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

Rulemaking Regarding Whether, or Subject to What Conditions, the Suspension of Direct Access May Be Lifted Consistent with Assembly Bill 1X and Decision 01-09-060.	Rulemaking 07-05-025 (Filed May 24, 2007)

OPENING BRIEF OF CALIFORNIA STATE UNIVERSITY, MARIN ENERGY AUTHORITY, CALIFORNIA MUNICIPAL UTILITIES ASSOCIATION, CITY AND COUNTY OF SAN FRANCISCO, SAN JOAQUIN VALLEY POWER AUTHORITY, ALLIANCE FOR RETAIL ENERGY MARKETS, DIRECT ACCESS CUSTOMER COALITION, BLUESTAR ENERGY, PILOT POWER GROUP, INC. AND ENERGY USERS FORUM

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SUMMARY OF RECOMMENDATIONS

- The Commission should adopt the proposal by the Joint Parties for developing a Green Benchmark to value Renewable Portfolio Standard ("RPS")-compliant renewable resources in the IOUs' supply portfolios using data on the cost of recent IOU procurement of RPS-compliant renewable resources that is already complied by the IOUs in annual Energy Resource Recovery Account ("ERRA") proceedings.

- The Commission should require the IOUs to value all energy that the IOUs use to claim RPS-credit using the Green Benchmark and should reject the arguments of Pacific Gas and Electric Company ("PG&E") and San Diego Gas and Electric Company ("SDG&E") that the Green Benchmark should only be used to value post 2003 renewable resources.

- The Commission should require the IOUs to adjust the Market Price Benchmark ("MPB") to reflect the value of the IOUs' supply portfolios' shape, using the load profile of bundled customers as a proxy.

- The Commission should update the capacity value used in the MPB and should require that the capacity value be calculated annually using the Net Qualifying Capacity ("NQC") of each vintaged portfolio and a proxy capacity price of $55/kw-year until further notice.

- The Commission should clarify that neither load-based California Independent System Operator ("CAISO") charges nor congestion costs should be included in the Total Portfolio Cost and should direct the Investor Owned Utilities ("IOUs") to demonstrate that this directive has been followed when they update the Power Charge Indifference Adjustment ("PCIA") and the Competition Transition Charge ("CTC") charges in accordance with the CPUC's decision.

- The Commission should clarify that short-term purchases, those that are under one year, should not be included in the Total Portfolio Cost.

- The Commission should apply the changes to the calculation of the MPB that are adopted for purposes of calculating PCIA to the calculation of the MPB used for purposes of calculating CTC.

- The Commission should reject witness Reid's proposal that would limit the ability of Community Choice Aggregators ("CCAs") and Energy Service Providers ("ESPs") to develop their own portfolio of RPS compliant resources.

- The Commission should reject PG&E's proposal to artificially restrict the PCIA from dipping below zero.

- The Commission should require the IOUs to revise the PCIA and CTC in accordance with the changes described above as soon as possible.

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In accordance with the directive of Administrative Law Judge ("ALJ") Pulsifer on the last day of hearings, March 30, 2011,[1] and Rule 13.11 of the Commission's Rules of Practice and Procedure, the California State University, Marin Energy Authority ("MEA"), the California Municipal Utilities Association, the City and County of San Francisco ("CCSF"), San Joaquin Valley Power Authority, Alliance for Retail Energy Markets ("AReM"), [2] Direct Access Customer Coalition ("DACC"),[3] BlueStar Energy, Pilot Power Group, Inc. and the Energy Users Forum (hereafter collectively referred to as the "Joint Parties") submit this opening brief on certain Phase 3 hearing issues.[4] [5]

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[1] Reporter's Transcript ("RT") at 716: 5-7 (ALJ Pulsifer).

[2] AReM is a California mutual benefit corporation formed by electric service providers that are active in California's direct access market. The positions taken in this filing represent the views of AReM but not necessarily individual members or the affiliates of its members with respect to the issues addressed herein.

[3] DACC is a regulatory alliance of educational, commercial, industrial and governmental end-use customers that utilize direct access for all or a portion of their electricity load requirements.

[4] Representatives of BlueStar Energy, California State University, Energy Users Forum and Pilot Power Group, Inc, have informed Ms. Solé that these groups wish to sign on to this brief.

[5] Unless otherwise stated, all statutory references are to the Public Utilities Code.

This joint opening brief addresses the methodology for determining the Power Charge Indifference Adjustment ("PCIA") and Competition Transition Charge ("CTC"). This track of the proceeding also addresses the Transitional Bundled Service ("TBS") rate components and their calculation, and proposals and recommendations for Direct Access switching rules and ESP financial security requirements. The Joint Parties do not address those issues in this brief. Those issues may be addressed by a subset of the Joint Parties, the Direct Access Parties, and other members of the Joint Parties in their respective individual opening briefs filed today. Numbering of this opening brief reflects the numbering that parties agreed to in the model briefing outline, which accounts for the gap in numbering that will be seen below.

I. Methodology for determining the PCIA and ongoing CTC

There is general consensus among the Parties that the objective of cost responsibility surcharges ("CRS") and nonbypassable charges ("NBCs") should be to achieve bundled customer indifference to the departure of load.[6] As the Commission stated in D.08-09-012:

> In addressing issues related to NBCs, the Commission has generally applied the bundled customer indifference principle, whereby bundled customers should be no worse off, nor should they be any better off as a result of customers choosing alternative energy supplies (ESP, CCA, POU or customer generation). The Commission has also supported the principle that stranded costs should be recovered from those customers who benefited from the stranded asset, as well as those customers on whose behalf the IOU incurred these costs. It is reasonable that we continue to use these guiding principles in reconciling issues related to the implementation of the D.04-12-048 and D.06-07-029 NBCs.[7]

[6] Exh. 100 at 5 (Joint Parties: Dalessi, Fulmer, Meal); Exh. 300 at 17-18 (Southern California Edison (“SCE”): Schichtl); Exh. 400 at 1-3 through 1-5 (Pacific Gas and Electric Company (“PG&E): Barry); Exh. 501 at CF-2 through CF-3 (San Diego Gas and Electric Company ("SDG&E"): Fang); Exh. 600 at 1: 10-18 (Division of Ratepayer Advocates (“DRA”): Ouyang); Exh. 800 at 5: A7 (California Large Energy Consumers Association and the California Manufacturers and Technology Association (“CLECA/CMTA”): Barkovich).

[7] D.08-09-012 at 10.

To achieve this objective, the Commission has generally required the collection of NBCs from customers who depart Investor Owned Utility ("IOU") bundled service to take service from a Community Choice Aggregator ("CCA"), Energy Service Provider ("ESP"), or a Publicly Owned Utility ("POU").[8] The CPUC has developed a methodology to determine the NBCs in decisions over the past decade, with the most recent significant modifications taking place in 2008. In its last significant decision on the matter, D.08-09-012, the Commission recognized that the methodology for determining NBCs might continue to require updating in the future to accommodate changing market conditions and other factors.[9] The Commission explained that "[i]f, due to future changing circumstances, the processes adopted by this decision for determining the D.04-12-48 [non-by-passable charges ("NBCs")] become unworkable, unbalanced, or unfair, parties may propose and request modifications to the form of the NBC or how the NBC should be determined or calculated."[10]

The current methodology to calculate NBCs was explained as follows by SCE witness Schichtl with respect to SCE, but his explanation is generally applicable to all IOUs and consistent with the bulk of testimony on this point:

> For each vintage year, SCE calculates the cost of the total portfolio of all generation resources procured for that year to serve bundled service customers' load [(the "Total Portfolio Cost")]. The generation portfolio for each vintage year includes all resources and contracts entered into to serve the bundled load. This includes all previous contracts still in place and new ones signed for that particular year. The "total portfolio" cost for each vintage year is calculated on an annual basis and compared to the market value of energy and capacity produced by the portfolio.
>
> Pursuant to D.06-07-030, the Energy Division produces a market price benchmark (MPB) for each forecast year, which includes:
>
> - Value of energy (average price for a 12-month forward strip over 31 days in October);

[8] Id. at 2.
[9] Id. at 70.
[10] Id., Ordering Paragraph 8.

- Value of RA/generation capacity (per MWh adder);
- Line losses (per MWh adjustment).

> Each vintaged portfolio is valued at the MPB to produce a market value for that portfolio. The market value of the portfolio is subtracted from the portfolio cost for each year to determine the ["I]ndifference [A]mount,["] positive or negative. A positive indifference amount indicates that the portfolio cost is above-market for that year, and that contributions from departing customers of that vintage toward these costs are necessary to maintain bundled customer indifference. A negative value for the indifference amount essentially means that bundled customer service benefits from the departure of customers, because energy and capacity produced by the portfolio is more valuable in the market than if sold to departing customers. Pursuant to D.07-05-005, negative indifference amounts are carried forward to offset positive indifference obligations in future years. This eliminates the possibility that departing customers are "paid" to depart the IOU's generation service. Statutory Competition Transition Charge . . . revenue is subtracted from the indifference amount to produce the Power Charge Indifference Adjustment. ....[11]

In short, the methodology includes two calculations for a given set of resources: (i) the Total Portfolio Cost of those resources, and (ii) the value of those resources based on a Market Price Benchmark ("MPB"). In order to achieve bundled customer indifference, both calculations must be reasonable.

Since the MPB methodology was adopted, there have been significant changes in the power market in California that result in a need to revise both aspects of the calculation.[12] Load serving entities ("LSEs"), including the IOUs, ESPs and CCAs, are subject to increasing requirements to procure renewable resources, pursuant to the California Renewable Portfolio Standard ("RPS").[13] There is also now a resource adequacy ("RA") obligation that applies to all LSEs, and the value for capacity agreed to in 2006 has become stale.[14] Moreover, with experience, additional shortcomings have been identified. Most parties agreed that as a result,

[11] Exh. 300 at 18-19 (SCE: Schichtl).

[12] Exh. 800 at 9-10 (CLECA/CMTA: Dr. Barkovich).

[13] Id.

[14] Id.

corrections should be made to the methodology to calculate the NBCs (specifically the PCIA and CTC) as follows: 1) the MPB should be revised to account for the value of RPS compliant resources included in the respective vintaged portfolios of the IOUs; 2) the value for resource adequacy capacity in the MPB should be updated; 3) the MPB should be revised to account for the value of shaping the supply to meet the shape of the load; and 4) the methodology should be clarified to ensure appropriate and consistent exclusion of California Independent System Operator ("CAISO") load-based charges, congestion and short-term purchases from the Total Portfolio Cost.

These corrections are required because the cumulative impact of the flaws is significant and bundled customer indifference is not achieved. Under the current methodology, bundled customers benefit at the expense of customers who depart bundled service. As the panel of Joint Party witnesses testified, the MPB should reflect the forecasted market price of buying/selling a given supply portfolio for a given time period.[15] However, based on publicly available price points from recent transactions, actual market prices are well in excess of the MPB. PG&E's 2010 market transactions for deliveries in 2011 were priced at approximately three times PG&E's 2011 MPB. SCE's 2011 market transactions for deliveries in 2011 are approximately three times SCE's 2011 MPB.[16] Using the current MPB to calculate PG&E's 2011 above-market costs (the Indifference Amount) results in an Indifference Amount that is 37% of the Total Portfolio Cost. Using a more reasonable MPB, that ascribes value to renewable attributes in PG&E's supply portfolio, results in an Indifference Amount that is only 7% of the Total Portfolio Cost. Clearly the current methodology for determining the MPB does not reflect the market price of recent IOU transactions.

[15] Exh. 100 at 12: 20-21 (Joint Parties: Dalessi, Fulmer, Meal).

[16] Exh. 100 at 14:18-23 and 15: 2-16 (Joint Parties: Dalessi, Fulmer, Meal).

A. Recommended changes to market price benchmark (MPB), indifference calculation and PCIA

1. Renewable resource adder for the MPB

The current methodology is flawed because it includes the cost of renewable resources in the IOUs' portfolios' in the Total Portfolio Cost, but the MPB does not account for their market value. The IOUs, the Joint Parties, DRA, and CLECA/CMTA agreed that to correct the flaw, the MPB should be revised to reflect the value of RPS-complaint renewable resources in the IOUs vintaged portfolios.[17] These parties agree that a market value should be determined for RPS-complaint renewable resources in the IOUs' portfolios (a "Green Benchmark"), and that this value should used for RPS-complaint renewable resources for purposes of calculating the MPB. Only one party, witness Reid, disagreed with this approach; his proposal will be discussed later in this brief.

Parties disagreed on the methodology to determine the Green Benchmark. In order to accurately reflect the market value of RPS-compliant renewables, ideally, the Green Benchmark would reflect prices paid by buyers and sellers in recent transactions for delivery of RPS-compliant power in California for the forecast year. Currently, sufficient price data for these transactions are not available. Absent sufficient data on recent market transactions for RPS-compliant resources; three different approaches were proposed to calculate the Green Benchmark:

1. The Joint Parties proposed a methodology that relies on available information regarding the IOUs' current cost to obtain RPS-compliant renewables.[18]

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[17] Exh. 100 at 21: 13-18 (Joint Parties: Dalessi, Fulmer, Meal); Exh. 300 at 25: 21-23, 26: 1-26 and 27: 1-15 (SCE: Schichtl); Exh. 400 at 1-12:21-30 (PG&E: Barry); Exh. 501 at CF-5: 21-26 (SDG&E: Fang); Exh. 600 at 1: 24-26 (DRA: Ouyang); Exh. 800 at 11-12 (CLECA/CMTA: Dr. Barkovich).

[18] Exh. 100 at 24: 17-33 (Joint Parties: Dalessi, Fulmer, Meal).

2. SCE and SDG&E proposed a methodology that relies on data compiled by the Department of Energy's ("DOE") National Renewable Energy Laboratory ("NREL") that reflects premiums paid by retail energy consumers in the market and self-reported by utilities and other energy service providers.[19]

3. PG&E proposed use of "to-be-developed-and-identified" transparent, published market indices of California tradable renewable energy credits ("TRECS").[20]

Several parties (SCE, DRA and PG&E) suggested that, absent agreement on a methodology, a Green Benchmark could be set by negotiation or by the Commission.[21] CLECA/CMTA proposed a variation on the Joint Parties proposal, but without the refinement suggested by the Joint Parties' to ensure that the current market value is based only on the most recent information that is readily available. The record supports the proposal put forward by the Joint Parties as the most reasonable proxy for the market value of RPS-compliant renewables in the IOUs' vintaged portfolios and the best balance between accuracy and feasibility of implementation.

a. The Joint Parties' Proposal is the Best Alternative to Value Renewables in the Current Circumstances

The Joint Parties proposed valuing RPS-compliant renewables using an average of the forecasted cost of renewables built or contracted for by the IOUs that commenced or are projected to commence delivery during the year in question and the prior year.[22] Thus, for

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[19] Exh. 300 at 26: 11-26 and 27: 1-15 (SCE: Schichtl); Exh. 501 at CF-5: 21-26 (SDG&E: Fang).

[20] Exh. 400 at 1-12:32-33 and 1-13: 1-2 (PG&E: Barry).

[21] Exh. 301 at 11: 13-22, 12: 1-21, and 13: 1-6 (SCE: Schichtl); Exh. 400 at 1-13:20-24 (PG&E: Barry); Exh.601: 7: 8-19 (DRA: Ouyang).

[22] Exh. 100 at 24;12-15 (Joint Parties: Dalessi, Fulmer, Meal).

example, for purposes of calculating the MPB in 2011, the value of renewables in each IOU vintaged generation portfolio would be established as follows:

1. Each utility would identify all RPS-compliant resources that began delivery in year 2010 and those projected in their ERRA forecast applications to begin delivery in 2011. This would include both contracts and IOU-owned resources.
2. The IOUs would identify the projected costs of energy produced by each of these resources in 2011.
3. IOUs would provide these data (costs in dollars and volumes in MWh) to the Energy Division.
4. The Energy Division would then calculate the average cost of power from these resources in 2011 by summing up all the costs from all three IOUs and dividing by the sum of all the MWhs from all three IOUs.[23]

This average value would be the Green Benchmark used to value the RPS-compliant renewable resources in each of the IOUs' vintaged portfolios. In their reply testimony, the Joint Party witnesses clarified that if the MPB is otherwise adjusted for capacity, the Green Benchmark should be adjusted to subtract the value of capacity provided by those resources, in order to prevent double counting of capacity.[24]

There are numerous advantages to the proposal of the Joint Parties. First, the methodology proposed by the Joint Parties to establish the Green Benchmark uses a large, diverse data set of prices for relevant RPS-eligible resources from recent market transactions. Second, the methodology is relatively easy to implement as it uses information that is currently compiled and available to the Energy Division. Finally, given that currently and for the next

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[23] Exh. 100 at 24-25 (Joint Parties: Dalessi, Fulmer, Meal).

[24] Exh. 101 at 11-12 (Joint Parties: Dalessi, Fulmer, Meal).

several years there is little likelihood IOUs will have to sell any "excess" RPS-compliant renewables resulting from departing load, the methodology appropriately relies on IOU cost and price data.

The Joint Parties' proposal is the only proposal that represents a market price for the product in question. The product being valued is California-delivered RPS-compliant wholesale supply. The Joint Parties' proposal bases the Green Benchmark on the costs of IOU procurements of this product. The methodology uses a subset of this cost data from resources that are in their first or second year of deliveries and thus reflects current market prices for the correct product. Proposals by other parties either do not value the right product, or do not value current transactions, or both.

Further, the Joint Parties' proposed methodology relies on a robust set of market data, as it uses a large amount of relevant available data. IOUs represent 88% of the load regulated by the CPUC that is subject to the RPS requirement,[25] and, given the recent passage of SBX1-2, 68% of the load subject to the RPS requirement.[26] The IOUs thus comprise a considerable sample of the market.[27] As is discussed below, the DOE data used by SCE/SDG&E is simply irrelevant for purposes of valuing California RPS-compliant supply, as that data relates to a different product. Given the limitations on the use of TRECs adopted by the Commission and the additional limitations set forth in SBX 1 2, the proposal put forward by PG&E represents a much smaller and skewed segment of the market.[28]

[25] Exh. 100 at 25: 2-4 (Joint Parties: Dalessi, Fulmer, Meal).

[26] See Exh. 105 (Joint Parties: Fulmer).

[27] RT at 57:9-17 (Joint Parties; Fulmer).

[28] Section 22, SBX1 2 (2011-2012 Session)(SBX1 2 creates three categories of products that can be used to meet RPS requirements: bundled products; firmed and shaped products, and a third residual category of products that includes unbundled renewable energy credits. The Commission's decision on TRECs (D.11-01-025) defined both firmed and shaped products and unbundled RECs as TRECs. SBX1 2 initially allows use of firmed and shaped

Another advantage of using IOU data is that it will reflect the full range of RPS-compliant renewable resources available in the market including IOU-owned resources and resources that the IOUs purchase through contracts.[29] IOU procurement of RPS-compliant renewable resources includes a wide variety of types of renewable resources, ownership structures, and term of commitments. Wind, solar, biomass, and qualifying small hydroelectric projects, are included as well as unbundled TRECs. The Joint Parties proposed Green Benchmark would include all these resources.

Further, the approach proposed by the Joint Parties is relatively simple to implement since it relies on data that the IOUs must already compile and file with the Commission annually in their Energy Resource Recovery Account ("ERRA") proceedings.[30] In order to maintain the confidentiality of data the IOUs claim is confidential, the Energy Division would have to compile the data from the respective IOU filings to develop the Green Benchmark, which is consistent with the current practice of having the Energy Division calculate the MPB.

Finally, with the departure of load, an IOU may avoid the next planned increment of RPS-compliant resource procurement and bundled customers avoid having to pay for commensurate additional RPS-compliant renewable purchases by an IOU.[31] IOUs can also bank excess RPS-eligible renewables from one year for credit in a future year, and avoid the need for a subsequent purchase.[32] Thus, what IOUs are currently paying for RPS-renewable commitments

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products for up to 50% of the RPS requirement, but decreases the limit on these to no more than 25% by 2017. The third category of products which includes unbundled RECs remains limited to no more than 25% initially, ramping down to no more than 10% in 2017. Accordingly, there are now three types of products that can be used to meet RPS requirements, two of these with important restrictions. Moreover, the restrictions in SBX1 2 do not sunset.)

[29] See e,g, Exh. 304, response to question 1 c) (SCE:Schichtl); Exh. 416, response to question 2 c)(PG&E: Barry); Exh. 507, response to question 2 c)(SDG&E: Fang).

[30] Exh. 100 at 24: 5-11 and 26: 7-13 (Joint Parties: Dalessi, Fulmer, Meal).

[31] Exh. 101 at 10: 20-23 (Joint Parties: Dalessi, Fulmer, Meal).

[32] D.06-10-050, Ordering Paragraph 2; RT at 54: 10-11 (Joint Parties: Fulmer).

is particularly relevant since the effect of departing load is to allow the IOUs to avoid subsequent purchases. This analysis is particularly pertinent over the coming nine years, when the percentage of load that must be met by RPS-compliant renewables will grow from the current 20 percent to 33 percent in 2020. [33] Absent the departure of load, IOUs would indeed have to continue to add increments of RPS compliant resources – the IOUs' recent cost of RPS-compliant supply is a reasonable proxy for the market value of the next procurement of RPS-compliant supply that will be avoided as load departs.

A number of issues were raised during the hearings with respect to the approach recommended by the Joint Parties, including the potential for double counting capacity, the fact that IOUs are encouraged to contract with or develop new resources, the fact that agreements may be signed years before a project commences delivery and the concern that the data from the three IOUs is averaged. These issues either have been, or can be, addressed.

First, some parties expressed concern that use of the methodology proposed by the Joint Parties to calculate the Green Benchmark could result in double counting the capacity value of renewable resources. However, the Joint Parties suggested a refinement to the proposed methodology to eliminate from the price any value for capacity in order to avoid double counting.[34] During the hearings, SCE witness Schichtl opined that the correction proposed by the Joint Parties would address the concern.[35]

Second, SCE expressed the concern that "IOUs' portfolios have significantly higher percentages of new renewable resources than ESPs and CCAs. IOUs also have restrictions on contracting that do not apply to ESPs or CCAs, which tends to restrict what IOUs can do to meet

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[33] California Public Utilities Code Section 399.15, as amended in SBX1 2 (session 2011-2012).

[34] Exh. 101 at 11-12 (Joint Parties: Dalessi, Fulmer, Meal).

[35] RT at 82: 26-28 and 83: 1-5 (SCE:Schichtl).

RPS. Thus, the inclusion of ESP and CCA cost data could be expected to lower any perceived 'market value' established by use of IOU-only cost data."[36] As explained above, currently, with RPS requirements increasing until 2020, the impact of departing load is to eliminate the need for an IOU to enter into a future RPS-compliant resource commitment. Recent IOU costs for RPS-compliant renewables represent the most relevant information available about the likely cost of the next increment of RPS-compliant renewables procurement. Hence, it is the most accurate reflection of the value to bundled customers of having RPS-compliant renewable resources freed up for their benefit by the departure of load.

Third, SCE raised the concern that projects commencing service in a given year could have been contracted for several years ago when market conditions differed.[37] While it is possible that older transactions could be included in the data that are used to calculate the Green Benchmark as proposed by the Joint Parties, this would be true only for commitments with long lead times. In its rebuttal testimony, SCE recommended "using data from the IOUs' most current RFIs or RFPs."[38] This solution creates problems of its own. The prices from the most recent RFIs and RFPs will reflect prices for projects that are not yet delivering power, and some of these projects may never come on line.[39] Lower priced projects in particular may never come on line if the aggressive price bid turns out to be insufficient to support project development. Moreover, IOU developed renewables would never be priced in RFI or RFP processes. Thus, on balance, the proposal put forward by the Joint Parties represents the best representation of current market prices that relies on readily available data.

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[36] Exh. 301 at 13: 1-6 (SCE: Schichtl).

[37] See e.g. Exh. 301 at 11: 2-5 (SCE: Schichtl).

[38] Exh. 301 at 12: 14-15 (SCE: Schichtl).

[39] RFI bids may not even be binding.

Further, the approach put forward by the Joint Parties fairly balances using data from recent purchases with other considerations. The Joint Parties proposed using resources expected to commence delivery or having commenced delivery in the upcoming or most recent past year in order to address the reality that new generating resources are not added in a smooth fashion.[40] As Joint Party witnesses explained, "[a] large resource may come online in one year, and a few smaller ones the next. As such, by using two years of data the Green Benchmark is not unduly influenced by a single larger project, while still maintaining the 'recent' criterion.'"[41] Moreover, as noted above, the Joint Parties sought to present an approach that makes use of information that is already compiled in ERRA proceedings.

Fourth, in cross-examination, SCE raised the concern that the approach suggested by the Joint Parties is not IOU-specific and results in a proxy based on the average cost of RPS-compliant procurements by all three IOUs.[42] While the RPS requirement ramps up and the primary impact of departing load will be to obviate the need for a subsequent purchase by an IOU, it could be appropriate to develop IOU specific Green Benchmarks. The Joint Parties would be open to such an approach provided that its implementation does not delay implementing corrections to the MPB.

In sum, the Joint Parties' proposal for calculation of a Green Benchmark fairly balances accuracy and feasibility and provides a robust proxy for the value to bundled customers of RPS-compliant renewables in the IOU portfolios freed up by the departure of load.

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[40] See e.g. Exh. 100 at 25: 15-18 (Joint Parties: Dalessi, Fulmer, Meal).

[41] Id.

[42] RT at 45-28 (SCE: Ms. Combs questioning of witness Fulmer).

b. Use of a REC Index is Premature

PG&E testified that "with respect to indentifying the proper value for a renewables adder, . . . the best source for obtaining a market value will be from a RECs market, specifically a REC market that represents the value of renewable generation in California."[43] Conceptually, the Joint Parties agree that in the future, an RPS market and related indices could be useful for valuing renewables.[44] However, this alternative is premature for two key reasons: 1) given the significant limits placed on the use of TRECs for purposes of RPS compliance in California, indices of TREC prices will likely understate the value of RPS-compliant renewables in the IOUs portfolio; and 2) indices are not available now for review in this proceeding to evaluate whether they are adequate.

As the Joint Parties' witnesses explained:

> The TREC is unlikely to fully reflect the renewable attribute value of resources in the IOU portfolio and would not be a good basis for the renewable price component of the MPB. The TREC decision essentially creates two classes of renewable purchases for RPS compliance. Purchases of energy bundled with the associated renewable attributes from in-state renewable resources as well as certain out-of-state renewable resources that can be dynamically scheduled with the CAISO are classified as "bundled renewable resources" and qualify for RPS compliance without limitation by load serving entities. Purchases of unbundled renewable attributes or bundled purchases of energy and renewable attributes from other renewables resources that meet the technology qualifications for RPS eligibility can be used for RPS compliance on a limited basis, as they are considered unbundled TRECs and are subject to a usage limitation of 25% of the load serving entity's RPS requirement. The limitation on use of TRECs for RPS compliance will limit the trading and therefore the liquidity of the TREC market, and impede the development in the near term of a robust TREC market index. [45]

Dr. Barkovich concurred:

> the Commission decision cited by PG&E as permitting the use of RECs for compliance with renewable portfolio standard requirements limits the use of

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43 Exh. 400 at 1-13: 4-6 (PG&E: Barry).

44 Exh. 101 at 6: 18-22 (Joint Parties: Dalessi, Fulmer, Meal).

45 Exh. 101 at 7: 1-15 (Joint Parties: Dalessi, Fulmer, Meal).

> RECs for such compliance. Thus, most of the renewable compliance will come from renewable generation contracts, not REC contracts. It is much too soon to be able to determine if the price of unbundled RECs in the market will track what utilities are paying for the renewable attribute in their renewable generation purchases.[46]

This testimony references D.11-01-025, which limited the use of TRECs by IOUs to no more than 25% of their RPS requirement until December 31, 2013. Since this testimony was filed and after the conclusion of the hearings, SBX 1 2 was signed into law, which also restricts use of TRECs. There are now three categories of products that can be used to meet RPS requirements, two of these with important restrictions. Moreover, the restrictions in SBX1 2 do not sunset.[47] It is not certain which of the categories of products created by SBX1 2, PG&E would include in its proposal to use TREC indices. In any event, with the added restrictions set forth in SBX1 2, the concern that indices for TRECs may not adequately reflect the value of renewables in the IOU portfolios has been heightened since the conclusion of the evidentiary hearings.

In addition, there was no TREC market index available for consideration during this proceeding, and opinions about whether and when such indices will develop are speculative at best. PG&E testified that

> an open, transparent, and liquid market for RECs is developing in California as a result of D.11-01-025. Based on informal discussion with brokers familiar with the development of other renewable markets in the United States (U.S.), PG&E expects some brokers will publish TREC indices and make them available to their clients. In fact, one publisher, SNL Financial, currently publishes an index of REC prices throughout the U.S., including REC prices in California. . . . The SNL REC Index could be used as one of the data inputs for determining the value of the renewables adder. PG&E expects that in the next few months, additional

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[46] Exh. 801 at 3 (CLECA/CMTA: Dr. Barkovich).

[47] Section 22, SBX 1 2 (2011-2012 session).

> indices and other data will be available for determining the value of RECs in California.[48]

Notwithstanding this testimony, PG&E did not make a specific proposal for use of existing indices that could be evaluated by other parties. Rather, PG&E witness Pappas noted that "it would take some time for a robust market to develop whereby entities developed a REC index."[49]

The Joint Party witnesses laid out some of the criteria that would have to be evaluated to determine whether any particular REC market index is appropriate for purposes of valuing renewables in the IOUs portfolio as follows:

> what we are pointing out are some of the difficulties in guessing as to what sort of index might develop in the future. And we also describe that the market would have to be sufficiently liquid. There would have to be a very defined product that was comparable to the product being valued in the calculation. And we would need to go through a deliberative process to make sure that the index that develops is fully reflective of the product that is being valued.[50]

PG&E's criteria for determining whether an index would be useful to value RPS-compliant renewables in IOU portfolios are not dissimilar:

> The initial criteria the Commission would use in determining whether a particular index was appropriate for use as a renewable adder in the Market Price Benchmark is whether the TREC price published in the index was for a product that meets the eligibility requirements of the California RPS. Second, the index would need to be sufficiently transparent and robust. The criteria to establish transparency and robustness would be similar to that used for published price indices for other commodities such as natural gas, including sufficient volume and consistent information among market participants. The indices would vary by term and TREC vintage. However, the delivery profile would not be a consideration since TRECs are separate and distinct from the underlying power. The indices would not be differentiated by technology, since the California RPS does not distinguish between renewable technologies.[51]

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[48] Exh. 401 at 16-17 (PG&E: Barry, Pappas).

[49] RT 374: 9-12 (PG&E:Pappas).

[50] RT 40:21-28 and 41: 1-4 (Joint Parties: Meal).

[51] Exh. 413 (PG&E: Pappas).

TRECs are a product that can only be used to meet a limited portion of the California RPS requirements, and consequently, by PG&E's own description, an index of TRECs is not useful to determine the value of all the renewables in the portfolios of the IOUs.[52] In any event, there is no evidence in the record suggesting that the one index which PG&E claims currently exists, meets these criteria. Thus, PG&E's proposal to use TREC market indices to value the renewable attributes in the IOUs portfolios is premature at best.

c. Using Premiums from Voluntary Retail Programs is Not Appropriate to Value the Renewable Attributes of Mandatory RPS-Compliant IOU Purchases

To value renewables in the IOUs' portfolios, SCE and SDG&E propose to use the average premium for voluntary renewable energy purchases in western states that are members of WECC, as reported by the DOE NREL.[53] As Dr. Barkovich explained, this figure "is not a suitable proxy as it captures an entirely different metric. . . . . [and] has nothing to do with a wholesale market premium for renewable generation compared to gas-fired generation."[54] Further as DRA witness Ouyang pointed out, there is insufficient information to determine how much revenue is generated by the voluntary green pricing premiums and how much additional RPS resources are procured as a result and hence to determine the price for each unit of renewable energy that is purchased.[55] In addition, as the Joint Parties witnesses pointed out, "it

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[52] Interestingly PG&E witness Pappas indicated that in some other states, different renewable products have been divided into different classes, each with their own index. RT at 376 1: 6 (PG&E: Pappas). Yet in California where there are now three categories of products available to meet RPS compliance, one unlimited, and the others limited, PG&E proposes to use market indices for the most limited category of products to value all RPS-compliant resources.

[53] Exh. 300 at 26: 16-18 (SCE: Schichtl); as clarified during testimony, RT at 139: 5-18 (SCE, Schichtl); Exh. 501 at CF-5: 22-26 (SDG&E: Fang).

[54] Exh. 801 at 4 (CLECA/CMTA: Dr. Barkovich); see also exh. 101 at 2-3 (Joint Parties: Dalessi, Fulmer, Meal).

[55] RT 710:21-28 and 712: 1-9 (DRA: Ouyang).

is not clear that the database is even current or updated on a regular basis" and "no new programs were listed for 2010."[56]

Moreover, the evidence suggests that the $20/MWh value for renewable attributes that results from using the DOE NREL data is substantially below the value of RPS-compliant renewables in California. Use of this value results in an "all in" market value for renewable resources for 2011 of about $70/MWh (i.e. the Green Benchmark).[57] $70/MWh is substantially below what PG&E is forecasting to pay for its recent renewable commitments in 2011 ($145/MWh), and substantially below the Market Price Referent (ranging from $90/MWh to $125/MWh over the period 2006-2009), while the majority of recently-approved IOU renewable purchase contracts have costs in excess of the Market Price Referent.[58]

Accordingly, the NREL DOE data does not provide a relevant basis to value RPS-compliant renewable attributes in the IOUs portfolios.

d. The Proposal of PG&E and SDG&E to Value Pre-2004 Renewables at the Current Market Price Benchmark is Unfair

PG&E and SDG&E have proposed that any renewable adder be applied only to renewable resources procured or built post 2003.[59] This position was made clear in PG&E and SDG&E responses to discovery.[60] SCE did not take a position on this limitation, and it is in fact unfair.

As the Joint Party witnesses explained,

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[56] Exh. 101 at 3:1-3 (Joint Parties: Dalessi, Fulmer, Meal).

[57] Exh. 101 at 3: 15-20 (Joint Parties: Dalessi, Fulmer, Meal)(explaining that the $20 Green Benchmark would be added to a MPB of about $50 to result in an all in price of about $70/MWh).

[58] Exh. 101 at 3:10-30 (Joint Parties: Dalessi, Fulmer, Meal); see also Exh. 801 at 4-5 (CLECA/CMTA: Dr. Barkovich).

[59] Exh. 400 at 1-13:30-34 (PG&E: Barry).

[60] Exh. 415 (PG&E: Barry); Exh. 507, Answer to question 1.b. (SDG&E: Fang).

> There is broad agreement that the current methodology does not accurately reflect the value of RPS-eligible resources. In order to correct the flaw, both (i) the market price benchmark must reflect the market value of RPS-eligible supplies . . . and (ii) that market value must be compared to the cost of all RPS-eligible volumes in the IOUs' portfolios. . . . To the extent any RPS-eligible volumes are excluded, those RPS volumes will be compared against the system (brown) power benchmark, understating the value of those resources.[61]

SCE's witness Schichtl similarly testified that there is no reason to limit the application of the renewable adder only to post-2003 renewable resources: "Because our proposal was simply to create a weighted average market price benchmark using the percentage of renewable resources in each vintage year and to – and applicable Commission-adopted renewable premium. We saw no reason to exclude them from any particular vintage, or any particular vintage of resources."[62]

PG&E attempted to explain the exclusion by arguing that recognizing the value of renewable attributes in pre-2004 resources, including those resources used to calculate CTC, would result in double counting.[63] As Joint Parties' witnesses testified, no double counting would occur: "No double counting occurs as long as all portfolios are weighted based on RPS-eligible volumes, and the MPB is calculated the same for all portfolios, including for CTC resources."[64] During the hearings, PG&E argued that pre-2004 volumes should be excluded because "the contracts that were signed were signed without any express transfer of the renewable attributes. We do not have ownership of the renewable attributes. . . . We cannot – California RECs cannot be generated based on contracts signed prior to I believe it's 2005. So the proposals in this proceeding were moving towards imputing renewable value to those contracts that quite frankly don't exist."[65] [66]

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[61] Exh. 101 at 9:1-14 (Joint Parties: Dalessi, Fulmer, Meal).

[62] RT 78: 1-8 (SCE; Schichtl); see also exh. 304, response to question 02 a-f (SCE:Schichtl).

[63] Exh. 400 at 1-13:30-34, 1-14:1-14 (PG&E: Barry).

[64] Exh. 101 at 9:20-22 (Joint Parties: Dalessi, Fulmer, Meal).

[65] RT 365: 23-28 and 366: 3-9 (PG&E: Pappas).

This response is unpersuasive. All the IOUs confirmed that they claim RPS compliance credit for renewables procured before 2004.[67] Their requirement to procure additional RPS-compliant renewable resources is reduced one for one, for every MWh of pre 2004 renewable resources generated in their portfolio. In this context, it is absurd to claim that the renewable attributes associated with pre-2004 renewables in the IOUs' portfolios are of no value to the IOUs and bundled customers. Even if it were true that the IOUs cannot sell these renewable attributes, they certainly benefit from them.[68]

Moreover, the volumes in question are substantial, so it is critical to ensure that these volumes are treated appropriately in the methodology. In 2010, the volume of RPS-eligible procurement from pre-2004 contracts for which the IOUs obtained RPS-compliance credit is 9,767,023 out of 14,548,328 MWh for SCE (well over half); 5,564,726 out of 13,760,286 MWh for PG&E (well over one third)[69]; and 388,938 out of 1,940129 MWh for SDG&E (about one fifth).[70] The exemption proposed by PG&E and SDG&E would have the effect of substantially reducing the volume of energy from renewable resources for which the value of renewable attributes is recognized. It is not supported by the IOU with the largest proportion of pre 2004 renewables, SCE. The proposal is unfair as it significantly understates the value of renewable resources in each of the IOUs portfolios, and should be rejected.

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[66] This explanation was only provided during evidentiary hearings in response to questioning, after the Joint Party witnesses testified. Accordingly, there was no opportunity to introduce testimony in response.

[67] Exh. 304, response to question 02 a-f (SCE:Schichtl); see also RT at 75: 7-12 (SCE:Schichtl); Exh. 416 (PG&E: Pappas); see also RT at 367: 26-28 (PG&E: Pappas); Exh. 507, response to question 2, a-f (SDG&E: Fang).

[68] There is no suggestion in the record that departing load going to CCAs or ESPs comes anywhere close to the levels where the IOUs would have to sell pre-2004 volumes to avoid an excess of RPS-compliant renewable resources.

[69] PG&E testified that these numbers may be revised slightly as final numbers are tallied. RT at 363: 2-13 (PG&E: Pappas).

[70] Exh, 416 (PG&E: Pappas); Exh. 304 response to question 2 a-f (SCE: Schlichtl); Exh.507 response to question 2 a-f (SDG&E: Fang).

2. Generation and/or load profile modifications for the MPB

a. The bundled load profile should be used to value the IOUs' supply portfolios

The Joint Parties' opening testimony recommends that the MPB should be adjusted so that it comprises a shaped energy price as opposed to the existing methodology which calculates a flat or baseload energy price as the energy component.[71] The current MPB is based on an implicit assumption that the IOU supply portfolio serves a flatter load profile than it actually does and therefore creates an artificially low market value and artificially high Indifference Amount, and in turn, artificially high PCIA and CTC. Because the IOU supply portfolio is constructed to serve the load of bundled service customers as that load varies from hour-to-hour, the load shape of bundled service customers should be used in valuing the IOUs' supply portfolios.

This was explained more fully during the cross-examination of the Joint Parties panel, when Joint Parties witness Meal was asked and answered the following question:

> Q Does the existing market price benchmark accurately forecast what an IOU could expect to receive if it sold energy in the market today?
>
> A The existing methodology uses a very specific market price benchmark that reflects just a 24 by 7 flat load profile brown power supply. And that does not currently reflect the full value of what a willing buyer and a willing seller would pay for the attributes that are being valued. So as our testimony details, several elements of the utility supply portfolio are excluded when their values are using the current price benchmark.[72]

While the IOUs initially suggested use of the generation load profile of their supply portfolio as the basis for adjusting the MPB, Joint Parties witness Dalessi explained during cross-examination why the use of the bundled load profile is preferable, as follows:

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[71] Exh. 101 at 28: 13-33 (Joint Parties: Dalessi, Fulmer, Meal).

[72] RT at 38:11-25 (Joint Parties: Meal).

> The bundled profile -- you know, the utilities proposed using the generation profile. And so if you think of the bundled load profile as sort of a proxy for the generation profile because the resources can be sold to the market at peak times. They'll be dispatched during peak times and yield higher prices than if they were just dispatched 24/7, which is what the current market price benchmark in effect assumes, that it's a flat-based load price. So, you could using the generation profile. But we proposed to use the load profile simply because it's a bit more of a transparent number and the third-party market participants such as our clients can reasonably approximate the load profile and that really can't be done for generation load profile.[73]

SCE's witness Schichtl agreed with this approach.[74]

b. The shaped energy price can be calculated with a relatively simple modification to the current MPB calculation

Under the current methodology, forward prices for peak energy and for off-peak energy are used to calculate a forward baseload energy price. This is accomplished by calculating a weighted average of the peak and off-peak forward energy prices, using the number of peak and off-peak hours in the year, respectively, as the weighting factors.[75] The Joint Parties have proposed a simple modification to the current MPB methodology that should be adopted by the Commission. The weighting factors for a shaped energy price should be calculated based on the annual forecast of energy sales to bundled customers during both peak and off-peak periods of the year. An illustrative calculation of a shaped energy price is shown in the following example taken from the Joint Parties' opening testimony:[76]

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[73] RT at 64:11-28 and 65:1 (Joint Parties: Dalessi).

[74] Exh. 301 at 7: 7-15 (SCE: Schichtl).

[75] Exh. 101 at 29: 1-8 (Joint Parties: Dalessi, Fulmer, Meal)

[76] Exh. 101 at 29:23-27 (Joint Parties: Dalessi, Fulmer, Meal).

Period [Col. 1]	Price ($/MWh) [Col. 2]	MWh [Col. 3]	Weighting Factor [Col. 4]
On-peak	$40.00	50,000,000	0.667
Off-peak	$28.00	25,000,000	0.333
Shaped Price	$36.00		

The actual shaping factors should ideally be based on the hourly load profile used by each utility for its sales and cost forecasts provided in its annual ERRA proceeding.

There are several advantages to this approach. First and foremost, its adoption will cause the MPB to accurately reflect the delivery profile of the supply portfolio and thereby more accurately provide for bundled customer indifference. Second, an advantage of using the utility's bundled load profile for the weighting factors is that the shaped energy price for "brown" power would be the same for all PCIA vintages and for the CTC portfolio. Third, the inputs required for calculating the shaped energy price are readily available since each utility's bundled hourly load profile is used to derive the utility's fuel and purchase power expense forecast presented in their respective annual ERRA proceeding.

However, at least some of the data in the ERRA proceeding are redacted due to utility assertions of confidentiality. Therefore, the Joint Parties recommend that the Energy Division could validate the load profile weighting calculation, or alternatively that the Commission adopt SCE's recommendation to use the latest publicly available bundled load profile to derive the load weighting factors.[77]

[77] Exh. 301at 7: 7-15 (SCE: Schichtl).

c. Vintaging is not Required

DRA argued that a different on- and off-peak weight for each PCIA vintage would be needed. Witness Dalessi rebutted this suggestion on cross, as follows:

> So I think theoretically, it probably could make sense or would make sense to use a different profile for the different vintage. I just don't think it's worth the effort because even when you compare the Joint Parties' proposal to using the bundled load profile to the utilities' proposals to use the generation profile, there's not a whole lot of difference between the weighting factors that result from those two different methodologies. So I just don't see that going -- doing the extra analysis to try and come up with different profiles for different vintages is going to change the numbers sufficient to warrant the effort. [78]

Witness Dalessi further explained that: "I wouldn't expect that the generation resources, that the actual generation profiles of those resources across the vintages are going to be radically different enough to change the resulting weighting factors to a significant degree."[79] And further:

> Q . . . Could you give us a better understanding of how much effort it is to do these different calculations by vintage?
>
> A Well, from the Joint Parties' perspective, we would -- we're proposing to use a single load profile. So it really doesn't make sense to use a different load profile for different vintages. I think that comes into play if you're looking at the utility proposal to use a generation profile, because then each generation vintage could conceivably have its own production profile. I don't know how much effort that would be. That's not something that we have visibility to. It's really the utilities' production costs simulation modeling that would result in those numbers.[80]

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[78] RT at 65:16-28 and 66: 1-2 (Joint Parties: Dalessi).

[79] RT at 66:15-20 (Joint Parties: Dalessi).

[80] RT at 66: and 67:1-11 (SCE: Schichtl).

SCE witness Schichtl also agreed that a non-vintaged, non-confidential historic bundled customer load profile could be used to adjust the MPB and that the bundled load profiles and generation load profiles are not expected to differ substantially.[81]

3. Revised capacity adder for the MPB

As noted by SCE in its rebuttal testimony, several parties are in agreement that an update to the capacity adder is necessary:

> Parties generally agree that an appropriate update to the existing capacity adder incorporated in the MPB should be based on the publicly available capacity procurement mechanism (CPM), which serves as the backstop mechanism for capacity at the CAISO. SCE agrees so long as the CPM payment continues to reflect the "going-forward" fixed costs of a simple cycle combustion turbine (CT) as defined by the California Energy Commission (CEC), as is currently the case.[82]

Similarly, SDG&E witness Fang recommended that the Commission:

> Adopt a method of regularly updating the generation capacity adder; specifically, base the generation capacity adder on the price set in the California Independent System Operator's ("CAISO") Interim Capacity Procurement Mechanism ("ICPM") (to be superseded by Capacity Procurement Mechanism ("CPM")) in effect when the annual MPB is calculated.[83]

The IOUs' joint workshop proposal would establish the capacity value of the utility portfolio based on the total "Net Qualifying Capacity" ("NQC") of all generation resources (utility owned and power purchases) in the utility portfolio and the price for capacity established by the CAISO for the CPM, as that price is modified and approved by FERC from time to time.[84] The capacity value would vary for each portfolio vintage, as the NQC would reflect the specific resources included in each vintage. Specifically, the NQC of each vintaged supply portfolio and the currently approved CPM should be used to value the capacity of the portfolio. The supply

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[81] Exh. 301 at 7: 12-19 (SCE:Schichtl); and RT at 80:9-28 and 81:1-9 (SCE:Schichtl).
[82] Exh. 301 at 8:14-19 (footnotes omitted)(SCE: Schichtl).
[83] Exh.501 at CF-5: 11-16 (SDG&E: Fang).
[84] See presentation #6 attached to the Workshop Report of the Joint Parties, January 14, 2011.

portfolio NQC should be the sum of the individual NQC of all resources included in each vintaged supply portfolio, as these vary by vintage, and these data should be made available for verification by the Energy Division.

At the time of the workshop, the California Independent System Operator ("CAISO") had filed a proposal for the CPM with the Federal Energy Regulatory Commission ("FERC"). The CAISO's filing priced the CPM based on the going forward costs of a hypothetical 50 MW simple-cycle, gas-fired unit built by a merchant generator, determined based on comprehensive studies conducted by the California Energy Commission, and a 10 percent adder.[85] Based on this methodology, the price for CPM was proposed at $55/kW-year.[86] At the time FERC had not acted on the proposal.

The Joint Parties opening testimony[87] observed that the current market price benchmark includes capacity adders that were the result of a settlement among parties in 2006, when the resource adequacy program was just getting underway. It is necessary in this relook at the MPB methodology to update these proxy capacity values with more current information. The Joint Parties agreed with the approach described above that was proposed by the IOUs during the workshops.

After the preparation of written testimony, a few days before the evidentiary hearings, FERC issued an order expressing concern about the methodology proposed to establish the CMP price and establishing a technical conference to address this issue.[88] In particular, FERC stated:

> The Commission is concerned that CAISO's proposal to pay going forward costs may create the potential for distorted pricing signals and deny resources a reasonable

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[85] 134 FERC ¶ 61,211 (March 17, 2011) at 6.

[86] Id.

[87] Exh. 100 at 30: 25-31 and 31: 1-13 (Joint Parties: Meal, Dalessi, Fulmer).

[88] 134 FERC ¶ 61,211 (March 17, 2011) at 19-21.

> opportunity to recover fixed costs. CAISO, in this filing, has not explained how the use of going-forward costs for CPM compensation will provide incentives or revenue sufficiency for resources to perform long-term maintenance or make improvements that may be necessary to satisfy new environmental requirements or address reliability needs associated with renewable resource integration.
>
> . . . .
>
> Furthermore, and significantly, we find the continuation of a fixed going-forward cost price has not been shown to be just and reasonable because the likelihood that market conditions, which can affect the price of capacity, will fluctuate over time.
>
> . . . .
>
> At the technical conference, staff will seek additional information on CPM compensation methodologies that would provide, at a minimum, a meaningful opportunity for CPM resources to recover additional fixed costs. The technical conference will explore options for structuring CPM compensation that would take into account such things a future variances in price and potential shortages of supply.[89]

Thus, FERC found that the proposed methodology for the CPM might be unjust and unreasonable because it failed to provide for legitimate going forward costs (it is too low) and will not adequately reflect changing market conditions such as scarce supply.

Given the uncertainty about CPM going forward, the Joint Parties recommend that the Commission adopt a revised capacity price that uses the methodology proposed by the IOUs, but with the caveat the proposed CPM value of $55/kW-year be used until further action by the CPUC. This number is more current than the 2006 information that supported the existing adder at the time it was adopted, and is based on extensive CEC studies on the going-forward price of a gas-fired plant. Upon issuance of a final FERC order on the CPM, the CPUC should give the parties a limited opportunity to file further comments on whether and how the final FERC order should result in a change to the updated capacity adder.

[89] 134 FERC ¶ 61,211 (March 17, 2011) at 20.

4. CAISO load-based costs

There was general agreement among the Parties that all CAISO load-based charges should be excluded from the Total Portfolio Costs of the IOUs, for purposes of calculating PCIA and CTC.[90] This is because CAISO load-based charges will not be incurred on behalf of departing load after its departure. Similarly, the IOUs agreed that the Total Portfolio Cost either does not now, or should not in the future, include congestion costs.[91]

Initially, PG&E raised questions about the feasibility of estimating CAISO non-load-based charges separately from load-based charges, and suggested excluding all CAISO charges. However, during hearings PG&E witness Barry stated that PG&E would be amenable to estimating CAISO non-load-based charges and excluding only estimated CAISO load-based charges.[92]

While there is general agreement in principle, implementation will require some monitoring. As PG&E explained on the stand, there are many CAISO charge types, some of these exclusive to PG&E,[93] and both PG&E and SCE admitted on the stand that they have not in the past forecasted load-based CAISO charges, separate from non-load-based CAISO charges.[94] Accordingly, the Joint Parties agree with DRA's recommendation that the Commission should establish clear guidelines for distinguishing load-related CAISO cost components and congestion charges to ensure that they are removed from the Total Portfolio Cost.[95] The Commission should

[90] Exh. 100 at 32: 16-20 (Joint Parties: Meal, Dalessi, Fulmer); Exh. 300 at 28: 21-24 and 29: 1-2 (SCE: Schichtl); RT at 359: 11-13 (PG&E: Barry); Exh. 501 at CF-6: 3-5 (SDG&E: Fang); Exh. 600 at 6: 18-20 (DRA: Ouyang); Exh. 800 at 12, A-17 (CLECA/CMTA: Dr. Barkovich).

[91] RT at 85: 17-26 (SCE: Schichtl); RT at 359: 18-21 (PG&E: Barry); RT at 703: 11-19 (SDG&E: Choi).

[92] RT 359: 11-13 (PG&E: Barry).

[93] Exh. 412 (PG&E: Barry); RT at 358: 1-26 (PG&E: Barry).

[94] See Exh. 412 (PG&E: Barry); RT at 84: 7-10 (SCE: Schichtl).

[95] Exh. 101 at 18:1-5 (Joint Parties: Dalessi, Fulmer, Meal); Exh. 600 at 6: 21-25 (DRA: Ouyang).

1) state in its decision the general principle that CAISO load-based charges and congestion charges should be excluded from the Total Portfolio Cost, and 2) at the time the IOUs revise the NBCs in accordance with the decision, require them to demonstrate that they have accurately forecasted non-load based CAISO charges, and fully excluded from their Total Portfolio Cost all load-based CAISO charges and congestion costs.

5. Short-term purchases

Parties opining on the matter also generally agreed that short-term purchases should be excluded from the Total Portfolio Cost.[96] PG&E testified that excluding short-term purchases from the Total Portfolio Cost is "a direct result of implementing the directives adopted in D.06-07-030, which in turn are more fully, articulated in the February 1, 2006, Working Group Report, which was a part of the record in the Direct Access Suspension Proceeding, Rulemaking 02-01-011."[97] DRA's testimony clarifies that by short-term purchases, parties meant purchases of less than one year.[98] This clarification should be included in the Commission's decision to avoid confusion and inconsistencies going forward.

B. Other proposals for changes to MPB, indifference calculation, PCIA or ongoing CTC

PG&E and SDG&E oppose applying some (in the case of PG&E) or all (in the case of SDG&E) of the corrections to the MPB used to calculate the PCIA discussed above, to the MPB used to calculate CTC. These positions to forego reforms to the CTC are not supported by the record and should be rejected. The PCIA and CTC are both surcharges intended to collect the above-market costs (or credit the below-market costs) associated with specific generation

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[96] Exh. 300 at 29: 16-18 (SCE: Schichtl); Exh. 401 at 22: 6-12 (PG&E: Barry); Exh. 501 at CF-6: 6-7 (SDG&E: Fang); Exh. 601 at 3:28-19 and 4: 1-2 (DRA, Ouyang).

[97] Exh. 401 at 22: 6-12 (PG&E: Barry).

[98] Exh. 600 at 6: 27-30 and 7:1-6 (DRA: Ouyang).

commitments (specific supply portfolios) made by the IOUs. The CTC represents the above-(or below-) market costs of a specific subset of supply. The PCIA covers all other eligible supplies assigned to load according to its vintage. Under the current methodology, the Indifference Amount is determined for the total portfolio of resources (PCIA and CTC) using the MPB. Any above market costs associated with the CTC resources are determined using the same MPB that is used for determining the Indifference Amount, and the CTC cost are subtracted from the Indifference Amount to determine the PCIA revenue requirement. So the Total Portfolio of resources, both the PCIA portion and the CTC portion, are all valued using the same MPB.[99]

Thus, the adjustments to the MPB discussed above should be made for purposes of calculating both PCIA and CTC. The distortions that give rise to the need to modify the MPB for purposes of calculating the PCIA apply equally in the context of the calculation of CTC.[100] SCE supports the view that changes adopted for the calculation of the MPB should apply for purposes of calculating CTC.[101] As SCE explained in response to a City and County of San Francisco data request "D.06-07-030 provides that CTC be determined using an MPB consistent with that used to determine the indifference amount."[102]

PG&E contends that the adjustment to reflect the value of renewable attributes in the IOUs' portfolios should be not be made for purposes of calculating CTC.[103] PG&E premises this position on the fact that CTC resources are pre-1996 vintage and its position described above,

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[99] Exh. 100 at 7: 1-19 (Joint Parties: Dalessi, Fulmer, Meal).

[100] See Exh. 100 at 8-18 (Joint Parties: Dalessi, Fulmer, Meal).

[101] Exh. 304, response to question 1.b) (SCE: Schichtl).

[102] Id.

[103] Exh. 415, response to question 1.b. (PG&E: Barry).

that no value should be attributed to renewable resources procured before 2004.[104] Since this argument is addressed above, it will not be discussed further here. PG&E does clarify that other applicable changes to the MPB such as recognizing the value of shaping resources to load, and updating the capacity value should be adopted for purposes of calculating CTC.[105] The changes related to excluding CAISO load-based and congestion charges, and short-term purchases, are not applicable because these costs are not included for purposes of calculating CTC.[106]

SDG&E inexplicably argues that none of the changes to the MPB proposed for purposes of calculating the PCIA should apply in the context of calculating CTC. SDG&E contends: "SDG&E does not believe that the revised MPB methodology should be used to determine CTC revenue requirements. The revision to the MPB methodology for determining the indifference amount is intended to provide a better estimation of bundled customer indifference. This reasoning does not extend to the CTC revenue requirement determination."[107] With respect to use of an adjustment to reflect the value of renewables, SDG&E contends "The Green Benchmark adjustment for the determination of Ongoing CTC revenue requirement would not be appropriate since these requirements were established prior to the implementation of RPS mandates."[108] These claims are nonsensical. With respect to the adder to recognize the value of renewables, as discussed earlier, the IOUs obtain RPS credit for renewables procured prior to implementation of RPS mandates. Thus, these resources, the above market costs of which

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[104] Id.

[105] Id.

[106] Exh. 415, response to question 1.c. (PG&E: Barry).

[107] Exh. 507, response to question 1.b), (SDG&E: Fang).

[108] Exh. 507, response to question 1.d), (SDG&E: Fang).

departing load customers pay, have RPS value. A failure to recognize the value in the MPB for CTC results in an unjustified shifting of the benefits exclusively to bundled customers, and of the costs to departing load.

SDG&E's first statement implies that the indifference principle is inapplicable for purposes of calculating CTC. This contention is simply wrong. For example, in D.06-07-030, the Commission applied the indifference principle in addressing the calculation of CTC as follows: "Specifically, we required that bundled customers be indifferent due to customers migrating from bundled to DA load, and that there be no cost shifting. To prevent cost shifting, we adopted a methodology in D.02-11-022 to capture the relevant costs in the form of a CRS to be assessed on designated DA load. The CRS incorporates, among other elements, a California Department of Water Resources (DWR) power charge and the ongoing competition transition charge (CTC)."[109]

Thus, the adjustments proposed for the MPB should be used for purposes of calculating both PCIA and CTC.

C. Other proposals for changes to the indifference calculation

One party only, witness Reid, proposed that instead of adjusting the MPB to incorporate the value of renewable attributes in the IOUs portfolios, CCAs and ESPs should be given credit for the renewable attributes they pay for in NBCs.[110] Witness Reid's rationale appeared to be that this would obviate the need for bundled customers to pay for the renewable attributes they retain.[111]

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[109] D.06-07-030 at 3.

[110] Exh. 700 at 12: 1-12 (Reid: Reid). Witness Reid ascribes this position to The Utility Reform Network (TURN). While TURN presented this approach as an alternative during the workshops preceding the hearings, TURN did not participate during evidentiary hearings and this proposal was put forward during the hearings only by witness Reid.

[111] Id.

The Joint Parties object to witness Reid's proposal. As Joint Parties' witnesses explained:

> One of the problems with this approach is that it reduces the ability of a competitive provider to manage a resource portfolio that is optimized to meet the specific demands of its customer base. Competitive providers may have specific renewable resource technology or resource locational preferences that appeal to their customers or otherwise fit well within their supply portfolio, and an allocation of RPS resources from the IOU portfolio may be inconsistent with those preferences. In short, customers who choose to depart utility service are simply not looking to have their supply come from the utility portfolio. [112]

As Dr. Barkovich explained succinctly, "this concept undermines the potential benefit of retail competition, which is to give DA and CCA customer the opportunity to receive power from a different portfolio, as long as it meets state and Commission procurement requirements."[113]

Moreover, implementing this approach will be complex, and raises contentious questions about the fair allocation of renewable attributes from various categories of resources, including bundled, firmed and shaped, and TREC resources.[114] It does not make sense to grapple with these issues in the context of a proposal that has such limited support among the parties.

D. Other proposals for changes to the PCIA

1. PG&E's Proposal to Eliminate Negative PCIA

a. Introduction

SCE rightly frames the importance of the so-called bundled customer indifference principle by stating that "[t]he indifference principle has stood since [D.02-03-055], and must remain the guiding principle above any other considerations."[115] The Commission has variously defined bundled customer indifference, but perhaps never so succinctly as follows: "bundled

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[112] Exh. 101 at 14:5-12 (Joint Parties: Dalessi, Fulmer, Meal); see also exh. 601 at 12: 16-22 (DRA: Ouyang).

[113] Exh. 801 at 10 (CLECA/CMTA: Dr. Barkovich).

[114] Exh. 101 at 12: 31-32 and 13: 1-27 (Joint Parties: Dalessi, Fulmer, Meal).

[115] Exh. 300 at 18:17-18 (SCE: Schichtl). *See also id.* at 17:9-10 ("The principle of bundled service customer indifference must be preserved.").

customer indifference means that bundled customers should be no worse off nor should they be any better off due to departing loads."[116]

Under the Commission's past decisions, the so-called Indifference Amount is determined on a total portfolio basis in order to achieve bundled customer indifference.[117] The Indifference Amount consists of two elements: CTC and PCIA. The CTC is determined first, and then the PCIA is determined on a residual basis: "PCIA is the difference between the indifference amount and the CTC."[118] "So a negative PCIA would result when CTC is higher than the indifference amount."[119] A negative PCIA essentially offsets the CTC.[120]

In its testimony, PG&E criticizes the Commission's past application of the bundled customer indifference principle, arguing that the Commission should not have previously allowed a negative PCIA to offset the CTC. PG&E acknowledges that "Decision 06-07-030, which modified the Indifference calculation, also modified the constraints on the Indifference Charge (*e.g.*, PCIA) such that it could be negative up to the level of the Ongoing CTC."[121] However, according to PG&E, this approach was not "thoroughly examined" by the Commission, and should be re-visited.[122] PG&E's chief complaint is that '[t]he PCIA should not

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[116] D.08-09-012 at 45. *See also* Exh. 800 at 5 (CLECA/CMTA: Dr. Barkovich) ("Bundled customer rates should not go up (or down) because DA or CCA load departs….").

[117] *See* Exh. 800 at 6-8 (CLECA/CMTA: Dr. Barkovich) , referencing D.02-03-055, D.02-11-022 and D.06-07-030. *See also* Exh. 300 at 16 (SCE: Schichtl), referencing D.02-03-055 and D.06-07-030. *See also id.* at 21:14-16 (emphasis added) ("[T]he indifference amount is calculated to represent the *total portfolio*, rather than for different types of generation resources.").

[118] RT at 136:15-16 (SCE: Schichtl). *See also* Exh. 300 at 19:22-23 (SCE: Schichtl) ("Statutory Competition Transition Charge (CTC) revenue is subtracted from the indifference amount to produce the Power Charge Indifference Adjustment (PCIA).")

[119] RT at 136:20-21 (SCE: Schichtl).

[120] *See* Exh. 800 at 8 (CLECA/CMTA: Dr. Barkovich) ("[The Commission] decided that if the indifference amount were calculated to be less than zero, the PCIA would be set to the opposite of the CTC…."). *See also* Exh. 801 at 6 (CLECA/CMTA: Dr. Barkovich)("[I]f the indifference amount is less than the CTC, there can be a negative PCIA.").

[121] Exh. 400 at 1-16:21-24 (PG&E: Barry).

[122] *See* Exh. 400 at 1-16:27 (PG&E: Barry).

be used as a means to indirectly offset the Ongoing CTC," since this approach "contravenes Pub. Util. Code Section 367(a) and Decision 05-12-045."[123] To remedy this perceived problem, PG&E proposes that, where the Indifference Amount is less than or equal to CTC, the PCIA should be set to zero, instead of being negative and allowed to offset the CTC.[124]

The Commission should reject PG&E's proposal to eliminate the offsetting effect of the negative PCIA. At seemingly every juncture in the storied history of the PCIA, PG&E has tried to eliminate the mitigating effect of negative CRS elements, whether it is the PCIA or other charges. In response, the Commission has repeatedly rejected PG&E's efforts, principally because PG&E's proposals undermine and violate the overarching rule governing non-bypassable charges – the bundled customer indifference principle. On similar legal and policy grounds, the Commission should, yet-again, reject PG&E's recycled proposal in this proceeding.

b. PG&E's Claim Of Prior Commission Neglect Is Inaccurate

As mentioned above, PG&E states that "[o]ne consideration that should have been more thoroughly examined [by the Commission] is the effect the negative PCIA has on bundled customer indifference."[125] Moreover, PG&E also states that there is a "*logical flaw* in the current indifference calculation," intimating that the Commission has either neglected this issue or made an unintentional mistake.[126] Such assertions are inaccurate; the Commission has *exhaustively* addressed this issue, and has been very purposeful in its design of the indifference calculation. The fact that the Commission has reached different conclusions than PG&E is no reason to suggest, as PG&E does, that the Commission has not thoroughly examined the effect the

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[123] Exh. 400 at 1-17:2-5 (PG&E: Barry). *See also* RT at 323:24-26 (PG&E: Barry) ("Decision 06-07-030 does allow the PCIA to go negative [but] I think it's contrary to [statutory] intent.") and RT at 322:26-28 (PG&E: Barry).

[124] *See* Exh. 400 at 1-18:5-6 (PG&E: Barry).

[125] Exh. 400 at 1-16:27-29 (PG&E: Barry).

[126] Exh. 400 at 1-18:1-2 (PG&E: Barry) (emphasis added).

negative PCIA has on bundled customer indifference, or that the Commission has been illogical and careless.

PG&E has raised similar issues on two previous occasions, and on both occasions the Commission has concluded that the principle of "bundled customer indifference will only be maintained if all resources are included in the portfolio used to calculate the related charges, whether it is the ongoing CTC, DWR power charges and D.04-12-048 charges or just the ongoing CTC and D.04-12-048 charges."[127] Contrary to PG&E's assertion, in the various times that the Commission has addressed the use of the negative PCIA, the central focus of the Commission's inquiry has been on *bundled customer indifference*.

The use of negative PCIA was first addressed by the Commission in D.06-07-030, in which the Commission expressly held that "[t]he PCIA component of DA CRS may be a negative number in those instances in which ongoing competition transition charge (CTC) is larger than the indifference charge, *so that overall indifference is maintained*."[128] The Commission addressed a similar issue in D.07-05-005, which was issued in response to a petition for modification filed by PG&E. PG&E argued that negative CRS amounts should not be carried-forward to be used to offset positive CRS amounts. In D.07-05-005, the Commission rejected PG&E's proposed modification, expressly stating that "PG&E's proposed modification would not result in bundled customer indifference."[129] The Commission affirmed that "in order to maintain indifference, both positive and negative indifference effects must still be tracked, with the negative amounts offsetting positive amounts."[130]

[127] D.08-09-012 at 51.

[128] D.06-07-030; Ordering Paragraph 7 (emphasis added).

[129] D.07-05-005 at 19.

[130] D.07-05-005 at 19.

PG&E availed itself of yet another opportunity to address a similar issue in R.06-02-013 – the proceeding that examined how the indifference amount should be calculated with the inclusion of so-called "new world" generation resources. In that proceeding, as it likewise proposes in this proceeding, PG&E advanced a proposal that, if approved, would have resulted in a negative indifference element *not* being used to offset the CTC. The Commission referred to PG&E's proposal as the "separate charge approach," contrasting PG&E's proposal with the "total portfolio approach." Under PG&E's separate charge approach, PG&E proposed to calculate CRS elements separately, not allowing the netting and carrying forward of any negative amount associated with new world generation resources. In rejecting PG&E's proposal, the Commission first affirmed the ongoing relevance of D.07-05-005 with respect to the principle of bundled customer indifference, stating that "[w]hile the Commission's reasoning in [D.07-05-005] applied to the existing DA/DL CRS calculations, the basic principles directly relate to handling of negative charges in this proceeding…."[131] As it had previously concluded in D.07-05-005, the Commission likewise concluded in D.08-09-012 that "[i]t is similarly necessary that negative indifference amounts be carried over for use in subsequent years to maintain bundled customer indifference. The total portfolio approach is consistent with this principle. PG&E's separate approach is not."[132] The Commission expressly stated, as it had previously, that the total portfolio approach allows CTC to be offset by other negative CRS elements.[133]

[131] D.08-09-012 at 48.

[132] D.08-09-012 at 48.

[133] D.08-09-012 at 58 ("To summarize, we adopt the use of a CRS calculation using a total portfolio approach that accounts for the ongoing CTC, DWR and D.04-12-048 charges. This includes netting the individually calculated annual charges and carrying over any negative total charge to offset positive charges in subsequent years.").

c. PG&E Confounds the Bundled Customer Indifference Principle

As described above, past Commission decisions have been resolutely focused on achieving bundled customer indifference. To accomplish this, the Commission has employed the total portfolio approach, which uses all resources to calculate the various NBCs.[134] The Commission's approach is holistic; PG&E's approach is not. Rather, PG&E unduly isolates and protects one element of the Indifference Amount (the CTC), and in doing so PG&E confounds the bundled customer indifference principle.

PG&E's preoccupation on the CTC is seen most vividly in PG&E's analysis of the indifference principle. First, PG&E is unable to admit that the CTC is even remotely relevant in the determination of bundled customer indifference.[135] Second, instead of focusing on how much departing customers contribute in *total*, and the effect of this contribution on bundled customers' *total* cost, PG&E focuses exclusively on how much each customer group contributes *to the CTC*, and bases its conclusion regarding indifference on that standard.[136] Contrary to PG&E's beliefs, bundled customer indifference is clearly determined with reference to *total portfolio* costs, not isolated costs related to just the CTC.[137]

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[134] *See, e.g.,* RT at 1134:6-7 (SCE:Schichtl) ("The total portfolio method is intended to include all resources."). *See also* Exh. 300 at 21 (SCE: Schichtl)("SCE proposes to retain the total portfolio method. That is, the indifference amount is calculated to represent the total portfolio, rather than for different types of generation resources. In this way, the 'below market' costs of certain generation resources offset the 'above market' costs of higher cost resources, such that the relevant issue is the average cost of the portfolio relative to its market value.").

[135] *See* RT at 314:17-22; 315:1-2 (PG&E: Barry) ("Q. Is bundled customer indifference determined only with respect to ongoing CTC? A. The bundled customer indifference has no bearing on the ongoing CTC determination. . . . Again, the indifference concept doesn't apply to ongoing CTC."). *See also* RT at 317:2-14 (PG&E: Barry) and RT at 324:19-21 (PG&E: Barry).

[136] *See, e.g.,* Exh. 400 at 1-16:9-11 (PG&E: Barry) ("Exempt customers are clearly not indifferent as they are treated unequally with respect to how much they contribute to the Ongoing CTC recovery versus similarly situated non-exempt customers.") PG&E also errs in focusing on "exempt customers" instead of "bundled customers" in determining indifference.

[137] *See, e.g.,* note ***[19]***, above, referring to D.08-09-012 at 58 ("To summarize, we adopt the use of a CRS calculation using a total portfolio approach that accounts for the ongoing CTC, DWR and D.04-12-048 charges.").

This distorted reasoning is also shown in PG&E's singular focus on "increased ERRA costs" instead of *total* costs.[138] Again, bundled customer indifference is determined with reference to total portfolio costs, not isolated costs related to just the ERRA costs. While it may be true in the example PG&E posits[139] that "bundled customer costs in ERRA would increase" this is a red herring and irrelevant, *in isolation*, to the question of bundled customer indifference. The fact that there is a negative PCIA means that any increase in bundled customer costs in ERRA is less than the *corresponding* benefit bundled customers receive by having the utility serve bundled customers' load with lower-cost utility resources instead of purchasing from the higher-cost market to meet this need.[140] As demonstrated by the Joint Parties,[141] PG&E's proposal violates the bundled customer indifference principle because it would only recognize the cost to bundled customers from using more of the above-market CTC resources, and would not recognize the corresponding or offsetting *benefit* that accrues to bundled customers from also using more of the below-market utility resources.

Finally, PG&E's skewed reasoning is also seen in the undue significance that PG&E attaches to pre-D.06-07-030 decisions, in particular the so-called CTC decision (D.05-12-045). For example, PG&E states that "The PCIA should not be used as a means to indirectly offset the Ongoing CTC, which is effectively the net result when the PCIA is less than zero. This

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[138] *See, e.g.,* Exh. 400 at 1-17:23-27 (PG&E:Barry) ("[A] negative PCIA effectively results in increased ERRA costs, which bundled customers are required to pay. Thus, while non-exempt customers would be paying a net result that is zero or at least lower than the Ongoing CTC, *bundled customer costs in ERRA* would increase.").

[139] (Exh. 400 at 1-17:16-27 (PG&E: Barry).

[140] *See, e.g.,* Exh.300 at 19:17-19 (SCE: Schichtl) ("A negative value for the indifference amount essentially means that bundled service customers benefit from the departure of customers, because energy and capacity produced by the portfolio is more valuable in the market than if sold to departing customers."). *See also* D.08-09-012 at 41 ("If the total portfolio costs are lower than market costs resulting in a negative indifference amount, the customers' departure is economic.").

[141] *See* Exh. 101 at 20:9-21 (Joint Parties: Meal, Dalessi, Fulmer).

contravenes Pub. Util. Code Section 367(a) and Decision 05-12-045."[142] Additionally, PG&E also states that "[t]wice [in D.02-11-022 and D.5-12-045], the Commission has reaffirmed that the total portfolio indifference calculation in no way implicates or otherwise impacts the Ongoing CTC."[143] The problem with PG&E's reasoning is that it is stuck in time; specifically, it is stuck in time prior to D.06-07-030. As even PG&E reluctantly admits, D.06-07-030 did, in fact, "implicate" and "impact" the CTC.[144] Subsequent Commission decisions have affirmed this point and rendered baseless PG&E's reliance on D.05-12-045.

d. PG&E's Proposal Violates the Bundled Customer Indifference Principle

PG&E claims that departing customers' "ability to have low cost generation to offset some portion of their Ongoing CTC contribution, directly or indirectly through a negative rate, violates the guiding principles that bundled customers remain indifferent to departures."[145] The opposite is true. An artificial limitation on the offsetting effect of low-cost utility retained generation, which would be the result under PG&E's proposal, violates the bundled customer indifference principle.

As the Commission has repeatedly acknowledged, the principle of bundled customer indifference can only be maintained if *all resources* are netted against each other.[146] "All resources" must include "low cost generation" in order to be consistent with the Commission's

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[142] Exh. 400 at 1-17:2-5 (PG&E: Barry).

[143] Exh. 401 at 5:32 – 6:1-2 (PG&E: Barry).

[144] *See* Exh. 400 at 1-16:21-24 (PG&E: Barry) ("Decision 06-07-030, which modified the Indifference calculation, also modified the constraints on the Indifference Charge (*e.g.*, PCIA) such that it could be negative up to the level of the Ongoing CTC.").

[145] Exh. 400 at 1-16:5-8 (PG&E: Barry).

[146] *See, e.g.,* D.08-09-012 at 99; FOF 26 (emphasis added) ("Bundled customer indifference will only be maintained if *all resources* are included in the portfolio used to calculate the related charges, whether it is the CTC, DWR and D.04-12-048 charges or just the CTC and D.04-12-048 charges.").

total portfolio approach.[147] By not allowing all resources to be netted against each other, and effectively creating separate charges, as PG&E proposes, bundled customers are not indifferent, but are better off, which is impermissible.[148] This is so because in these situations bundled customers would effectively retain the *benefit* of *below*-market CTC resources (such as utility retained resources) while at the same time effectively receiving a payment from departing customers for the *cost* of *above*-market CTC resources (such as certain Qualifying Facility ("QF") resources). As recognized by SCE, PG&E's separate-resources approach is inconsistent with the total portfolio approach.[149] Moreover, the Commission has rightly concluded that PG&E's separate-resources approach, which inherently only recognizes the costs but not the benefits of departure, violates the bundled customer indifference principle.[150]

Other parties share the Joint Parties' view regarding PG&E's proposal and its effect on the bundled customer indifference principle. CLECA/CMTA state that PG&E's proposal would be "inequitable to all parties and would undermine the indifference concept."[151] SCE is also on the record as not supporting PG&E's negative PCIA proposal.[152] SCE's witness freely

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[147] *See, e.g.* D.08-09-012 at 99; FOF 27 (emphasis added) ("The use of the total portfolio *and the inclusion of the pre-restructuring resources in that portfolio* is the appropriate approach to use for the duration of D.04-12-048 cost recovery.").

[148] *See, e.g.,* D.08-09-012 at 45 ("[B]undled customer indifference means that bundled customers should be no worse off nor should they be any better off due to departing loads.").

[149] *See* Exh. 300 at 21:14-18 (SCE: Schichtl) ("[T]he indifference amount is calculated to represent the total portfolio, rather than for different types of generation resources. In this way, the 'below market' costs of certain generation resources offset the 'above market' costs of higher cost resources, such that the relevant issue is the average cost of the portfolio relative to its market value.")

[150] *See* D.07-05-005 at 25 ("If only positive amounts were recognized while negative amounts were ignored, the resulting calculation would be inconsistent and would not achieve indifference.").

[151] Exh. 801 at 8 (CLECA/CMTA: Dr. Barkovich) at 8. *See also id.* ("[T]he PG&E proposal to require all customers to pay the CTC regardless of the level of the indifference amount is unfair and inappropriate. . . . [PG&E's proposal] is not consistent with D.06-07-030.").

[152] *See* RT at 135:19-25 (SCE: Schichtl).

acknowledged that both elements of the Indifference Amount are needed in order to achieve bundled customer indifference:

> Q. So is it fair to say that [to achieve bundled customer indifference] you need to allow both the PCIA and the CTC to be determined as currently determined?
>
> A. Do you mean the determination of PCIA by subtracting CTC with the indifference amount?
>
> Q. Correct.
>
> A. Yes.[153]

E. Other proposals for changes to ongoing CTC

Not addressed.

F. Implementation of proposed changes

The Joint Parties recommend that the changes discussed above be implemented as soon as possible. Correcting significant distortions in the calculation of NBCs is time critical. Last year, MEA became the first CCA to commence serving customers, and CCSF intends to commence soon. Commencing a CCA program at a time when inaccurate NBCs significantly skew the competitive landscape severely disadvantages CCA programs and could greatly reduce the benefit of the opt-out approach included by the legislature in AB 117.

Similarly, after years of a moratorium on new direct access, D.10.03-022 authorized and implemented a plan for increased limits in the allowed level of DA transactions within the service territories of California's three major IOUs. Subject to a cap, the decision authorized a four-year phase-in period, commencing in 2010. This reopening of DA was met with exceptionally high customer interest, with all available capacity subscribed within approximately one minute of the times established for customers to file notices of intent to return to direct

[153] RT at 138:4-11 (SCE: Schichtl).

access. The level of the NBCs is a critical component of customers' decisions with respect to direct access, and thus, timely review and correction of the methodology for the calculation of NBCs is increasingly critical.

V. Conclusion

In conclusion, the record compiled in this proceeding demonstrates convincingly that the methodology used to calculate the PCIA and ongoing CTC is flawed and defective. The primary defect is that the Market Price Benchmark used in the PCIA and CTC methodologies is too low and does not accurately reflect the value of key attributes of the IOUs' supply portfolios. In addition, the Total Portfolio Costs is calculated inconsistently among the IOUs, and in the case of some IOUs includes costs that would be avoided by the departure of load. As a result of these flaws bundled customer indifference to the departure of load is not achieved; rather, bundled customers benefit unfairly at the expense of departed customers. The evidence supports the proposals to correct these flaws put forward by the Joint Parties, and these proposals should be adopted.

Respectfully submitted,

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May 6, 2011

CERTIFICATE OF SERVICE

I, Arlene G. Hall, declare that:

I am employed in the City and County of San Francisco, State of California. I am over the age of eighteen years and not a party to the within action. My business address is City Attorney's Office, City Hall, Room 234, 1 Dr. Carlton B. Goodlett Place, San Francisco, CA 94102; telephone (415) 554-4680.

On May 6, 2011, I served:

OPENING BRIEF OF CALIFORNIA STATE UNIVERSITY, MARIN ENERGY AUTHORITY, CALIFORNIA MUNICIPAL UTILITIES ASSOCIATION, CITY AND COUNTY OF SAN FRANCISCO, SAN JOAQUIN VALLEY POWER AUTHORITY, ALLIANCE FOR RETAIL ENERGY MARKETS, DIRECT ACCESS CUSTOMER COALITION, BLUESTAR ENERGY, PILOT POWER GROUP, INC. AND ENERGY USERS FORUM

by electronic mail on all parties on the service list in **Proceeding No. R.07-05-025**.

The following addressee(s) without an email address were served:

☒ **BY UNITED STATES MAIL**: Following ordinary business practices, I sealed true and correct copies of the above documents in addressed envelope(s) and placed them at my workplace for collection and mailing with the United States Postal Service. I am readily familiar with the practices of the San Francisco City Attorney's Office for collecting and processing mail. In the ordinary course of business, the sealed envelope(s) that I placed for collection would be deposited, postage prepaid, with the United States Postal Service that same day.

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I declare under penalty of perjury that the foregoing is true and correct and that this declaration was executed on May 6, 2011, at San Francisco, California.

/S/
____
Arlene G. Hall