structures which are fundamental to the economic viability of NEM.
4) Increased Emphasis on Solutions to Climate Change. Through the recent passage of SB 350 (2015), the State of California has expanded its commitment to reducing greenhouse gas emissions and adopting renewable electricity as remedies for combating Climate Change.

All four of these significant factors must be closely considered by the Commission when revising the policies that inform the PCIA methodology. By considering these robust changes to the competitive electricity providers market, the renewable electricity market, and State electricity policy, the CCA Parties provide the following proposals to improve and refine the PCIA methodology.

1. REQUIRE GREATER TRANSPARENCY OF PCIA INPUTS

Under the guise of compliance with Commission policies on confidential information, the IOUs extensively – and excessively – redact the information used to determine the annual PCIA rate. However, much of this same information is being presented in other public forums, such as through the California Energy Commission (“CEC”) Integrated Energy Policy Report (“IEPR”) and through the Federal Energy Regulatory Commission (“FERC”) Form 1 filings.\textsuperscript{10} Instead of disclosing this information, the IOUs remain insistent that information such as contract start and end dates, volumes and cost information remain confidential and redacted before the Commission. The CCA Parties believe the IOUs are not complying with existing Commission decisions, including D.06-06-066, with regards to making contract information publicly available after 3-years’ time. This lack of transparency continues to provide the IOUs with a competitive advantage over other LSEs, such as CCAs.

\textsuperscript{10} It is the CCA Parties’ understanding that the IOUs present load and generation forecasts to the CEC to inform their IEPR process. It is also the CCA Parties’ understanding that the IOUs present annually recorded production and cost information on a per resource basis through their Form 1 filings with FERC. CCAs do not currently have access to this forecast information.
Presently the CCA Parties, other CCAs, and local governments considering forming or participating in CCAs have almost no visibility into the drivers that influence the annual calculation of the PCIA rate. As highlighted during the 2016 PG&E ERRA proceeding by MCE’s testimony, briefing, and comments, CCAs have little opportunity to plan for and adjust to fluctuations in the PCIA rate. For example, it was not until November 2015 that MCE staff was able to access the information necessary to determine that PG&E sought to double the PCIA rate that the majority of MCE’s residential customers pay (2012 vintage) effective January 1, 2016.

Furthermore, as market participants, there is an excessive level of redacting applied to the information that CCA staff is able to attain from PG&E. For example, when MCE sought contract-specific information from PG&E through discovery, of the 275 contracts presented by PG&E as factoring into the PCIA calculation, MCE was only able to see the full information for seven. MCE therefore has incomplete information for over 97% of the contracts that are represented in the PCIA fee charged to its customers. MCE is undertaking efforts to meet and confer with PG&E staff to determine whether all of this information is appropriately redacted per D.06-06-066. MCE and other CCAs also do not have access to the information used to determine the Green Adder in the Market Price Benchmark (“MPB”), and IOU load information that materially impacts the annual PCIA calculation as well. As such, CCAs have no reasonable means to anticipate significant changes in the annual PCIA rate and plan accordingly. Furthermore, CCAs have no basis upon which to rely that the IOUs are ensuring the annual PCIA rate is just and reasonable.

See MCE’s filings within A.15-06-001.

PG&E’s November Update within A.15-06-001 was served on November 5, 2015 requesting rate changes effective 57 days later on January 1, 2016.
PROPOSED SOLUTIONS:

i. **Solution: The Pricing, Volumes and Term of Each of the IOUs' Contracts That Make up the PCIA Should Be Made Public Upon Approval of the Contract or Resource**

As a general matter, once a contract is signed with a CCA and approved for its procurement portfolio, that contract and all of its specifics (including price and output) are publicly available information. There are certain exceptions to this statement, but they are relatively limited. Some public agencies even provide information before contract execution as part of the administrative review process. For example, the city of Palo Alto discloses contractual information as part of its city council review process, including the full Power Purchase Agreement with contract rate information. Similarly, MCE includes a report on approved contracts as part of its Board Packet, including information on contract amount and term.

The CCA Parties recommend that the IOUs follow this same practice in order to allow proper vetting and full transparency. The CCA Parties are not alone in this recommendation. In a ruling with respect to the Renewables Portfolio Standard (“RPS”) program, the Commission vetted a proposal by the CPUC Energy Division that sought to clarify and improve confidentiality rules for RPS-related contracts. Under the Energy Division’s proposal, for RPS procurement contracts that require Commission approval via resolution, the contract price must be publicly disclosed in the draft resolution (and the final resolution) approving the contract.

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13 See, e.g., Memorandum to City of Palo Alto’s Utilities Advisory Commission from the Palo Alto Utilities Department, Attachment B (Jan. 13, 2016) (for power purchase agreement).

14 See, e.g., MCE Board of Directors Meeting at Section 5(C)(2) (Jan. 21, 2016) (for an update on approved contracts).


16 RPS Ruling at 20.
For RPS procurement contracts submitted for Commission approval via (non-Tier 3) advice letters, the contract price would be publicly disclosed at the time the advice letter is filed. The CCA Parties encourage the Commission to reconsider the proposal advanced by the Energy Division.

**ii. Alternate Solution: The Pricing, Volumes and Term of Each of the IOUs' Contracts That Make up the PCIA Should Be Made Public No Later Than One Year After Approval of the Contract or Resource**

In the event the IOUs can provide meaningful reasons why contract pricing, volumes, and/or terms should remain confidential immediately after execution or approval, the Commission should evaluate whether those rationales outweigh the benefits of transparency and accountability. The Commission may consider that contracts should be made public no later than one year after such execution or approval since much of the pricing and delivery information can be deduced from the IOUs’ FERC Form 1 filings (at significant cost and burden for reviewers).

**iii. Alternate Solution: The Commission Should Revisit Its Confidentiality Rules to Ensure All Information That Is Non-Confidential in Other Reports Is Non-Confidential Under CPUC Rules**

As discussed above, IOUs disclose information through the IEPR process, FERC Form 1 and other requirements. In order to ensure consistency with these other disclosure rules, the Commission should: (i) review the IOU presentation of both “public” and “confidential” information specific to the PCIA for compliance with present Commission rules; (ii) direct the IOUs to provide information specific to the PCIA that is available (although perhaps in different formats) in other public forums, such as the CEC and FERC; and (iii) revisit the rationale behind the current confidentiality rules to determine whether they are serving the public interest.

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17 RPS Ruling at 23.
With regard to this latter point, the CCA Parties urge the Commission to reconsider the public interest policies that are promoted (or suppressed) by the Commission’s current confidentiality rules. Thankfully, the Commission is seriously considering some of these matters in R.14-11-001. The Order Instituting Rulemaking (“Confidentiality OIR”) in that proceeding echoes many of the same policy statements espoused by the CCA Parties – statements that warrant serious reexamination of the Commission’s current confidentiality rules for the PCIA inputs. The following brief excerpt from the Confidentiality OIR underscores this point:

Further, the Legislature has declared that “access to information concerning the conduct of the people’s business is a fundamental and necessary right of every person in this state.” An agency must base a decision to withhold a public record in response to a CPRA request upon the specified exemptions listed in the CPRA, or a showing that, on the facts of a particular case, the public interest in confidentiality clearly outweighs the public interest in disclosure. The CPRA favors disclosure, and CPRA exemptions must be narrowly construed. The fact that a record may fall within a CPRA exemption does not preclude the agency from disclosing the record if the agency believes disclosure is in the public interest. Unless a record is subject to a law prohibiting disclosure, CPRA exemptions are permissive, not mandatory; they allow nondisclosure but do not prohibit disclosure.\textsuperscript{18} \textbf{Alternate Solution:} The Commission should adopt a third category under its confidentiality rules


Presently the Commission’s confidentiality rules consider just two types of participants engaging before the Commission: market participants and non-market participants. Much of the justification for the protections of information under these rules is to prevent manipulation and gaming by market participants that both compete with IOU’s bundled electricity services and engage in selling electricity to the IOUs. In addition to revising the current confidentiality rules,

\textsuperscript{18} Confidentiality OIR at 3 (internal citations omitted).
the Commission should also create a third category of participant to be considered within them: Public Agency Participants.

In the case of CCAs, CCAs are public agency market participants that compete with the IOUs’ electricity generation services, but as a general rule CCAs are not engaged in the business of selling electricity to the IOUs. In addition, with the possible exception of a very large CCA, CCAs are not large enough to alter market prices. As such, the CCA Parties believe it would be reasonable to create a third category for the purpose of reviewing confidential material (Public Agency Participants). This category of market participant does compete with IOUs’ bundled services and are impacted by the PCIA, but does not engage in wholesale seller’s arrangements with the IOUs. As such, Public Agency Participants do not present the same level of risk for manipulation and should be permitted a higher level of access to information considered “confidential” under the present rules, subject of course to a non-disclosure agreement.

This approach comports with the unique status afforded the California Independent System Operator Corporation’s (“ISO”) Reviewing Representative under the Commission’s Decisions. Presently, under the Model Protective Order provided in D.06-12-030, D.08-04-023, and clarified D.11-07-028, the ISO can review confidential information without violating confidentiality rules. The rationale for this unique approach for the ISO was first expressed in D.06-12-030, where the Commission distinguished the ISO from other market participants, noting that “Its incentive is…not to drive up (or down) the price of electricity out of a desire to enhance profits for itself” and that “the CAISO is more akin to a state agency than it is to a market participant.”19 CCAs are local agencies that, similar to the ISO rationale above, do not seek to enhance shareholder profits, and are primarily concerned with providing clean and

19 Decision 06-12-030 at 35, note 44.
reliable power. Thus, the Commission should consider allowing CCAs and other public agencies without a shareholder profit motive to review information while participating in the energy market, subject to a nondisclosure agreement.

v. Alternate Solution: The Commission Should Direct the IOUs to Provide 10-Year Forward Forecasts of Total Portfolio Costs and Percentage Breakdowns of RPS and Non-RPS

Due to the present lack of transparency surrounding the PCIA methodology, the Commission should direct the IOUs to present CCAs and other non-IOU LSEs with a 10-year forecast of the IOUs’ Total Portfolio Costs and volumes, by vintage, and the percentage renewable to non-renewable composition of this portfolio for each year. Such a projection will allow CCAs to approximate potential PCIA rates for coming years and conduct more reasonable long-term planning around the potential changes to the PCIA.

2. ENSURE NON-CONFIDENTIAL INFORMATION IS DISCLOSED

As discussed in Section 1 above, the IOUs have often taken the stance of using the confidentiality rules to protect information that is not confidential or market sensitive. This results in a lack of transparency and wasted time on the part of parties and the Commission to address meet and confer requirements and motions to compel.

PROPOSED SOLUTION:

i. Solution: The Commission should strongly and swiftly enforce rules and create consequences for failure to disclose non-confidential information

In addition to reforming the confidentiality rules as discussed in Section 1, the Commission must enforce those rules and ensure that IOUs are appropriately disclosing non-confidential information. If the IOUs continue to obfuscate information through over-redaction when Commission policy clearly states such information should be made public, there should be direct consequences, including fees or penalties, as well as a requirement that the IOU reimburse
impacted parties for time and resources spent preparing multiple requests, meet and confer sessions, and motions to compel.

3. **ENSURE THAT THE TOTAL PORTFOLIO APPROACH EXCLUDES AVOIDABLE COSTS**

The Commission has mandated that the PCIA must represent only the unabavoidable\textsuperscript{20} above-market stranded costs.\textsuperscript{21} These costs must be unavoidable, above-market costs of the IOU electricity procurement portfolios that become stranded when load departs from that IOU’s bundled electricity services to take electricity generation services from another LSE, such as an ESP or CCA. The PCIA is imposed to ensure that such departing load remains responsible for paying any procurement costs incurred on their behalf by the utility prior to the departure. The Commission has variously referred to this principle as the “fair share” principle, which has been summarized by the Commission as follows: “[T]he rule is that when costs are incurred on its behalf, that customer must pay its fair share of the costs. A corollary rule is that if no costs are incurred on its behalf, then the customer’s fair share can be determined to be zero.”\textsuperscript{22}

It is in the IOUs’ competitive interest to pad as many costs into the PCIA as possible because the PCIA directly reduces the margin that CCAs and other non-IOU LSEs have to compete with the IOUs’ bundled electricity services. Since there is no transparency within the calculation and there is no clear means by which above-market costs are determined to be avoidable versus unavoidable, the CPUC must ensure that the IOUs are not leveraging the PCIA construct for their competitive advantage by assigning excessive and unnecessary procurement

\textsuperscript{20} See California Public Utilities Code Section 366.2(f)(2)

\textsuperscript{21} D.04-12-046 at 65.

\textsuperscript{22} D.08-09-012 at 10-11.
costs to the PCIA. Without proper transparent review, there is no way to determine whether or not there are improper inclusions in the PCIA rate. Based on its response to MCE’s recent discovery requests, it seems PG&E has taken no steps to mitigate the costs that factor into the PCIA. This is despite the fact that it is clearly the Commission’s objectives to minimize the PCIA and promote good resource planning by the IOUs.\textsuperscript{23}

Though both statute and Commission Decisions clearly state the PCIA should only include \textit{unavoidable} above market costs,\textsuperscript{24} the CCA Parties believe the present vintage “Total Portfolio”-based methodology\textsuperscript{25} for determining the above market costs that factor into the PCIA does not fully consider what costs are avoidable and what are not. There are a number of strategies to employ to avoid above-market costs:

(i) Forecasting and planning around likely load departure (as D.15-10-031 directs) will reduce unavoidable costs due to CCA load departures;

(ii) Require an IOU to mitigate damages annually for Power Purchase Agreements (“PPAs”). For example, whenever an IOU has an option to extend, amend, renegotiate, terminate, reduce the duration, or reduce the volume of electricity purchased through a specific contract and the IOU chooses to exercise this option, then the costs associated with that resource should no longer be considered unavoidable for existing departed load because the IOU has chosen to retain the resource in light of the existence of this already departed load;

(iii) Require the IOUs to curtail generation from Utility-Owned Generation (“UOG”) when resources with above-market costs are avoidable. If the IOU continues to generate

\textsuperscript{23} See D.04-12-046 at 29. (“Our complementary objective is to minimize the CRS…and promote good resource planning by the utilities.”).

\textsuperscript{24} See California Public Utilities Code Section 366.2(f)(2) and D.04-12-046 at 65.

\textsuperscript{25} See PG&E’s Opening Testimony – Chapter 9.
electricity beyond the minimum from this resource, then the costs of the curtailable portion of the resource’s generation should be considered avoidable costs and not included within the PCIA calculation.

PROPOSED SOLUTIONS:

i. **Solution: Ensure Proper Forecasting of CCA Departing Load Occurs in Accordance With D.15-10-031**

Though D.15-10-031 clearly directs for both PG&E and SCE to forecast for departing load due to CCAs over a 10-year horizon, this Decision fails to direct SDG&E to make similar forecasts despite strong interest in CCA formation being displayed within its service territory. As an aside, it is important to note that D.15-10-031 is not the first pronouncement on this matter. Assembly Bill (“AB”) 1723 was passed by the Legislature in 2005 for the purpose of quantifying the amount of forecasted departing load. The purpose of AB 1723 is summarized as follows: “the purpose of this bill is to make public the IOUs' forecasts to determine whether the IOUs pre-purchased electricity on behalf of departing customers.” Unfortunately however, the Commission has given little practical effect to this law. Nevertheless, the Commission has repeatedly directed the IOUs to not rely on static, standardized assumptions regarding CCA departing load, but rather the IOUs are to employ dynamic means (informed by “information provided by the CEC and from other sources…”) to “estimate reasonable levels of expected DA and CCA departing load….”

Additionally, the implementation of this forecast and the consideration of how to address a scenario in which a forecast does not match the observed CCA load departures has yet to be

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26 See Stats. 2005, ch. 703, adding Section 25302.5 to the Public Resources Code.
27 See Assembly Bill Analysis of AB 1723, August 2005.
discussed within the record of a Commission proceeding. If more load departs than was forecasted for in a certain year, will all the load that departs during that year be subjected to the stranded costs associated with this unexpected load departure? Or will only the segments of load departure that exceed the forecast be subjected to the PCIA for that specific vintage? The Commission must examine these issues and provide clear guidance so that going forward timely and accurate forecasts of CCA departing load can reduce the amount of *unavoidable* stranded costs due to CCAs’ customers.

**ii. Solution: Require the IOUs to Mitigate Damages Annually for PPAs**

Mitigation of damages is a foundation of a wide range of areas of law. Supra. As a general matter, the Commission has broad authority to disallow recovery of costs that are unreasonable. If it truly is the Commission’s objective to minimize the PCIA, promote good resource planning by the IOUs and promote just and reasonable rates, then the Commission must require the IOUs to mitigate damages (i.e. the occurrence of above-market stranded costs) that factor into the PCIA. When presented with a reasonable opportunity to avoid the continuance of such above-market stranded costs, the Commission should direct the IOUs to act upon such

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29. *See, e.g.,* *Agam v. Gavra*, 236 Cal. App. 4th 91, 111 (2015) (“The doctrine of mitigation of damages holds that a plaintiff who suffers damage as a result of … a breach of contract … has a duty to take reasonable steps to mitigate those damages and will not be able to recover for any losses which could have been thus avoided. Under the doctrine, [a] plaintiff may not recover for damages avoidable through ordinary care and reasonable exertion.” (Internal citations omitted.))

30. *See, e.g., In Re Pac. Gas & Elec. Co.*, 199 P.U.R.4th 177 (Feb. 17, 2000) “Under Sections 701 and 728, the Commission has the authority to determine what is just and reasonable, and to disallow costs not found to be just and reasonable. In particular, the Commission ‘has the power to prevent a utility from passing on to the ratepayers unreasonable costs for materials and services by disallowing expenditures that the commission finds unreasonable.” (Internal citations omitted.)

31. D.04-12-046 at 29.
opportunities. Failure to do so will result in excessive costs for both bundled and unbundled ratepayers alike.

In order to ensure that the IOUs’ are acting upon all of these opportunities to mitigate costs, the Commission should conduct an annual audit (perhaps as part of the annual ERRA compliance proceedings for each individual IOU) to determine whether the IOU has appropriately taken steps to mitigate avoidable above-market costs. For PPAs, this audit would consider whether the IOUs have had the option to extend, amend, renegotiate, terminate, reduce the duration, or reduce the volume of electricity purchased for each contract that factors into the IOU’s PCIA calculation.

**iii. Solution: Require the IOUs to Curtail Generation Annually From UOG When Above-Market Costs Are Avoidable**

For UOG, this audit would consider whether generation from above-market UOG could be curtailed to any extend while still recovering the necessary amount of operational and sunk capital costs that need to be recovered in rates. For any instances where the IOU has failed to exercise its ‘option’ to avoid further above-market stranded costs associated with these resources, this failure to mitigate costs would result in a disallowance for the utility and the removal of these costs from PCIA rates.

**4. Set Clear and Appropriate Duration Limits for Stranded Cost Recovery**

Current Commission policy is unclear at best regarding the duration limits for stranded cost recovery of conventional, renewable, and UOG resources. The Commission last addressed these policy matters in the 2004 Long-Term Procurement Plan (“LTPP”) proceeding cycle with D.04-12-048. However upon closely examining this Decision, the policy guidance that it provides regarding stranded cost recovery appears self-contradictory and vague.
With regards to conventional resources, the dicta and Conclusions of Law (“COL”) sections of D.04-12-048 seem to clearly intend for stranded cost recovery to occur “over either the life of the contract or 10 years, whichever is less.” 32 Yet, Ordering Paragraph (“OP”) 10 suggests a “15-year standard for new fossil-fueled resources acquired by the utilities.” 33 While CCA Parties have conservatively interpreted D.04-12-048 to authorize the stranded cost recovery for conventional resources for no more than 10 years, the CCA Parties believe the IOUs may have come to a different conclusion based upon PG&E’s response to discovery. 34

With regards to renewable resources, there is vagueness regarding the upward limitations for stranded cost recovery. Though the dicta, COL, and OP in D.04-12-048 do seem to agree that for renewable generation stranded cost recovery should be allowed “over the life of the contract,” yet it remains unclear to the CCA Parties what is the upwards limit for the life of a renewable contract. Dicta within D.04-12-048 suggests the life of renewable contracts span up to 20 years, 35 yet PG&E states within its response to MCE Data Request 003 Question 4 that it has at least renewable contract spanning 25 years. 36

Lastly with regards to UOG, D.04-12-048 dicta and COL also suggest that stranded cost recovery is limited to 10-years, yet it seems to the CCA parties that in practice stranded costs

32 D.04-12-048 at 61, 63, and COL 16.
33 D.04-12-048 at OP 10.
34 See PG&E’s Response to MCE Data Request 003 Question 4 (included within Appendix A of this document.)
35 D.04-12-048 at 63 (“With regard to the long-term contracts for renewable generation called for by the legislature, we have previously authorized the utilities to enter into contracts with terms of up to 20 years order in order to encourage development of these resources.”)
36 See PG&E’s Response to MCE Data Request 003 Question 4 (included within Appendix A of this document.)
-associated with UOG resources are spanning longer than 10-years. As such the CCA Parties implore for the Commission to clearly define either prior to or at the March 8 workshop what the present limitations for stranded cost recovery are for conventional, renewable, and UOG resources.

In addition to the significant uncertainty regarding the stranded cost recovery duration limits as authorized by the Commission, resource online dates vary tremendously as well. Due to both of these factors the resulting duration of cost recovery assigned to each specific vintage of departing load vary considerably. Based on PG&E’s response to MCE’s discovery it appears that this stranded cost recovery will span more than 30-years duration. Considering that the IOUs’ own long-term procurement planning is limited to 10-years, it is unreasonable for other LSEs to plan their procurement around a sizable fee that lasts three times the length of the IOUs’ procurement planning horizon. The Commission has not significantly revised the duration of stranded cost recovery since D.04-12-048, and as stated above this Decision appears to contradictory itself.

Allowing for excessive stranded cost recovery under the PCIA is problematic for several reasons. First, the uncertain duration of the cost recovery on a per vintage basis is challenging to communicate to CCA customers. Second, it creates an unfair dynamic where non-IOU LSEs are forced to plan around a variable charge over a time horizon that is triple the duration of the IOUs’ long-term planning horizon. Third, the special considerations that allow for the extension of stranded cost recovery beyond the standard up to 10-year limit are no longer valid to spur

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37 D.04-12-048 at 61 and COL 16.
38 See PG&E Response to MCE Data Request 002 Question 1, indicating the PCIA stranded cost recovery period for current CCA customers in certain vintages will run until 2043. This also does not address the vintaging issue already in dispute within this proceeding (included within Appendix A of this document.)
renewable energy development and are no longer appropriate in light of the present maturity of the renewable electricity market.

PROPOSED SOLUTIONS:

_i. Solution: Clarify Present Commission Policies on Stranded Cost Recovery_

First off, the stranded cost recovery policy put forth in D.04-12-048 is self-contradictory and vague and must be clarified by the Commission prior to or at the March 8 workshop so that all engaging parties will have a common understanding of what present Commission policy on stranded cost recovery is for all three types of resources that factor into the PCIA calculation: conventional, renewable, and UOG. Such clarifications will likely help to both avoid and resolve disputes between the IOUs and non-IOU LSEs due to this contradiction and vagueness.

_ii. Solution: Limit Stranded Cost Recovery to 10 Years for All Resource Types_

Second, when the Commission determined in D.04-12-048 that it was appropriate to permit the stranded cost recovery for renewable resources via the PCIA for the life of the contract, the RPS mandate was a new creation and the renewable market was nascent. The Commission allowed life of contract stranded cost recovery because the Commission had “previously authorized the utilities to enter into contracts with terms of up to 20 years order in order to encourage development of these resources.” Supra

The period for special treatment of renewable resources contracted for or built by the IOUs has come to a close with prices for these resources approaching prices for conventional power. For example, in January the Palo Alto City Council reviewed and approved a long-term contract for the purchase of renewable energy (solar photovoltaic) at a price of $36.76 per MWh. (https://www.cityofpaloalto.org/civicax/filebank/documents/50532)

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39 D.04-12-048 at 63.
40 For example, in January the Palo Alto City Council reviewed and approved a long-term contract for the purchase of renewable energy (solar photovoltaic) at a price of $36.76 per MWh. (https://www.cityofpaloalto.org/civicax/filebank/documents/50532)
stranded cost recovery for any new contracted or UOG renewable resources to the same “either the life of the contract or 10 years, whichever is less” policy limit that conventional resources are already limited to. This is reasonable and fair. Furthermore, this will significantly reduce the duration and uncertainty surrounding the duration of stranded cost recovery for future vintages of departing load.

5. LIMIT PCIA VOLATILITY AND UNCERTAINTY

The current PCIA methodology allows for too much volatility in the annual adjustment to the PCIA rate. As recently observed in the 2016 PG&E ERRA proceeding, the PCIA rate has the potential to shift dramatically from one year into the next.41 As noted above, the 2016 PCIA rate for residential customers with a 2012 vintage nearly doubled relative the 2015 rate (95% increase). Such a tremendous change in a rate over a single year is unreasonable and puts non-IOU LSEs and their customers in an unfair circumstance where there is very little warning of the pending dramatic rate change.

PROPOSED SOLUTION:

1. Solution: Revise the MPB to Consider 5-Years of Natural Gas Prices

The CCA Parties believe a relatively simple way to dampen fluctuations in the PCIA annual rate adjustment would be to change the natural gas input price used to determine the MPB annually from a single year spot-market natural gas price to a multi-year average natural gas price. The natural gas price should be a 5-year average either based on a 5-year forward pricing curve (i.e. the average of the gas prices for the present year and four years beyond) or through an

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41 See MCE’s filings within A.15-06-001.
averaging to two prior years of historic gas prices with a 3-year forward pricing curve (i.e. the average of the gas prices for the present year with the two years prior and the two years beyond). This will dampen the sensitivity of the MPB calculation to large swings in the natural gas market from year to year. The CCA Parties believe this is a more reasonable approach because the IOUs are not required to sell excess power in the spot market, and instead have the option to sell off any excess above-market electricity through multi-year forward transactions.

6. DEVELOP ALTERNATIVES TO THE VOLATILE YEAR-BY-YEAR PCIA

Presently there is only one mechanism through which CCA customers and other types of departing load can repay their share of the utilities’ unavoidable above-market stranded costs, a single, volatile and annually readjusted volumetric rate that varies somewhat with each vintage of departing load: the PCIA. The CCA Parties believe it is unreasonable and unjust the restrict non-IOU LSEs and their customers to repay these costs through only this one mechanism.

The PCIA calculation process is not transparent. This is compounded by the frequency of the rate change combined with the compressed procedural timeline for considering such rate changes. Therefore, this single annual rate is very challenging to plan around and explain to customers, elected officials and local community members. The non-IOU LSEs should be presented with multiple options—or a Menu of Options—for how their customers will be able to repay their share of unavoidable above-market stranded costs. CCAs and ESPs procure with distinctly different priorities (longer-term procurement vs. shorter-term procurement). CCAs and ESPs also cater to very different types of customers. As such it makes sense to allow for each non-IOU LSE to have options for differing mechanisms by which their customers will repay the unavoidable above-market stranded costs, as certain mechanisms may better fit the customer types and procurement practices of each distinct non-IOU LSE.
PROPOSED SOLUTION:

i. Solution: The Commission Should Provide a Menu of Options for Repayment

The PCIA could be repaid simply through an up-front fixed valuation. This “lump sum” approach has been utilized for municipal departing load under various bilateral agreements with the IOUs.\(^4\) In fact by negotiating and fixing the PCIA repayment responsibility for a specific vintage of customers served by a specific non-IOU LSE in an upfront manner, this would provide the non-IOU LSE with greater certainty and clearer communication to its customer base. The non-IOU LSE could then decide whether it would prefer to: (i) repay this upfront fixed valuation to the IOU in a lump-sum manner and then bear the responsibility of recovering these costs from its customer-base as it feels is appropriate; or (ii) work with the IOU to establish a balancing account for this fixed valuation and amortize the repayment of these costs through a fixed rate over a definite period of time (e.g. a fixed volumetric charge across all customer classes in that vintage of departing load applied to customers’ bills over a 10 year period).

To determine this fixed valuation for a particular vintage of departing load, the IOU and non-IOU LSE would have to negotiate and agree to certain forward cost curves for renewable electricity, capacity, and conventional electricity products. In the end these projected costs could be higher or lower than actual costs, and the non-IOU LSE and its customers would bear that risk in exchange for certainty over their PCIA cost exposure. The CCA Parties envision this negotiation process would occur via a formal settlement process in accordance with Commission Rule 12. The fixed valuation for this particular segment of departing load, along with the fixed

\(^4\) For example, Non-bypassable charge agreements were commended by the Commission in Resolution E-3999 as a possible way by which departing load charges could be fully and finally addressed on a lump sum basis. (See Resolution E-3999 at 44.) As a result, PG&E and SCE entered into numerous non-bypassable charge agreements. (See, e.g., D.10-11-011 at 15. See also D.09-08-015.)
rate of repayment and the duration of the cost recovery if applicable, would be determined by the relevant IOU and non-IOU LSE(s) through this settlement negotiation to then be presented to the Commission for approval through an appropriate proceeding venue.

C. **QUESTION 3: How should the CPUC address the potential departure from bundled service of a very large load, such as the City of San Diego or County of Los Angeles? Would transferring contractual responsibility from an IOU to a CCA be an option?**

Before any sort of special treatment should be determined by the Commission for “very large” load departures, the Commission and parties must first establish a clear understanding with clear criterion for what is considered “a very large load.” Even if all recommended revisions presented in response to question 2 are adopted, the PCIA would still be able to function properly for all types of departing load regardless of the size of the departure. The CCA Parties suspect the complexities of dealing with departing load depend more upon the IOUs’ abilities to forecast and plan for such large load departures, than it depends on the mechanism for recouping costs that the IOU has already committed to. With that said, the CCA Parties largely defer to IOUs, Commission staff, and the representatives of the communities considering departing to form or join CCAs in a “very large load” manner to determine these circumstances the necessary special treatment.

The Commission staff may have difficulty addressing all of the potential issues raised by interested parties in response to these questions within a single workshop. As such, the CCA Parties recommend the discussion on this matter should be limited in the first workshop to reach a common understanding with clear criterion of what is considered “a very large load.” The Commission could then address in a subsequent workshop what special treatment (such as potential transfer of contractual responsibilities) should be considered in instances where “a very large load” departure occurs.
As a final note, this is not the first time that the Commission has considered the issue of “large” in the context of departing load, and the Commission’s past consideration of this issue may prove instructive in this context. In D.08-09-012, among other things, the Commission defined and applied departing load principles to so-called “large municipalizations.” Importantly, as a general rule the Commission held that historical trends should be used to determine the amount of future departing load that will occur. In the context of CCA programs, this means that the IOUs should take note of and plan for CCA departing load in a scale comparable to that which has occurred in recent years. The Commission went on to define “large municipalization” as follows:

While there is no precise measure of what constitutes a “large municipalization,” in the context of this decision, we are defining “large municipalization” as any portion of an IOU’s service territory that has been taken control of or annexed by a POU where the amount of load departing the IOUs’ service territories due to the municipalization is of such a large magnitude that it cannot reasonably be assumed to have been reflected as part of the historical MDL trends used in developing the adopted LTPP load forecasts.

As a procedural matter, the Commission determined that “[i]mposition of new generation NBCs on customers departing due to large municipalizations shall be accomplished through a separate application filed by the affected IOU. Customers’ NBC cost responsibility shall be determined through a fair share analysis based on the record of that proceeding. The IOU has the burden to show the departures are within the definition of a large municipalization, especially as it relates to how the large municipalization is or is not reflected in the adopted LTPP load forecasts.”

43 D.08-09-012 at 27.
44 D.08-09-012 at 27.
45 D.-08-09-012 at 28-29.
D. QUESTION 4: Should Direct Access (DA) customers and Community Choice Aggregator (CCA) customers be treated differently vis-à-vis the PCIA? If so, why and how?

As part of its response to Question 2, the CCA Parties advocate for the Commission to allow for a “Menu of Options” for repayment of the PCIA. The CCA Parties believe this menu of options should be equally available to all entities serving departing load. While there are certain differences in the customer base and procurement practices of CCAs and DA, the CCA Parties do not believe that any of the solutions previously presented in Question 2 are uniquely suited for CCAs.

As noted above, the nature of departing load is evolving and changing. In addition to ratepayers served by CCA and DA, departing load that is subjected to the PCIA includes participants in the Green Tariff programs and CGDL. The Commission should strive for PCIA reform that is both fair to all forms of departing load and flexible enough to enable LSEs to plan around the PCIA and effectively communicate the realities of the PCIA to their customers.

In its consideration of reforming PCIA, the Commission should consider whether the load has departed to procure cleaner electricity than is provided through the IOUs’ bundled portfolio. In these cases where load departs from bundled service to consume cleaner electricity, this departing load behavior is voluntarily accelerating the State’s abilities to achieve is Climate Change goals. The CCA Parties believe such behavior should be supported, not restricted. Presently the PCIA serves a barrier that inhibits all forms of departing load, regardless of whether the motives for the load departure do or do not align with the State’s policy objectives.

For example, how customer vintages are determined and assigned under the PCIA for CCA and DA customers has already been presented within the record of this proceeding.
This is contrary to the Commission’s historical application of departing load charges. In short, the Commission has balanced and harmonized the “fair share” cost responsibility requirements contained in AB 117 with other statutory provisions. For example, “despite apparent contrary language in AB 117, [the Commission] harmonized Public Utilities Code Section 366.2(d) with Public Utilities Code Section 353.2(b) to permit an exception for the payment of CRS for load involving ultra-clean and low-emission distributed generation.”47

E. **QUESTION 5: Can transparency regarding the calculation of the PCIA be increased while protecting valid interests in keeping certain information confidential?**

As discussed in detail within the response to Question 2, the CCA Parties believe there is substantial need for improving the transparency of information used to calculate the PCIA, especially in the context of CCAs. The existing confidentiality process bars any meaningful review and evaluation of market sensitive information by CCAs, and makes the “meaningful public participation and open decisionmaking” mandated in Senate Bill 1488 (2004) difficult to accomplish. In the context of the PCIA, the restrictions on the review of information by market participants preclude any evaluation of whether the calculations performed by the IOU were performed accurately. CCAs are therefore unable to determine where the PCIA cost recovery requirement is presently and what changes will be made in the future.

47 D.03-04-030. D.03-04-030 is replete with policy-based explanations as to why cost responsibility charges should not apply to various distributed generation resources. The following is summary of these explanations: “On the basis of the policy preferences already articulated by the Legislature, as codified in recently enacted statutes, and by this Commission, however, we believe that there is sufficient policy basis to believe that customer generation confers a positive public benefit. Therefore, and consistent with these legislative policy directives, and in support of our policy preferences, we believe that we should apply CRS components differentially….” (D.03-04-030 at 45.)
Once deemed a market participant, a CCA is heavily restricted in its access to information. As explained in D.11-07-028, market participants can only access market sensitive information through the use of “reviewing representatives” who review the information under a non-disclosure agreement and retain the documents with strict confidentiality protections.\textsuperscript{48} Among other things, a reviewing representative cannot be an employee of the market participant and a reviewing representative also cannot be engaged in electricity transactions at wholesale, bidding on power plants, or electricity marketing services. This restriction effectively screens out many qualified, independent consultants with industry expertise who are capable of readily understanding and reviewing the information provided. Even if a reviewing representative of a CCA did find important information pertinent to the purpose of the review, this information is under strict confidentiality protections and thus the findings of the review cannot even be disclosed to the CCA.

As discussed in Question 2 above, the CCA Parties propose several solutions to make information available. To the extent the solutions cannot be implemented in this proceeding, we recommend that the Commission include these modifications for discussion as part of the Commission’s present efforts to improve access to information in Rulemaking 14-11-010.

\textsuperscript{48} See D.06-06-066.
IV. CONCLUSION

The CCA Parties thank Administrative Law Judge Tsen, Commissioner Florio and Energy Division staff for their attention to the matters discussed herein.

Respectfully submitted,

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ON BEHALF OF
MARIN CLEAN ENERGY
AND CITY OF LANCASTER

February 16, 2016
APPENDIX A:

ATTACHMENT 1: Chapter 9 of PG&E’s Opening Testimony for its 2015 ERRA Application

ATTACHMENT 2: Commission Resolution E-4475 – Exhibit A

ATTACHMENT 3: PG&E Response to MCE Data Request 002 – Question 1

ATTACHMENT 4: PG&E Response to MCE Data Request 003 – Question 4
ATTACHMENT 1:

Chapter 9 of PG&E’s Opening Testimony for its 2015 ERRA Application
PACIFIC GAS AND ELECTRIC COMPANY

PREPARED TESTIMONY

2015 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST

PUBLIC VERSION
CHAPTER 9

2015 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST

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A. Introduction

This chapter discusses the calculation methodologies used to develop the procurement-related Non-Bypassable Charges (NBC) forecast in the Energy Resource Recovery Account (ERRA) Forecast Proceeding. Specifically, this chapter presents the derivation of revenue requirements for the 2015 Ongoing Competition Transition Charge (Ongoing CTC), Indifference Amount and related Power Charge Indifference Adjustment (PCIA), and the Cost Allocation Mechanism (CAM).

B. Commission-Adopted Market Benchmark

1. Background

The Market Price Benchmark (MPB) is used to calculate both the Ongoing CTC and PCIA revenue requirements. The difference between the average cost of the portfolio of resources, such as the total portfolio used in the PCIA calculation or the Ongoing CTC portfolio costs, and the market price benchmark reflects stranded or above market costs associated with the procurement portfolio. Thus, the revenue requirement is determined by comparing the ongoing CTC or total portfolio costs to an equivalent market-based portfolio, which is derived by multiplying the MPB value times the portfolio’s forecasted generation in megawatt-hours (MWh). The resulting difference between the portfolio cost forecast and the market-based value for that portfolio forms the basis for the ongoing CTC or total portfolio indifference revenue requirements.

The MPB calculation starts with a foundation that was originally adopted in Decision 06-07-030, as modified by Decision 07-01-025. Specifically, the foundational portion of the benchmark calculation remains unchanged in that a portion of the benchmark using conventional gas-fired generation resources is calculated annually by the Energy Division (ED) based on the procedure described in Appendix 1 to Decision 06-07-030, as modified by
Decision 07-01-030 (Ordering Paragraph (OP) 2). That decision requires ED to:

- Collect daily forward price quotes from October 1 through October 31 for 12 months of on-peak (6 days × 16 hours/day) and off-peak (6 days × 8 hours/day; 1 day × 24 hours/day) power delivered at North of Path 15 (NP-15), as published in *Platts-ICE Forward Curve – Electricity* for NP-15.

- Average the daily quotes to get an annual on-peak forward price and an annual off-peak forward price.

As discussed below, the subsequent portions of the MPB calculation as originally described in Decision 06-07-030 were modified based on the directives in Decision 11-12-018, which were implemented, in part, in Resolution E-4475.

2. Total Portfolio Indifference and Benchmark Calculation Methodologies

In December 2011, the California Public Utilities Commission (CPUC or Commission) issued Decision 11-12-018, adopting revisions to the calculation methodologies for the total portfolio indifference calculation and to the MPB. The most significant revision was to the MPB calculation, which now includes a green adder that accounts for Renewables Portfolio Standard (RPS) eligible resources in the generation portfolio included in the indifference or Ongoing CTC calculations. The decision also included a modification to the capacity adder, which is now based in part on the composition of the resources in the portfolio.

The PCIA revenue requirement results presented in this chapter are consistent with Decision 11-12-018 and Resolution E-4475 directives with the exception that the updates for the green adder cannot be fully implemented until the November update, when data for all three Investor-Owned Utilities (IOU) becomes available. Both calculations and the new modifications are discussed in more detail below.

3. Resolution E-4475

Resolution E-4475, approved May 10, 2012, implements, in part, the method adopted in Decision 11-12-018 to account for the market value of RPS-compliance resources in the NBC applicable to departing load.
A description of the process by which the revised MPB will be calculated and updated annually, was memorialized in Exhibit A of Resolution E-4475. This resolution approved the Green benchmark, based on data submitted by the IOUs in compliance with Decision 11-12-018. The Green benchmark will be incorporated as a component into the final MPB used to calculate the relevant NBC on a vintaged basis. Exhibit A to Resolution E-4475 provides a detailed formula for the MPB calculation, which Pacific Gas and Electric Company (PG&E) includes as Attachment 9A to this chapter. This attachment provides the MPB components and the calculation methodology and process. The formula and process described in Resolution E-4475 at page 8 and the associated Exhibit A (Attachment 9A to this chapter) provide that:

- To incorporate the RPS adder into the MPB, on October 1 of each year, each utility files an advice letter, pursuant to OP 5 of Decision 11-12-018, to update their data, since, per OP 5, “The applicable percentage weightings [32 percent DOE Data and 68 percent utility data] are subject to relevant updated data in subsequent years.” These advice letters may be designated as Tier 1, and any confidential data shall be protected from public disclosure, as provided in OP 4 of Decision 11-12-018.

- For receipt by early November of each year, ED purchases from Platt’s (or another appropriate source) daily trading prices for the calendar month of October both for on-peak and off-peak periods for both North and South of Path 15. Using this data together with the shaping factors adopted in Decision 11-12-018, ED performs the MPB calculation as adopted in Decision 06-07-030 and compares its results with each utility’s own calculation.

- Using the confidential data provided by the utilities in their October 1 advice letters on their RPS-compliant resources, the ED calculates the average energy cost of the utilities’ RPS-compliant resources to incorporate into the MPB as adopted in Decision 11-12-018.

- Each utility then uses ED’s results in its procurement forecast to compute specific MPBs by vintage and the applicable departing load cost responsibility surcharges.
4. 2015 Market Price Benchmark

The 2015 MPB used in this testimony was calculated based on the methodology described above. Due to the timing of PG&E’s application filing, the MPB is an initial estimate of the 2015 result and relies on April forward market data, rather than October data as described in the relevant decisions. As a result, the forecast as presented in this testimony will be subject to an update, consistent with PG&E’s November update of forward market prices and procurement costs, as well as the new requirement to submit a compliance advice letter on October 1 to update renewable data used to support the statewide Green benchmark results for the forecast year.

The initial estimated value, as presented in this testimony, utilizes the most recently approved Green benchmark price data for 2014 as a proxy for 2015. This result is combined with the peak and off-peak forward price data using April data, and the revised calculation methodology, as described below:

- Collect daily forward price quotes from April 1 through April 30, 2014, for 12 months of on-peak (6 days × 16 hours/day) and off-peak (6 days × 8 hours/day; 1 day × 24 hours/day) power delivered at NP-15 in 2014, as published in Platts-ICE Forward Curve – Electricity for NP-15.
- Average the daily quotes to get an annual on-peak forward price and an annual off-peak forward price.
- Determine a weighted average forward power cost for 2015 by multiplying the average on-peak and off-peak price times the weighting factors adopted in Decision 11-12-018, which are based on the most recent publicly available peak and off-peak bundled load weighting.
- Add a resource adequacy (RA)/capacity cost to the forward price based on the net qualifying capacity value in the portfolio, which is derived as:
  - \textbf{Capacity (CAP) ADDER} = \left\{ \frac{\text{Sum of Net qualifying Capacity for all resources in the Utility Retained Generation (URG) Total Portfolio for PCIA Vintage year } v \times \text{CAP VALUE}}{\text{forecast of the sum of MWh supplied by URG Total Portfolio for PCIA Vintage year } v} \right\} ; \text{where}
- **CAP VALUE** = the going forward cost (sum of insurance, *ad valorem* and fixed operations and maintenance costs) of a combustion turbine as determined per the most recent California Energy Commission’s *Comparative Costs of California Central Station Electricity Generation Report* for a small simple cycle merchant plant.

- Add a line loss factor. The line loss factor accounts for delivery losses from NP-15 to load centers and is applied to the sum of the forward price cost, the weighted average green benchmark results, and the capacity adder to arrive at the final MPB value for each vintage portfolio. Decision 07-01-030 set the line loss factor at 6.0 percent for PG&E which remained unchanged in Decision 11-12-018, as described in Resolution E-4475.

5. **Final Market Price Benchmark Calculation**

As described in Attachment 9A (Exhibit A of Resolution E-4475), ED calculates the “BROWN and GREEN elements” in the MPB formula, based on inputs provided by each IOU in its respective October Compliance Advice Letter. Once ED provides these elements, the IOUs calculate the MPB for each vintage, based upon the “GREEN and BROWN values,” the “CAP Value” above, and provide the calculations to ED for verification. PG&E uses ED’s updated inputs in the November Update annual forecast. As described above, for this testimony, PG&E is relying on the 2014 GREEN element as a proxy for 2015 and April forward price data, both of which will be updated in PG&E’s November update testimony. The resulting estimate for the vintage MPBs are presented in Table 9-1.

C. **Non-Bypassable Charges – Currently Effective Calculation Methodology**

1. **Ongoing Competition Transition Charge Forecast Revenue Requirement**

The purpose of Ongoing CTC is to recover uneconomic costs resulting from California’s electric industry restructuring from all consumers responsible for those costs. The Ongoing CTC represents above-market costs associated with eligible Qualifying Facility (QF) contracts and Power Purchase Agreement (PPA) restructuring costs, and other costs as
authorized by the Commission. The Ongoing CTC is to be collected from all
existing and future consumers as of December 20, 1995, for all power
purchase contract costs included in CPUC rates as of that date. The
calculation of Ongoing CTC follows the same “statutory method” presented
in each of PG&E’s ERRA applications since 2004. The statutory method
refers to Pub. Util. Code Section 367(a)(1)-(6), which specifies the costs to
be included in the above-market calculation. Use of the statutory method
was clarified by the Commission in Decision 05-12-045.

PG&E’s pre-1996 contracts include agreements with QFs, Irrigation
Districts and Water Agencies (ID&WA), the Metropolitan Water Agency, and
the City and County of San Francisco. Most, but not all, of PG&E’s QF
contracts are CTC-eligible. Because energy payments to QFs are in
proportion to natural gas prices, PG&E executes financial hedges against
these costs as discussed in Chapter 8, “Hedging and Collateral Costs.”
The costs or benefits of these hedges are considered a part of QF purchase
costs and thus are included in the above-market calculation.

The above-market cost for Ongoing CTC-eligible contracts is the
difference between their total cost and the cost if the same volume of
electricity MWh were purchased at the MPB $/MWh. The MPB is discussed
in Section B. Costs associated with CPUC-approved QF contract
restructurings are added directly to the above-market cost to produce the
total Ongoing CTC cost. PG&E presents its 2015 Ongoing CTC revenue
requirement calculation in Table 9-2.

Ongoing CTC-eligible contract costs are presented on lines 1 through 7,
including line losses. Line 8 shows the market value of these resources.
Line 9 reflects the difference between line 7 and line 8, which is the
above-market portion of PG&E’s legacy QF and ID&WA contracts. The
ongoing CTC revenue requirement of $83.2 million is presented on line 14

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3 Decision 05-12-045, in PG&E’s 2006 ERRA and Ongoing CTC revenue requirement proceeding, explicitly adopted the “statutory” method for calculating the Ongoing CTC, see OP 6, which in part states, “Ongoing CTC shall be calculated in accordance with the statutory method described in the body of this Order… .”
and includes franchise fees and uncollectibles (FF&U) and the expected 
year-end 2014 MTCBA balance.

2. Total Portfolio Indifference and the Power Charge Indifference Amount

This testimony presents PG&E’s indifference calculations for forecast 
year 2015 for non-exempt Direct Access (DA) and Departing Load (DL) as 
defined in Decisions 06-07-030, 07-01-025, 08-09-012 and 11-12-018, and 
Resolution E-4475.

Decision 06-07-030 adopted an indifference calculation specifically to 
recover stranded costs associated with the California Department of Water 
Resources (CDWR) contracts. The indifference amount was determined by 
comparing the MPB value, as prescribed in Appendix 1 of that decision, with 
the average cost of the utilities’ total portfolio, including both utility retained 
generation power and allocated CDWR power costs, to determine the level 
of the indifference charge. As described above, the MPB described in this 
decision has been modified by Decisions 11-12-018, implemented through 
Resolution E-4475.

In Decision 04-12-048, the Commission provided for stranded cost 
recovery in the form of a NBC to be paid by customers when they elect DA 
service, depart to be served by a Community Choice Aggregator (CCA), or 
elect another DL option. The NBC would be determined based on the timing 
of the customers’ departure (i.e., customer vintage) and the date of the new 
generation resource commitment. Decision 08-09-012 approved the final 
calculation methodology associated with the new generation resource 
commitments authorized in Decision 04-12-048 which was a modified 
version of the indifference calculation approved in Decision 06-07-030. 
The Decision 04-12-048 PCIA would be applicable to departing customers 
not exempt from the NBC associated with the new generation resources as 
defined in the September 2008 decision. The modified indifference 
calculation includes the addition of new generation resource to each utility’s 
total portfolio of resources, by vintage.
3. Calculation of the Indifference Amounts

a. Decision 06-07-030 Total Portfolio Indifference

The Decision 06-07-030 PCIA includes generation costs for resources in PG&E’s portfolio prior to 2001/2002, often referred to in Decision 06-07-030 as “old-world” generation resources. More specifically, this calculation was established to collect stranded costs associated with the CDWR power contracts. PG&E has one remaining CDWR contract which is eligible for stranded cost recovery pursuant to Decision 06-07-030 and this contract will expire in September 2015. As a result, the PCIA associated with the CDWR power charge will end or be set to zero effective October 1, 2015.

The indifference calculation includes PG&E’s total portfolio generation cost and gigawatt-hour (GWh) of generation, as described in Decision 06-07-030 and is the sum of:

1) PG&E’s estimated CDWR Power Charge revenue requirement.
2) PG&E’s old world generation revenue requirement.

The average cost of PG&E’s total portfolio is compared to the market value to determine the level of the indifference for this portfolio of contracts. The MPB value is derived by multiplying the Pre-2009 MPB, discussed in Section B, by the total portfolio generation in GWh.

Table 9-3 shows the 2015 indifference results for PG&E’s total portfolio Decision 06-07-030 indifference calculation, on line 6.

The indifference result on line 6 reflects whether the portfolio costs are above or below market. Below market costs are negative and would be tracked to offset a future year’s above market results. Above market costs are positive and would be combined with negative results from prior years to determine a cumulative Indifference amount.4

For 2015, the above market result is shown on line 6 and is combined with the negative results from prior years, shown on line 7. The cumulative indifference amount for 2015 is shown on line 8.

The equation to determine the PCIA revenue requirement is:

4 Negative results will be tracked in the Negative Indifference Amount Memorandum Account.
\[
\text{Indifference} = Ongoing \text{ CTC} + PCIA
\]

or

\[
PCIA = \text{Indifference} - Ongoing \text{ CTC}
\]

If the cumulative indifference is less than or equal to zero, in the equation, Indifference is set to zero and solving for PCIA, the equation becomes:

\[
PCIA = -Ongoing \text{ CTC}
\]

The indifference amount used to set the 2015 PCIA rate is presented on line 12 of Table 9-3.

b. Decision 04-12-048 Total Portfolio Indifference Calculation

The total portfolio indifference calculation for non-exempt departing customers that departed during or after 2009 includes the “old-world” generation costs discussed above as well as new generation resource commitments as authorized in Decision 04-12-048. In addition to including new generation resource commitments, the total portfolio indifference calculation for this group of departing customers is vintaged such that new generation resource commitments are included in the total portfolio calculation based on the year the commitment was made.

The 2015 forecast indifference amount includes PG&E’s total portfolio generation cost and GWh of generation, by vintage, as the sum of:

1) PG&E’s estimated CDWR Power Charge revenue requirement.

2) PG&E’s forecast for its old world resources.

3) PG&E’s post-2002 resource commitments, as applicable, by vintage.

The average cost of PG&E’s total portfolio, by vintage, is compared to the MPB value to determine the level of the indifference for each vintaged portfolio. The MPB values for each vintage portfolio are derived by multiplying the vintage portfolio’s MPB as described in Section B, by the portfolio’s generation in GWh, shown on line 2.

Similar to the Decision 06-07-030 calculations, the indifference result on line 6 reflects whether the portfolio costs are above or below market. Below market costs are negative and would be tracked to offset
a future year’s above market results. Above market costs are positive and would be combined with negative results from prior years to determine a cumulative Indifference amount.

For 2015, the above market result is shown on line 6. For Vintages 2009 through 2015, there are no negative results from prior years, and thus, the cumulative indifference amount for 2015 shown on line 6 is repeated on line 8.

The equation to determine the PCIA revenue requirement is:

\[
\text{Indifference} = \text{Ongoing CTC} + \text{PCIA}
\]

or

\[
\text{PCIA} = \text{Indifference} - \text{Ongoing CTC}
\]

The indifference amount used to set the 2015 Vintaged PCIA rate is presented on line 12 of Table 9-3.

c. Power Charge Indifference Amount Revenue Requirement

PG&E calculates the PCIA revenue requirement for non-exempt departing customers by utilizing the PCIA rate which is developed based on system-level power charge indifference revenue requirements shown on Table 9-3, line 12. Specifically, the PCIA rates are multiplied by the non-exempt DL to generate a forecast for the respective Decision 06-07-030 or Decision 04-12-048 PCIA revenue requirements. The Decision 06-07-030 PCIA revenue requirement is negative and reflects a credit of $2.9 million to non-exempt load that departed prior to 2009. This departing load credit will be a debit (cost) to bundled customers in ERRA. The Decision 04-12-048 PCIA revenue requirement is positive and reflects a cost of $50.2 million to non-exempt departing customers that depart bundled service between 2009 and 2015. This departing load cost will be a credit to bundled customers in ERRA.

4. Cost Allocation Mechanism

The CAM charge was initially authorized in Decision 06-07-029 and the methodology by which it was to be calculated was determined in Decision 07-09-044, which approved specific guidelines to be used to develop the CAM revenue requirement and resulting rate and provide for a
true-up of this rate to actual costs. Subsequently, a CAM approach was adopted in Decision 10-12-035 for certain contracts arising from the Qualifying Facility and Combined Heat and Power (QF/CHP) Settlement approved in that decision. CAM treatment was also approved for the Marsh Landing PPA approved in Decision 10-07-045.

Under the CAM approach, certain costs and benefits are allocated among all load serving entities in the IOU’s service territory. The allocated benefits include RA benefits. The load serving entities’ customers receiving the RA benefit pay the net cost of this capacity, determined as a net of the total cost of the contract minus the energy revenues associated with dispatch of the contract.

The CAM charge was first included in forecast year 2012, as a result of the QF/CHP Settlement. For the 2015 Forecast, the CAM includes new CHP generation authorized under the QF/CHP Settlement and the Marsh Landing PPA, which was authorized for CAM treatment in Decision 10-07-045.

Chapter 3 of PG&E’s testimony has costs related to the Marsh Landing PPA and Chapters 3 and 5 of PG&E’s testimony have forecasts related to actual and expected CHP contracts costs and MWh that are eligible for recovery under the terms of the QF/CHP Settlement and OP 3 of Decision 10-12-035.

The CAM revenue requirement presented in this chapter adheres to the guidelines approved in Decision 07-09-044, which were included as Appendix A to that decision. Specifically, Appendix A included a “Joint Parties’ Proposal” that articulated a calculation methodology to determine the market value of the resource. The basic idea is that the cost of the resource minus the value of the energy and ancillary services results in a net capacity cost that is then allocated to all benefiting customers.

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5 Decision 14-02-040, OP 3, in Rulemaking 12-03-014, eliminated the Energy Auction originally approved in Decision 07-09-044 as the primary mechanism to determine market revenues associated with reliability resources. OP 3 states, “Energy auctions shall no longer be used to net capacity costs for facilities subject to the Cost Allocation Mechanism. Instead Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall use the mechanism adopted in Decision 07-09-044, known as the “Joint Parties’ Proposal,” to set the residual capacity costs that would be allocated to benefitting customers.
Attachment 9B to this chapter reproduces Section IX of Appendix A to Decision 07-09-044, which details the “Implementation Joint Parties’ Proposal.”

Generally, the methodology provides for developing a forecast of the relevant contract costs, then determining the value that resource’s generation would have in the California Independent System Operator (CAISO) day-ahead market. The net results of the individual contracts are summed, and the total determines the net capacity costs that would be allocated to bundled, DA, CCA, and other DL customers.

This forecast of the net capacity costs is then used to set the CAM rate, which is discussed in Chapter 11. The forecast will be trued-up to actual costs by recording actual contract costs and the value of the generation based on the CAISO hourly day-ahead nodal price for the PPA’s “injection point.” The balance in the balancing account would then be amortized at the end of the year and incorporated into next year’s forecast rate.

The CAM results are presented in Table 9-4 and result in a revenue requirement of $219.5 million.

D. Conclusion

PG&E requests that the Commission adopt PG&E’s NBC forecast revenue requirements as follows:

1) Ongoing CTC revenue requirement of $83.2 million, presented in Table 9-2.

2) Decision 06-07-030 PCIA 2015 revenue requirement credit of $2.9 million associated with CDWR stranded costs, as described in Section C.3.a above.

3) Decision 04-12-048 PCIA 2015 revenue requirement forecast of $50.2 million associated new generation resources as described in Section C.3.b above.

4) CAM revenue requirement of $219.5 million presented in Table 9-4 and described in Section C.4.

PG&E requests that the Ongoing CTC and PCIA revenue requirements be updated in the November update, consistent with the scheduled adopted for the proceeding, and the balancing account balances will be updated one last time in December for implementation through the Annual Electric True-Up on or after January 1, 2015.
### TABLE 9-1
**PACIFIC GAS AND ELECTRIC COMPANY**
**2015 VINTAGED MARKET PRICE BENCHMARK**

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<td></td>
<td></td>
<td>1.060</td>
<td>1.060</td>
<td>1.060</td>
<td>1.060</td>
<td>1.060</td>
<td>1.060</td>
<td>1.060</td>
</tr>
<tr>
<td>20</td>
<td>MPB with Renewable Premium, by Vintage</td>
<td></td>
<td>$79.09</td>
<td>$66.23</td>
<td></td>
<td></td>
<td></td>
<td>$78.02</td>
<td>$81.77</td>
<td>$82.71</td>
<td>$83.29</td>
<td>$84.85</td>
<td>$84.86</td>
<td>$84.86</td>
</tr>
</tbody>
</table>

**Note:** Totals may not add due to rounding.
# TABLE 9-2
**PACIFIC GAS AND ELECTRIC COMPANY**
**2015 ONGOING CTC FORECAST REVENUE REQUIREMENT**

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>(MWh)</th>
<th>(GWh)</th>
<th>($000)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Qualifying Facilities (CTC-Eligible)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Gas Hedging for QF Short-Run Avoided Cost Payments</td>
<td></td>
<td>28</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Metropolitan Water District</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Irrigation Districts and Water Agencies</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td><strong>Total</strong></td>
<td>7,055</td>
<td></td>
<td><strong>531,934</strong></td>
</tr>
<tr>
<td>6</td>
<td>6% Line Loss</td>
<td></td>
<td>(423)</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Net Pre-1996 Contracts (Lines 5-6)</td>
<td>6,632</td>
<td></td>
<td><strong>531,934</strong></td>
</tr>
<tr>
<td>8</td>
<td>Market Benchmark Cost</td>
<td>$79.09</td>
<td>6,632</td>
<td>524,501</td>
</tr>
<tr>
<td>9</td>
<td>Above-Market Costs (Line 7– Line 8)</td>
<td></td>
<td></td>
<td><strong>7,433</strong></td>
</tr>
<tr>
<td>10</td>
<td>Ongoing CTC Costs</td>
<td></td>
<td></td>
<td><strong>7,433</strong></td>
</tr>
<tr>
<td>11</td>
<td>FF&amp;U at 0.01226</td>
<td></td>
<td></td>
<td>91</td>
</tr>
<tr>
<td>12</td>
<td>Ongoing CTC Revenue Requirement</td>
<td></td>
<td></td>
<td>7,525</td>
</tr>
<tr>
<td>13</td>
<td>Year-End 2014 MTCBA Balance (Including FF&amp;U)</td>
<td></td>
<td></td>
<td>75,717</td>
</tr>
<tr>
<td>14</td>
<td>Total 2015 Ongoing CTC Revenue Requirement</td>
<td></td>
<td></td>
<td><strong>83,242</strong></td>
</tr>
</tbody>
</table>

Note: Totals may not add due to rounding.
# TABLE 9-3
## PACIFIC GAS AND ELECTRIC COMPANY
### 2015 INDIFFERENCE CALCULATION

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Total Portfolio Generation at Generator (GWh)</td>
<td>34,327</td>
<td>56,106</td>
<td>59,279</td>
<td>60,716</td>
<td>62,825</td>
<td>62,982</td>
<td>62,984</td>
<td>62,984</td>
</tr>
<tr>
<td>2</td>
<td>Total Portfolio Generation at Customer Meter (Includes Line Losses) (GWh)</td>
<td>32,268</td>
<td>52,739</td>
<td>55,722</td>
<td>57,073</td>
<td>59,055</td>
<td>59,203</td>
<td>59,205</td>
<td>59,205</td>
</tr>
<tr>
<td>3</td>
<td>Total Portfolio Cost ($1,000)</td>
<td>$2,248,778</td>
<td>$4,912,686</td>
<td>$5,398,045</td>
<td>$5,582,400</td>
<td>$5,765,558</td>
<td>$5,829,622</td>
<td>$5,829,841</td>
<td>$5,829,841</td>
</tr>
<tr>
<td>4</td>
<td>Benchmark ($/MWh)</td>
<td>66.23</td>
<td>78.02</td>
<td>81.77</td>
<td>82.71</td>
<td>83.29</td>
<td>84.85</td>
<td>84.86</td>
<td>84.86</td>
</tr>
<tr>
<td>5</td>
<td>Market Cost ($1,000)</td>
<td>2,137,083</td>
<td>4,114,725</td>
<td>4,556,416</td>
<td>4,720,521</td>
<td>4,918,706</td>
<td>5,023,354</td>
<td>5,024,141</td>
<td>5,024,141</td>
</tr>
<tr>
<td>6</td>
<td>Current Year Indifference (Line 3 – Line 5)</td>
<td>$111,694</td>
<td>$797,961</td>
<td>$841,629</td>
<td>$861,879</td>
<td>$846,852</td>
<td>$806,268</td>
<td>$805,700</td>
<td>$805,700</td>
</tr>
<tr>
<td>7</td>
<td>2014 Cumulative Indifference (1,191,206)</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>2015 Cumulative Indifference (1,079,512)</td>
<td>797,961</td>
<td>841,629</td>
<td>861,879</td>
<td>846,852</td>
<td>806,268</td>
<td>805,700</td>
<td>805,700</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>2015 Cumulative Indifference With FF&amp;U</td>
<td>$(1,092,746)</td>
<td>$807,744</td>
<td>$851,947</td>
<td>$872,445</td>
<td>$857,234</td>
<td>$816,153</td>
<td>$815,577</td>
<td>$815,577</td>
</tr>
<tr>
<td>10</td>
<td>Ongoing CTC Cost Revenue Requirement (RRQ)</td>
<td>7,525</td>
<td>7,525</td>
<td>7,525</td>
<td>7,525</td>
<td>7,525</td>
<td>7,525</td>
<td></td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Ongoing CTC End-of-Year (EOY) MTCBA Balance</td>
<td>75,717</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td></td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>PCIA Revenue Requirement for Rate Calculation(a) = Indifference – Ongoing CTC = (Line 9 – (Line 10 + Line 11))</td>
<td>$(83,242)</td>
<td>$800,220</td>
<td>$844,423</td>
<td>$864,921</td>
<td>$849,710</td>
<td>$808,629</td>
<td>$808,053</td>
<td>$808,053</td>
</tr>
</tbody>
</table>

(a) PCIA revenue requirements in Chapter 1 and 10 are imputed based on PCIA rate times non-exempt load.

Note: Totals may not add due to rounding.
<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Costs ($000s)</th>
<th>2015 Total CAM</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Costs</td>
<td>$384,390</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Revenue</td>
<td>(156,324)</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>CAM Results</td>
<td>228,066</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Total CAM Revenue Requirement</td>
<td>230,862</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>New System Generation Balancing Account (NSGBA)</td>
<td></td>
<td>(11,316)</td>
</tr>
<tr>
<td></td>
<td>EOY Balance</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Total CAM RRQ</td>
<td>$219,546</td>
<td></td>
</tr>
</tbody>
</table>

Note: Totals may not add due to rounding.
ATTACHMENT 2:

Commission Resolution E-4475 – Exhibit A
Exhibit A

Proposed Formula to Calculate the Market Price Benchmark per D.11-12-018

Revised MPB for year \( n \) and Vintage Total Portfolio \( v = (1 - \text{RPS}\%_v) \times \text{BROWN} + (\text{RPS}\%_v) \times \text{GREEN} + \text{CAP ADDER}_v \times (\text{LOSSES}) \)

\( n \) = year covered by the calculation, e.g. \( n = 2012 \) for the MPB for 2012.

\( v \) = PCIA vintage year

\( \text{RPS}\% = \) The fraction of RPS compliant electric energy in the URG [Utility Resource Generation] Total Portfolio\(^6\) for PCIA Vintage year \( v \) in year \( n \).

\( \text{BROWN} \) = Weighted average of peak and off-peak forward prices for year \( n \), weighting based on, for each IOU, the IOU bundled load profile data for the most recent year that is publicly available. Peak and off-peak forward prices based on published data for NP15/SP15 as per D.06-07-030. ($/MWh)

\( \text{GREEN} \) = \( 0.68 \times \text{URGgreen} + 0.32 \times (\text{BROWN} + \text{DOEadder}) \)

Where:

\( \text{URGgreen} \) = \( [(\text{Forecasted cost in year } n \text{ of RPS power contracts and IOU-owned projects starting deliveries in year } n \text{ and } n-1) - (\text{NQC}\_7 \text{ of those contracts/projects} \times \text{CAP VALUE})]/(\text{Total forecasted deliveries from those contracts in year } n) \) ($/MWh)

The forecasted cost of all Renewable Energy Credit (REC)-only contracts will also include the cost of energy associated with those REC-only contracts, equal to \( \text{BROWN} \times \text{forecasted deliveries from those REC-only contracts in year } n \).

\( \text{DOEadder} \) = Simple average of the premiums of the renewable programs in states within Western Electricity Coordinating Council (WECC), as identified in the database compiled by the National Renewable Energy Laboratory for the US Department of Energy. If multiple premiums are identified for the same utility and/or program, all shall be included in the average. ($/MWh)

\(^6\) Per D.07-07-030 and D.08-09-012

\(^7\) Net Qualifying Capacity
CAP ADDER = \{\text{Sum of NQC for all resources in the URG Total Portfolio for PCIA Vintage year } v \times \text{CAP VALUE}\}/\text{forecast of the sum of MWh supplied by URG Total Portfolio for PCIA Vintage year } v \}

\text{CAP VALUE} = \text{the going forward cost (sum of insurance, ad valorem and fixed operations and maintenance costs) of a combustion turbine as determined per the most recent California Energy Commission (CEC) Comparative Costs of California Central Station Electricity Generation Report}^8 \text{ for a small simple cycle merchant plant.}

Per Table 4 of 2010 CEC report,

- Insurance: \$9.63 \text{ per kW-year}
- Ad Valorem: \$13.09 \text{ per kW-year}
- Fixed O&M: \$27.45 \text{ per kW-year}
- Total Going Forward Costs (CAP VALUE): \$50.17 \text{ per kW-year}

\text{LOSSES} = \text{Line loss factors per D.07-01-030: PG&E 1.06; SCE 1.053; SDG&E 1.043}

The Energy Division would calculate the \text{BROWN} and \text{GREEN} elements to the formula, based on inputs provided by each IOU. The IOUs would calculate the Market Price Benchmarks for each Vintage, based upon the \text{GREEN} and \text{BROWN} values provided by Energy Division, the \text{CAP VALUE} above, and the RPS percentages, NQCs and energy of each URG Total Portfolio. These calculations would be provided to Energy Division for verification.

---

ATTACHMENT 3:

PG&E Response to MCE Data Request 002 – Question 1
SUBJECT: POWER CHARGE INDIFFERENCE ADJUSTMENT (PCIA)

QUESTION 1

For each PCIA customer vintage, beginning with 2010 and continuing through 2016, please provide the expected dates on which PG&E will no longer collect PCIA charges from the customers included in each vintage.

ANSWER 1

The following forecasted end dates for the Power Charge Indifference Adjustment ("PCIA") are based on current expiration dates of the contracts applicable to each vintage. The actual end date may vary. In addition, while the PCIA may still exist through these dates for a particular vintage, the PCIA amount in any given year could be $0 or negative up to the level of the ongoing Competition Transition Charge ("CTC") if the portfolio costs are below-market or if a positive indifference amount is offset by an accrued negative indifference amount for a particular vintage.

<table>
<thead>
<tr>
<th>Vintage</th>
<th>Forecasted End Date of PCIA</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>December 2041</td>
</tr>
<tr>
<td>2011</td>
<td>December 2041</td>
</tr>
<tr>
<td>2012</td>
<td>December 2043</td>
</tr>
<tr>
<td>2013</td>
<td>December 2043</td>
</tr>
<tr>
<td>2014</td>
<td>December 2043</td>
</tr>
<tr>
<td>2015</td>
<td>December 2043</td>
</tr>
<tr>
<td>2016</td>
<td>December 2043</td>
</tr>
</tbody>
</table>
ATTACHMENT 4:

PG&E Response to MCE Data Request 003 – Question 4


SUBJECT: **POWER CHARGE INDIFFERENCE ADJUSTMENT (PCIA)**

**QUESTION 4**

In its response to Question 1 of MCE’s prior data request, PG&E states that it anticipates the present vintages of CCA departing load to be responsible for paying back the PCIA through either 2041 or 2043 depending upon their respective vintages. Furthermore, conventional power purchase contracts are limited to 10 years of stranded cost recovery under the PCIA while renewable contracts are limited to the life of the contract (which is capped at 20 years) for stranded cost recovery under the PCIA. With these facts in mind please answer the following questions:

Please explain why PG&E’s forecasted end dates for PCIA cost recovery span approximately 30 years from the creation date of each customer vintage.

**ANSWER 4**

The question suggests that stranded cost recovery for renewable contracts are “limited to the life of the contract (which is capped at 20-years) . . .” Renewable contracts are recoverable for the life of the contract pursuant to D.04-12-048. See Conclusion of Law 16 and Ordering Paragraph 10:

**COL 16, in part**

. . . Stranded costs arising from RPS procurement activities should be collected from all customers, including departing load, over the life of the contract . . .

**OP 10**

We adopt the 15-year standard for new fossil-fueled resources acquired by the utilities. For all other contracts, including contracts for renewable generation, the utilities should be allowed recovery over the life of the contract.
Pursuant to California Public Utilities Commission ("Commission") decisions, above-market costs associated with renewable contracts are recoverable for the term of the contract. PG&E’s previous response to Question 1 of MCE’s second data request identified an end date of 2041 for the 2010 and 2011 vintages based on the expiration date of the last renewable contract in the portfolio. The contract was signed in 2010 and is forecast to come online later in 2016. The term of the contract is 25 years.

Similarly, the end dates for vintages 2012 through 2016 were based on the end date of the last renewable contracts in those portfolios. In this case, there are three contracts that were signed in 2012 and are forecast to come online in 2019 with an expiration date of 2043.

PG&E did qualify that the actual end date may vary and that even though the PCIA may still exist through these dates for a particular vintage, the PCIA amount in any given year could be $0 or negative up to the level of the ongoing Competition Transition Charge ("CTC") if the portfolio costs are below-market or if a positive indifference amount is offset by an accrued negative indifference amount for a particular vintage.
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA


Rulemaking 15-03-011
(Filed March 26, 2015)

REPLY COMMENTS OF JOINT CCA PARTIES
ON ASSIGNED COMMISSIONER AND ASSIGNED ADMINISTRATIVE LAW JUDGE’S SCOPING MEMO AND RULING SEEKING PARTY COMMENTS

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Counsel for the City of Lancaster

February 12, 2016
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BEFORE THE PUBLIC UTILITIES COMMISSION
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REPLY COMMENTS OF JOINT CCA PARTIES
ON ASSIGNED COMMISSIONER AND ASSIGNED ADMINISTRATIVE LAW JUDGE’S SCOPING MEMO AND RULING SEEKING PARTY COMMENTS

I. INTRODUCTION

Pursuant to Rule 14.3 of the California Public Utility Commission’s (“Commission”) Rules of Practice and Procedure, Marin Clean Energy (“MCE”) and Lancaster Clean Energy (“LCE”) respectfully submits the following reply comments as Joint Community Choice Aggregation (“CCA”) Parties on the Assigned Commissioner and Assigned Administrative Law Judge’s Scoping Memo and Ruling Seeking Party Comments. The Joint CCA Parties’ reply comments respond to parties’ comments that raised issues related to i) the appropriateness of revising storage procurement targets of different Load Serving Entities (“LSEs”), ii) cost recovery policies and concerns, and iii) providing storage eligibility to controlled charging.
II. THE COMMISSION SHOULD REFRAIN FROM REVISING STORAGE PROCUREMENT TARGETS

Several parties recommended that the Commission should not consider revising energy storage procurement targets at this point of time.\(^1\) This view is shared by the Joint CCA Parties and reflected in their opening comments. Specifically, TURN pointed to the absence of data and analysis that have demonstrated the need to increase or decrease the mandated energy storage procurement targets.\(^2\) The Joint CCA Parties agree with other parties that it is premature to reconsider storage procurement targets, given that these procurement targets are new and most LSEs are just beginning their storage procurement.

Furthermore, the long term goal the Commission and LSEs working toward should be the elimination of mandated targets, when storage resources can compete and provide services with other energy resources. If the Commission is concerned that the current mandates may be insufficient to help storage resources become more competitive, the Commission could consider developing mechanisms to assess the market readiness of storage resources\(^3\) in the future to determine whether procurement targets before 2020 should be revised, and if it will be necessary to adopt further procurement mandates beyond 2020.

III. THE COMMISSION SHOULD ADDRESS THE METHODOLOGY FOR PCIA CALCULATION AND OTHER COST RECOVERY MECHANISMS IN TRACK 2

Alliance for Retail Energy Markets (“AReM”) and Direct Access Customer Coalition’s (“DACC”) opening comments suggested the Commission to examine the methodology for

\(^1\) Parties that provided comments include the Alliance for Retail Energy Markets (“AReM”) and Direct Access Customer Coalition (“DACC”), Office of Ratepayer Advocates (“ORA”), San Diego Gas & Electric (“SDG&E”), and The Utility Reform Network (“TURN”).

\(^2\) Opening Comments of TURN, pg. 2.

\(^3\) Opening Comments of Environmental Defense Fund (“EDF”), pg. 3.
calculating the PCIA for storage in Track 2, rather than in separate IOU application proceedings. Although Southern California Edison (“SCE”) did not recommend addressing this issue in its opening comments on Track 2 issues, SCE did support moving the PCIA-related issues to Track 2 of the Energy Storage OIR in its reply to protests and responses to its 2014 Energy Storage application. The Joint CCA Parties agree with AReM, DACC, and SCE that the calculation of the PCIA for storage should be addressed in this proceeding as this issue impacts all unbundled ratepayers. Treating the PCIA on a case-by-case basis could create inconsistent policies among different IOU territories in different application cycles, and create uncertainties for the procurement strategies of CCAs.

The Joint CCA Parties also echo the comments made by AReM/DACC and Shell Energy of North America (“Shell Energy”) about the lack of transparency and fairness of calculation of the PCIA for storage resources. As Shell Energy stated in its opening comments, the above-market costs of energy storage are not calculable, because storage is a new resource that offers multiple benefits and functions. AReM and DACC pointed out in their opening comments the need for more transparency for PCIA calculation, and that PG&E has not offered detailed explanation on how cost allocation would be calculated and implemented in its storage application.

Based on these comments, the Joint CCA Parties urge the Commission to use Track 2 to address PCIA and other cost recovery mechanisms to provide transparency and consistency. The Commission can first conduct workshops on cost recovery policies and concerns, as recommended

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4 Opening Comments of AReM and DACC at pg. 14.
5 SCE’s Reply to Protests and Responses to Its Application for Approval of Contracts Resulting from Its 2014 Energy Storage Request for Offers, pg. 3.
6 Opening Comments of AReM and DACC at pg. 15, 16; Opening Comments of Shell Energy of North America at pg. 3-5.
7 Id.
8 Opening Comments of AReM and DACC at pg. 16.
by ORA, so long as there are official records of the discussions to solicit comments from parties. If parties’ concerns cannot be addressed in workshops, then evidentiary hearings can be requested according to the directions provided in the Scoping Memo.

IV. THE COMMISSION SHOULD CONSIDER CONTROLLED CHARGING AS AN ELIGIBLE ENERGY STORAGE TECHNOLOGY AND RELATED ISSUES

The Alliance of Automobile Manufacturers (“Alliance”) and American Honda Motor Co., Inc. (“Honda”) filed joint opening comments that recommended the Commission to include controlled charging as an eligible energy storage technology. EDF filed separate comments that recommended the Commission to re-consider controlled charging, or V1G, as an eligible resource.9 Conceptually, the Joint CCA Parties are supportive of counting controlled charging as an eligible storage resource because controlled charging can either already meet, or has the potential to meet the three guiding principles of the ESP program.10

However, there are several issues that warrant the Commission’s consideration if controlled charging is approved as an eligible storage resource. There may be implications on whether procurement targets should be revised, and the accounting of capacity procured toward LSE’s targets. Lastly, as EDF recommended, the use of controlled charging should be capped to prevent the crowding out of other storage technologies.11

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9 Opening Comments of EDF at pg. 4.
10 D.13-10-040, pg. 9-10. The three principles are i) the optimization of the grid, including peak reduction, contribution to reliability needs, or deferment of transmission and distribution upgrade investments; ii) The integration of renewable energy; and iii) The reduction of greenhouse gas emissions to 80 percent below 1990 levels by 2050, per California goals.
11 Opening Comments of EDF at pg. 6.
V. **CONCLUSION**

The Joint CCA Parties thank Assigned Commissioner Peterman and Assigned Administrative Law Judge DeAngelis for the opportunity to provide these reply comments.
Respectfully submitted,

/s/ C.C. Song
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/s/ Ty Tosdal
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E-mail: ty@tosdallaw.com
Counsel for the City of Lancaster

February 12, 2016
Attachment 2

Compliance Filing for LSEs with Long-Term Financial Commitments

February 16, 2016

CA Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

Re: GHG Environmental Performance Standard (EPS) Compliance Filing 2016

Pursuant to Ordering Paragraph No. 4 of Decision (“D.”) 07-01-039, issued in R. 06-04-009 on January 25, 2007, Marin Clean Energy submits this annual Attestation Letter affirming that the financial commitments Marin Clean Energy has entered into for generation during the prior calendar year are in compliance with the greenhouse gas (“GHG”) emissions performance standard (“EPS”). Specifically, Marin Clean Energy is in compliance with the EPS. Documentation supporting that compliance is provided below.

Effective Date: March 16, 2016

Tier Designation: Tier 2 Designation

Purpose

This Attestation Letter provides information and documentation required by D.07-01-039 for LSEs (electrical corporation, electric service provider, or community choice aggregator) with new long-term financial commitments (defined on Page 3 in Attachment 7 of D.07-01-039). This Attestation Letter demonstrates that for 2015 all financial commitments entered into by Marin Clean Energy are compliant with the EPS.

Background

D.07-01-039 requires all Load Serving Entities (“LSEs”) to file annual Attestation Letters, due February 15th of each year, attesting to the Commission that the financial commitments entered into for generation during the prior calendar year are in compliance with the EPS. D.07-01-039 requires LSEs to file Attestation Letters as an advice letter and serve the Attestation Letter on the service list in Rulemaking (“R.”) 06-04-009. This Attestation Letter is filed pursuant to that process.

D.07-01-039 requires LSEs to include a listing of long-term financial commitments of five years or longer that they have entered into during the prior year. Note that long-term financial commitments can be compliant if any of the following apply:
1. Not in a baseload powerplant;
2. Generation using pre-approved renewable resource technology;
3. Existing combined-cycle combustion turbine (in operation/or permitted to operate as of 6/30/07) with an increase in rated capacity less than 50 megawatts (MW);
4. Net emission rate of each baseload facility underlying a covered procurement does not exceed 1,100 lbs of CO₂ per megawatt hour (MWh);
5. Exemption related to: reliability exemption, extraordinary circumstances or financial harm, and CO₂ sequestration through injection in geological formations.

D.07-01-039 requires all LSEs to disclose the investment amount and type of alteration to retained generation, by generation facility and unit. D.07-01-039 also advises LSEs to present documentation regarding the design and intended use of the powerplant(s) underlying their new long-term financial commitments utilizing the sources of information listed in § 8341(b)(4), as well as any other sources of documentation that they believe will be relevant to this determination.

D.07-01-039 emphasizes that the key concept is to establish the design and intended use of the powerplant. Accordingly, documentation of the annualized plant capacity factor for the powerplant should include historical annual averages in order to help determine whether the plant is “designed and intended” to be used for baseload generation. D.07-01-039 requires LSEs to provide documentation of capacity factors, heat rates and corresponding emissions rates that reflect the actual, expected operations of the plant.

This Attestation Letter comports with the requirements outlined above.

**Protests**

This compliance filing is not subject to protest pursuant to General Order 96-B, Energy Industry Rule 9.

**Correspondence**

Any correspondence regarding this compliance filing should be sent by email to the attention of:

**Martha Serianz**
**Regulatory Coordinator**
Marin Clean Energy
1125 Tamalpais Ave.
San Rafael, CA 94109
(415) 464-6043
mserianz@mceCleanEnergy.org
Compliance Documentation

The following listings and/or tables provide detailed and specific information regarding Marin Clean Energy contracts and long-term financial commitments that are subject to the EPS requirements. The compliance documentation must match the compliance category outlined previously. For example, the information provided must demonstrate that the net emissions rate of each baseload facility underlying a covered procurement is no higher than 1,100 lbs of carbon dioxide (CO₂) per megawatt hour (MWh).

1. Include a complete and detailed listing of the new long-term financial commitments of five years or longer they have entered into during the prior year with documentation to demonstrate:
   a. Documentation demonstrating that such procurements are EPS compliant, including any contracts with a term of five years or longer that include provisions for substitute energy purchases;
   b. For any requested reliability-based exemptions that have been pre-approved by the Commission, reference to the application and Commission decision number.

2. The complete listing of new long-term financial commitments of five years or longer must include “linked” contracts whose combined term is five years or longer.

3. Disclosure of LSE investments in retained generation, including “deemed-compliant” combined cycle gas turbines (CCGTs). All LSEs are to disclose the investment amount and a breakdown of alterations or refurbishments to retained generation, by generation facility and unit.

4. Present documentation regarding the designed and intended use of the powerplant(s) underlying their new long-term financial commitments utilizing the sources of information listed in § 8341 (b)(4), as well as any other sources of documentation relevant to the determination.

5. Provide documentation of capacity factors (for definition of capacity factor see Section 5.6 of D.07-01-039.), heat rates and corresponding emissions rates that reflect the actual, expected operation of the plant (not full load heat rate). Documentation of the annualized plant capacity factor for the power plant should include historical annual averages in order to determine whether the plant is “designed and intended” to be used for baseload generation at an annualized plant capacity factor of at least 60 percent.

MCE’s long term financial commitments entered into during the prior year are detailed in the following table. These long-term financial commitments are EPS compliant as they are with non-baseload generation resources or with pre-approved renewable energy technologies.
### Table 1 – EPS Compliant Contracts

<table>
<thead>
<tr>
<th>Contract</th>
<th>Execution Date</th>
<th>Technology</th>
<th>EPS Compliant</th>
<th>Compliance Category</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cooley Quarry 2</td>
<td>7/1/2015</td>
<td>Photovoltaic</td>
<td>Yes</td>
<td>Non-Baseload</td>
</tr>
<tr>
<td>Cost Plus</td>
<td>4/16/2015</td>
<td>Photovoltaic</td>
<td>Yes</td>
<td>Non-Baseload</td>
</tr>
<tr>
<td>EBMUD</td>
<td>6/18/2015</td>
<td>Hydroelectric</td>
<td>Yes</td>
<td>Non-Baseload</td>
</tr>
<tr>
<td>MCE Solar One</td>
<td>3/5/2015</td>
<td>Photovoltaic</td>
<td>Yes</td>
<td>Non-Baseload</td>
</tr>
</tbody>
</table>

### Exemption Process Requirements (if applicable)

Or if Marin Clean Energy is claiming an exemption the following applies:

1. All LSEs are required to file (1) an application requesting Commission pre-approval for a reliability exemption, (2) a petition for modification of the decision where the request is based on “extraordinary circumstances, catastrophic events, or threat of significant financial harm” or (3) an application for covered procurements that employ geological formation inject for CO2 sequestration.

### Certification

1. I have reviewed, or have caused to be reviewed, this compliance submittal.

2. Based on my knowledge, information, or belief, this compliance submittal does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements true.

3. Based on my knowledge, information, or belief, this compliance submittal contains all of the information required to be provided by Commission orders, rules, and regulations.

Include the name and contact information for the LSE officer certifying the above:

By: Dawn Weisz, Chief Executive Officer  
Dated: February 16, 2016  
Marin Clean Energy  
1125 Tamalpais Ave.  
San Rafael, CA 94109  
(415) 464-6020  
dweisz@mceCleanEnergy.org
CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY LSE (Attach additional pages as needed)

<table>
<thead>
<tr>
<th>Marin Clean Energy</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utility type:</td>
</tr>
<tr>
<td>ELC = Electric</td>
</tr>
<tr>
<td>GAS = Gas</td>
</tr>
<tr>
<td>PLCL = Pipeline</td>
</tr>
<tr>
<td>HEAT = Heat</td>
</tr>
<tr>
<td>WATER = Water</td>
</tr>
<tr>
<td>Phone #: 415-464-6043</td>
</tr>
<tr>
<td>E-mail: <a href="mailto:mserianz@mcecleanenergy.org">mserianz@mcecleanenergy.org</a></td>
</tr>
</tbody>
</table>

EXPLANATION OF UTILITY TYPE

<table>
<thead>
<tr>
<th>ELC = Electric</th>
<th>GAS = Gas</th>
<th>PLCL = Pipeline</th>
<th>HEAT = Heat</th>
<th>WATER = Water</th>
</tr>
</thead>
</table>

Advice Letter (AL): 13-E
Subject of AL: GHG Emission Performance Standard (EPS) filing 2016
Tier Designation: ☑ 1 ☐ 2 ☑ 3
Keywords (choose from CPUC listing): AL filing type:
☐ Monthly ☐ Quarterly ☑ Annual ☐ One-Time ☐ Other ____________________________
If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution: D.07-01-039
Does AL replace a withdrawn or rejected AL? If so, identify the prior AL ____________________________
Summarize differences between the AL and the prior withdrawn or rejected AL: ____________________________
Resolution Required? ☐ Yes ☑ No
Requested effective date: March 17, 2016
No. of tariff sheets: ____________________________
Estimated system annual revenue effect: (%): ____________________________
Estimated system average rate effect (%): ____________________________
When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).
Tariff schedules affected:
Service affected and changes proposed:
Pending advice letters that revise the same tariff sheets:

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

<table>
<thead>
<tr>
<th>CPUC, Energy Division</th>
<th>Martha Serianz</th>
</tr>
</thead>
<tbody>
<tr>
<td>Attention: Tariff Unit</td>
<td>Marin Clean Energy</td>
</tr>
<tr>
<td>505 Van Ness Ave.,</td>
<td>1125 Tamalpais Ave.</td>
</tr>
<tr>
<td>San Francisco, CA 94102</td>
<td>San Rafael, CA 94901</td>
</tr>
<tr>
<td><a href="mailto:EDTariffUnit@cpuc.ca.gov">EDTariffUnit@cpuc.ca.gov</a></td>
<td><a href="mailto:mserianz@mceCleanEnergy.org">mserianz@mceCleanEnergy.org</a></td>
</tr>
</tbody>
</table>

1 Discuss in AL if more space is needed.
February 26, 2016

CA Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

Advice Letter MCE E-14

RE: REFILING MARIN CLEAN ENERGY’S BIANNUAL ENERGY STORAGE PROCUREMENT COMPLIANCE REPORT

EFFECTIVE DATE

MCE requests that this Tier 2 advice filing become effective on March 27, 2016, which is 30 days following the issuance of this letter.

TIER DESIGNATION: Tier 2 Designation

PURPOSE

California Public Utilities Commission (“Commission”) Decision (“D.”) D.13-10-040, Decision Adopting Energy Storage Procurement Framework and Design Program (“Decision”), establishes an energy storage procurement goal of 1% of 2020 annual peak load for Community Choice Aggregation (“CCA”) programs. MCE submits this Tier 2 Advice Letter to inform the Commission about the status of its energy storage procurement activities and its progress toward meeting the goal. MCE has already secured 0.8 MW of energy storage, and expects to procure a total of 3.2 MW by 2020, serving 1% of its 2020 annual peak load. Since the first energy storage project that MCE has helped to bring online is partially funded by the Self-Generation Incentive Program, as directed by Decision (“D.”) 16-01-032, MCE and the Pacific Gas and Electric Company (“PG&E”) each receives 50% (i.e. 0.8 MW) of the projects total 1.6 MW capacity to count toward their energy storage procurement targets. As such MCE has already satisfied a quarter of its projected energy storage procurement compliance obligation due to D.13-10-040.

BACKGROUND

The Commission issued D.13-10-040 on December 21, 2013, pursuant to Assembly Bill (“AB”) 2514, and adopted the Energy Storage Procurement Framework and Design Program for Investor Owned Utilities (“IOUs”), Electric Service Providers (“ESPs”), and CCA programs. D.13-10-040 establishes a goal for CCA programs to procure energy storage equal to 1% of their 2020 annual peak load. While this goal does not have to be met until 2020, the Commission stated

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1 D.16-01-032 at 61.
2 D.13-10-040 at 43, 47.
that it does not want CCA programs “to delay procurement until that time,” so D.13-10-040 accordingly requires that each CCA program file a Tier 2 Advice Letter every two years to show progress toward the 2020 goal beginning on January 1, 2016.³

To count toward the 2020 goal, energy storage projects must meet the following eligibility requirements:

1. **Energy storage systems must be installed and operational after January 1, 2010:** As required by California Public Utility Code section 2835, subdivision (c), a “new energy storage system” is a “system that is installed and first becomes operational after January 1, 2010.”

2. **Energy storage systems must be online and delivering by the end of 2024:** All 2020 compliance target procurements must be “installed,”⁴ or “online and delivering,” by December 31, 2024.⁵

3. **Distributed storage qualifies:** The Commission “shall allow customer sited or customer-owned energy storage to count toward the 1% target” for CCA programs.⁶

4. **Electric vehicle programs qualify:** IOUs, ESPs, and CCA programs may count “[e]nergy storage that could be obtained from plug-in vehicles and programs/systems that utilize electric vehicles for grid services (Vehicle to Grid)” for their procurement goals.⁷

5. **Storage funded by departing utility customers is excluded:** The load associated with customers departing from utility bundled services for CCA participation “shall not be counted towards meeting the CCA or ESP’s 1 percent procurement target.”⁸

6. **Energy storage projects must further a relevant purpose:** Projects must demonstrate their ability to meet one or more of the following purposes: grid optimization, integration of renewable energy, or reduction of greenhouse gas emissions.⁹

7. **Government funded projects may be included:** “It is reasonable to include any PIER- or EPIC- funded projects toward the procurement targets under certain conditions.”¹⁰

8. **Energy storage procurement must be cost-effective:** AB 2514 provides that energy storage must be “viable and cost-effective,” but the Commission has not adopted a

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³ D.13-10-040 at 47.
⁴ D.13-10-040 at 43.
⁵ D.13-10-040 at 48.
⁶ D.13-10-040 at 59.
⁷ D.13-10-040 at 32; Appendix A, at 5.
⁸ D.13-10-040 at 48.
⁹ D.13-10-040 at 32; Appendix A at 3.
¹⁰ D.13-10-040 at 63.
specific cost-effectiveness methodology. D.13-10-040 requires each CCA program to “describe its methodology for measuring cost-effective projects.”

**COST-EFFECTIVENESS**

MCE considers an energy storage project to be “cost-effective” if the upfront and operational costs of the project can be offset fully by monetary benefits resulting from the utilization of the project. These benefits can either result in revenue return to MCE or to a specific MCE customer if there is direct customer involvement. These benefits can manifest as both short-term gains and long-term cost-savings. So long as these benefits meet or exceed the costs associated with the energy storage project, then MCE will consider this project as cost-effective. MCE will compare any proposed energy storage project costs with other proposals and publicly available information about energy storage project cost metrics to make sure that individual bids are competitive.

At this time MCE is focused on facilitating behind the meter customer-sited battery storage projects by:

- hosting workshops for battery providers and large commercial and industrial customers
- providing on bill payment of demand charge savings to simplify the billing process
- partnering with other entities on grant applications that include a storage component
- creating a pilot battery tariff that offers residential customers a monthly incentive in exchange for control over dispatching their battery
- exploring new value streams for batteries through demand response and the wholesale market

MCE’s practice at this time is to seek cost effective battery solutions that rely entirely on demand charge savings, SGIP (or other grant) funds or bidding load-shed to make the cost effectiveness of the projects pencil out. To date MCE has chosen not to leverage ratepayer funds to subsidize the costs of its energy storage procurement obligation; however, as new funding streams develop in the future, it may become cost-effective to leverage ratepayer funding to cover upfront costs provided that these costs be repaid through the controlled usage of this energy storage.

Going forward MCE hopes to leverage additional monetary streams of benefits to offset upfront and ongoing costs of energy storage. Some of these additional funding streams include pass-through of distribution grid-related benefits resulting from distributed resource deployment and control (per the Distributed Resources Plan (“DRP”) Rulemaking (“R.”) 14-08-013 and payments for participating within California Independent System Operator (“CAISO”) markets to provide transmission grid-related benefits (per the Energy Storage and Distributed Energy Resources (“ESDER”) market that is presently being implemented). However because CCAs only have an indirect role in influencing and optimizing electricity grid operations and investments, it will likely provide challenging to gain access to these additional revenue streams.

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11 D.13-10-040, OP 5 at 77.
ENERGY STORAGE PROJECTS

MCE helped to facilitate two Tesla battery installations on College of Marin’s (“COM”) campuses totaling 1.6 MW of storage capacity. The projects received SGIP funds and will not require the College of Marin to make any upfront investments. Tesla and COM will use MCE’s on bill payment mechanism to split demand charge savings between Tesla and COM through COM’s utility bill.

MCE and Tesla are currently considering further opportunities for collaboration on a residential battery program. In addition to co-marketing the battery systems, MCE may also assist with the installation process. Residential battery customers will also be offered a monthly incentive to sign up for MCE’s pilot battery tariff which will give MCE access to controlling the dispatch of their batteries within certain parameters.

MCE plans to procure at least 3.2 MW of eligible energy storage by 2020, in compliance with D.13-10-040. This storage will serve 1% of MCE’s projected annual peak load for 2020, which is projected to be 316 MW. Additional details about the energy storage contracts that MCE entered into can be found in Appendix A: MCE Energy Storage Contracts, including the technology, number of MW, number of MWh and duration of the contracts. As discussed above, these projects will be cost effective.

COUNTING OF SGIP-FUNDED PROJECTS

The matter of whether or not CCAs are able to count energy storage projects funded partially with SGIP funds was decided within the Commission’s Energy Storage Roadmap Rulemaking (“R.”) 15-03-011. On January 28, 2016, the Commission adopted Decision (“D.”) 16-01-032 on this matter. The Commission determined that the credit for SGIP-funded installations should be split 50/50 between the IOU and the CCA/ESP. Based on the Decision, 0.8 MW of the Tesla battery installations on the campuses of the College of Marin will count toward MCE’s storage compliance obligation.

APPENDICIES: Appendix A: MCE Energy Storage Projects

NOTICE

Anyone wishing to protest this advice filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests should be mailed to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
E-mail: EDTariffUnit@cpuc.ca.gov

12 D. 16-01-032 at 61.
Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address above).

In addition, protests and all other correspondence regarding this advice letter should also be sent by letter and transmitted via facsimile or electronically to the attention of:

Jeremy Waen  
Senior Regulatory Analyst  
MARIN CLEAN ENERGY  
1125 Tamalpais Ave.  
San Rafael, CA 94901  
Phone: (415) 464-6027  
Facsimile: (415) 459-8095  
jwaen@mceCleanEnergy.org

Martha Serianz  
Regulatory Coordinator  
MARIN CLEAN ENERGY  
1125 Tamalpais Ave.  
San Rafael, CA 94901  
Phone: (415) 464-6043  
Facsimile: (415) 459-8095  
mserianz@mceCleanEnergy.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

MCE is serving copies of this advice filing to the relevant parties shown on the R.10-10-007 service list. MCE is also serving copies of this advice filing as a courtesy to the newer energy storage roadmap proceeding R.15-03-011. For changes to these service lists, please contact the Commission’s Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

**CORRESPONDENCE**

For questions, please contact Jeremy Waen at (415) 464-6027 or by electronic mail at jwaen@mceCleanEnergy.org.

/s/ Jeremy Waen  
Jeremy Waen  
Senior Regulatory Analyst  
MARIN CLEAN ENERGY

cc:  
Service List R.10-10-007  
Service List R.15-03-011
## APPENDIX A:
**MCE ENERGY STORAGE PROJECTS**

<table>
<thead>
<tr>
<th>Project</th>
<th>Technology</th>
<th>Using SGIP Funding</th>
<th>Total Capacity (MW)</th>
<th>Countable Capacity (MW)</th>
<th>Maximum Discharge (MWh)</th>
<th>Maximum Discharge Duration</th>
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</thead>
<tbody>
<tr>
<td>College of Marin</td>
<td>Tesla Lithium Battery</td>
<td>Yes</td>
<td>1.6</td>
<td>0.8</td>
<td>3.2</td>
<td>2 hours</td>
</tr>
</tbody>
</table>
MUST BE COMPLETED BY LSE (Attach additional pages as needed)

<table>
<thead>
<tr>
<th>Company name/CPUC Utility No.</th>
<th>Marin Clean Energy</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utility type:</td>
<td></td>
</tr>
<tr>
<td>☑ ELC</td>
<td>☐ GAS</td>
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<tr>
<td>☐ PLC</td>
<td>☐ HEAT</td>
</tr>
<tr>
<td>☐ WATER</td>
<td></td>
</tr>
<tr>
<td>Contact Person for questions and approval letters:</td>
<td>Jeremy Waen</td>
</tr>
<tr>
<td>Phone #:</td>
<td>(415) 464-6027</td>
</tr>
<tr>
<td>E-mail:</td>
<td><a href="mailto:jwaen@mcecleanenergy.org">jwaen@mcecleanenergy.org</a></td>
</tr>
</tbody>
</table>

**EXPLANATION OF UTILITY TYPE**

ELC = Electric  GAS = Gas  
PLC = Pipeline  HEAT = Heat  WATER = Water

Advice Letter (AL) #: MCE 12-E

Subject of AL: Marin Clean Energy’s Biannual Energy Storage Procurement Compliance Report

Tier Designation: ☑ 1 ☐ 2 ☐ 3

Keywords (choose from CPUC listing): Compliance

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☐ One-Time ☑ Biannual

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution: D.13-10-040

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL ________________

Summarize differences between the AL and the prior withdrawn or rejected AL: ________________

Resolution Required? ☐ Yes ☑ No

Requested effective date: March 27, 2016  No. of tariff sheets: 0

Estimated system annual revenue effect: (%) : n/a

Estimated system average rate effect (%) : n/a

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: n/a

Service affected and changes proposed: n/a

Pending advice letters that revise the same tariff sheets: n/a

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division  CCA Info (including e-mail)
Attention: Tariff Unit  Marin Clean Energy
505 Van Ness Ave.  1125 Tamalpais Ave.
San Francisco, CA 94102  San Rafael, CA 94901
EDTariffUnit@cpuc.ca.gov  jwaen@mcecleanenergy.org