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PACIFIC GAS AND ELECTRIC COMPANY

DIRECT ACCESS REOPENING PHASE III

PREPARED TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
DIRECT ACCESS REOPENING PHASE III

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INTRODUCTION AND POWER CHARGE INDIFFERENCE AMOUNT MODIFICATION

A. Introduction

Pursuant to the *Assigned Commissioner's Ruling Adopting Amended Scoping Memo and Schedule* issued in this proceeding on November 22, 2010 (November 22 Ruling), technical workshops on the Phase III issues were held on December 7, 14-15, 2010 and January 4, 2011.[1] The workshops were intended to provide parties a forum to discuss and seek consensus regarding the methodology for calculating the Power Charge Indifference Amount (PCIA) and the other related, yet unresolved, Phase III issues, including switching rules, the Transitional Bundled Service (TBS) rate, and Electric Service Providers' (ESP) financial security (or bond) requirements. The first two workshops focused on the PCIA calculation and issues related to the PCIA and the third workshop addressed the other unresolved Phase III issues. Numerous parties were represented at the workshops.[2]

At the workshops, parties presented various proposals concerning modifications to the methodology for determining the Indifference Amount and the resulting PCIA. Parties largely focused on changes to the Market Price Benchmark (MPB), but also proposed changes to other aspects of the Indifference calculation. Ultimately, the parties participating in the workshops

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[1] The original November 22 Ruling called for three workshops and a fourth workshop was added (January 4, 2011) at the request of parties.

[2] Parties participating at the workshop included Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), San Diego Gas and Electric, the Division of Ratepayer Advocates, The Utility Reform Network, ESPs (Alliance for Retail Energy Markets, Direct Access Customer Coalition, Bluestar Energy, Constellation Energy, among others), Community Choice Aggregators (CCA) (Marin Energy Authority, San Joaquin Valley Power Authority), prospective CCAs (City and County of San Francisco), large Direct Access (DA) customers (Walmart, California State University), large customer advocacy groups (California Large Energy Consumers Association, California Manufacturers and Technology Association (CMTA) and Energy Users Forum), and other interests (California Department of Water Resources (CDWR), California Municipal Utilities Association, Energy Producers and Users Coalition, among others).

were unable to reach a consensus on the appropriate MPB and PCIA modifications and a resolution of the other Phase III issues. In this chapter, PG&E proposes modifications to the MPB that appropriately reflect the market value of renewables and refine the shape of the generation profile. With respect to the Indifference calculation, PG&E proposes to fix a logical flaw in the determination of the PCIA, keeping in mind the guiding principles of bundled customer indifference and the obligation of each customer to pay its fair share of costs. These guiding principles are the foundation of California Public Utilities Commission (CPUC or Commission) decisions regarding Non-Bypassable Charges (NBC) to recover stranded costs.[3] In Chapters 2-4, PG&E addresses other Phase III issues, as described in more detail below.

B. Testimony Organization

PG&E's testimony is organized as follows:

- Chapter 1: This chapter focuses on issues related to the MPB and Indifference and PCIA calculations, including a summary of parties' proposals presented over the course of the four-day workshop. PG&E highlights areas where parties appeared to reach common ground, at least conceptually. Chapter 1 also includes PG&E's proposal for modifying the MPB, the Indifference calculation, and the PCIA.
- Chapter 2: This chapter presents PG&E's proposal with respect to the TBS rate.
- Chapter 3: This chapter discusses PG&E's proposal with respect to ESP switching rules.
- Chapter 4: This chapter describes counterparty credit risk components, product risk, and standard industry practice for managing counterparty risk. In addition, PG&E discusses commercially available security products and PG&E's proposal for establishing financial security requirements for ESPs.

[3] See Decision 08-09-012 at pp. 10-11 (describing the Commission's guiding for NBCs).

C. Current Methodology to Calculate the Indifference Amount, PCIA, Ongoing CTC, and MPB

1. Guiding Principles

The indifference standard was originally discussed in the Direct Access Suspension proceeding, Rulemaking 02-01-011, when the Commission was considering how to equitably allocate costs associated the CDWR contracts between bundled customers and customers that returned to DA service between February 2001 and September 2001.[4] The Commission wanted to ensure that bundled customers remained indifferent to stranded costs resulting from customers returning to DA service before September 2001. Establishing a reasonable approximation of the indifference amount or cost shifting that would result from the departing load ensured that the CDWR contract costs would be equitably allocated between bundled and DA customers.

Additionally, since the passage of Assembly Bill (AB) 1X and the opening of DA Suspension Rulemaking 02-01-011, the Commission was mandated by law to ensure that customers pay their fair share of costs incurred on their behalf. The Legislature passed AB 117, which was signed into law on September 24, 2002.[5] Although AB 117 is primarily about CCA programs, the Legislature took the opportunity to amend Public Utilities Code (Pub. Util. Code) Section 366 to add subsection (d) in order to clarify

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[4] As directed by the Legislature in AB1X, the Commission suspended the right of retail customers to chose direct access service – see Decision 01-09-060 as modified by Decision 01-10-036, which set the effective date for DA suspension at September 20, 2001 (Ordering Paragraph (OP) 4) and determined that "Avoiding cost-shifting and establishing a stable customer base justify why suspension of direct access should not be delayed." (Finding of Fact (FOF) 6).

[5] Stats 2002, ch. 838.

its intent concerning the cost responsibility of each retail end-use customers who was a customer on or after February 1, 2001.[6]

In Decision 02-11-022, the Commission adopted a methodology that considered the Investor-Owned Utility's (IOU) total portfolio of generation resources and evaluated the rate impact on bundled customers before and after customer departures.[7] The methodology adopted in Decision 02-11-022 remained in place until mid-2006 when Decision 06-07-030 adopted a revised calculation methodology, effective January 1, 2006, that shifted the focus of the indifference calculation from one that evaluated changes in the average cost of bundled customer's costs to one that compared the average portfolio cost to the value of the portfolio in the market and allowed the indifference charge paid by departing customers (*e.g.*, the PCIA), to be negative.[8] Allowing customers to be billed a negative rate, which is akin to a credit amount, was a significant and a material departure from the original conceptual framework that departing customers should not benefit if they decide to depart at the expense of the

[6] Pub. Util. Code Section 366.1(d): "It is the intent of the Legislature that each retail end-use customer that has purchased power from an electrical corporation on or after February 1, 2001, should bear a fair share of the [DWR's] electricity purchase costs, as well as electricity purchase contract obligations incurred. . . that are recoverable from electrical corporation customers in commission-approved rates. It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers." (Pub. Util. Code, § 366, subd. (d)(1).)

[7] D.02-11-022, FOF 1 and 2, "The change in DA load levels between July 1 and September 20, 2001, inclusively, results in an increase in the average cost of power for remaining bundled customer because total uneconomic costs are spread over a smaller sales base" and "D.02-03-055 determined that as a condition of retaining the DA suspension date of September 1, 2001, a surcharge must be imposed on DA customers sufficient to make bundled customers economically indifferent between a DA suspension date of July 1 versus September 21, 2001."

[8] D.06-07-030, OP 7, "The ongoing Competition Transition Charge (CTC) figure adopted on an annual basis in PG&E's Energy Resource Recovery Account (ERRA) proceeding will be used in conjunction with the CRS indifference charge calculation such that the DWR power charge component of CRS for DA customers not exempt from that charge will be the residual of the indifference charge less the ongoing CTC. The PCIA component of DA CRS may be a negative number in those instances in which ongoing CTC is larger than the indifference charge, so that overall indifference is maintained."

remaining bundled customers.[9] More recently, the Commission affirmed the indifference principle as a guiding principle for addressing stranded cost recovery and NBC issues. In addition, the Commission reiterated Pub. Util. Code Section 366.1(d) that all customers, departing and bundled, pay their "fair share" of costs incurred on their behalf. In Decision 08-09-012, the Commission explained that:

> The notion that each customer pay its fair share of the costs the IOU incurred on behalf of this customer or the load associated with this customer is part of these guiding principles. Therefore, the rule is that when costs are incurred on its behalf, that customer must pay its fair share of the costs. A corollary rule is that if no costs are incurred on its behalf, then the customer's fair share can be determined to be zero.[10]

2. Indifference Calculation Overview

The current total portfolio calculation methodology adopted in Decision 06-07-030 replaced the methodology approved in Decision 02-11-022. The Decision 06-07-030 methodology involves a number of defined and detailed calculations but generally can be characterized as an above-market calculation where the total cost of PG&E's portfolio is compared to the market value and the difference represents stranded or above-market costs, to be recovered from all bundled and non-exempt customers. The stranded cost is the amount that needs to be collected from all customers so that bundled customers remain indifferent. Thus, the stranded or above-market costs have also been referred to as the Indifference Amount. The Decision 06-07-030 methodology defined the Indifference Amount according to the following formula:

Indifference Amount = Ongoing CTC + PCIA

Below, PG&E provides a brief overview of the components in the above formula.

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[9] D.02-11-022, fn. 24: "The total portfolio approach we adopt, involving the netting of high-cost URG against low-cost sources of power, is intended only for the express purpose of computing bundled ratepayer indifference during the period that DWR-related costs are being paid for through a DA CRS. Nothing in this order should be construed as creating any claim on low-cost URG by DA customers beyond the period covered by the DA CRS into perpetuity."

[10] D.08-09-012 at p. 10 (footnotes omitted).

a. Indifference Amount and the PCIA

The Indifference Amount represents the difference between PG&E's total portfolio costs and the value of the portfolio using the MPB. PG&E's total portfolio includes a forecast of costs and generation for the following year for: (1) PG&E owned generation resources; (2) contracted generation resources greater than a year in duration; (3) CDWR contracts; and (4) all associated fuel costs and California Independent System Operator (CAISO) costs that support the generation. To determine the market value of PG&E's total portfolio, PG&E multiplies the MWh for the total portfolio described above by the MPB.[11]

The Indifference Amount represents the above-market costs of the total portfolio and is the difference between the total portfolio costs and the market value of the portfolio.

Indifference Amount = Total Portfolio Costs – Total Portfolio Value

If the results are negative (*i.e.*, PG&E's total portfolio is below market), the Indifference Amount is set to zero, and the negative result is tracked in a memorandum account and available to offset future positive indifference results.

If Total Portfolio Costs – Total Portfolio Value < 0, then 0 and
Total Portfolio Costs – Total Portfolio Is Tracked in NIAMA

If the results are positive, then the PCIA is determined by subtracting the Ongoing CTC from the Indifference Amount and the result is the PCIA, as illustrated below:

If Total Portfolio Costs – Total Portfolio Value >= 0,
Then Indifference Amount – Ongoing CTC = PCIA

The PCIA is to recover stranded costs associated with CDWR contracts and PG&E's post-2003 generation commitments.

b. Ongoing CTC

The purpose of Ongoing CTC is to recover uneconomic costs resulting from California's electric industry restructuring from all customers responsible for those costs. Ongoing CTC is collected from

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[11] The MPB is described in more detail below in Section C.3.

all existing and future consumers as of December 20, 1995,[12] for all power purchase contract costs included in CPUC rates as of that date. PG&E's pre-1996 contracts are with Qualifying Facilities (QF), Irrigation Districts and Water Agencies agreements, Metropolitan Water Agency, and City and County of San Francisco. Because energy payments to QFs are in proportion to natural gas prices, PG&E executes financial hedges against these costs. The costs or benefits of these hedges are considered a part of QF purchase costs and thus are included in the Ongoing CTC calculation.

The above-market cost for Ongoing CTC-eligible contracts is the difference between their total cost and the market value if the same volume of electricity megawatt-hour (MWh) were purchased at the MPB. Costs associated with CPUC-approved QF contract restructurings are added directly to the above-market cost to produce the total Ongoing CTC cost.

In PG&E's 2006 ERRA Forecast decision, Decision 05-12-045, the Commission addressed the calculation method for determining the Ongoing CTC and in OP 6, affirmatively determined that:

> Ongoing CTC shall be calculated in accordance with the statutory method described in the body of this Order. If the above-market component of ongoing CTC is negative, this negative amount may offset positive above-market costs included in ongoing CTC to the extent set forth in the body of this Order.

> The Commission made the above determination in light of parties' arguments in PG&E 2006 ERRA Forecast Proceeding that the Ongoing CTC should be based on a total portfolio approach that nets low cost URG generation against higher cost resources and calculations that produce a negative result should allow for offset of other components of the Cost Responsibility Surcharge (CRS).

In addition to affirming the statutory calculation for the Ongoing CTC, OP 6 also confirmed that any negative result using the statutory calculation would used to offset only future positive Ongoing CTC amounts.[13] That is, to the degree there are any negative results using the statutory method to calculate the Ongoing CTC, it would only

[12] Public Utilities Code § 369.

[13] See also D.05-12-045, COL 6 and pp. 20-22.

be eligible to offset future Ongoing CTC. It cannot be used to offset other elements of departing customers' CRS obligations.

3. Commission-Adopted Market Price Benchmark

Decision 06-12-018 (pp. 11-12) directed the IOUs to use a Commission-adopted Market Price Benchmark or "MPB" for calculating the Indifference Amount, Ongoing CTC, and the PCIA. The benchmark is calculated annually by the Energy Division (ED) according to the procedure adopted in Decision 06-07-030, Appendix 1, as modified by Decision 07-01-030 (OP 2). The benchmark is calculated by ED as follows:

- Collect daily forward price quotes from October 1 through October 31 for 12 months of on-peak (6 days x 16 hours/day) and off-peak (6 days x 8 hours/day; 1 day x 24 hours/day) power delivered at North of Path 15 (NP-15) in 2009, as published in *Megawatt Daily*.[14]
- Average the daily quotes to get an annual on-peak forward price and an annual off-peak forward price.
- Determine a weighted average 24 x 7 forward power cost by multiplying the average on-peak price times the fraction of annual on-peak hours, and the average off-peak prices times the fraction of off-peak hours, and then adding the two.
- Add a resource adequacy/capacity cost to the 24 x 7 forward price. This adder for PG&E is $4/megawatt-hour (MWh).[15]
- Add a line loss factor.[16]

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[14] As of November 2007, *Megawatt Daily* no longer published forward market quotes for on-peak and off-peak energy. However, the successor publication by the same publisher, Platts, is publishing the required data. Thus, post 2007, Energy Division relied on *Platts-ICE Forward Curve – Electricity for NP 15* as the successor publication to *Megawatt Daily*.

[15] The Commission recognized in Decision 07-01-030 that until a functioning and transparent capacity market or a suitable public index becomes available, the resource adequacy/ capacity adder will be formulated by consensus among the interested parties.

[16] The contract costs used to calculate CTC are based on delivery at load centers whereas the forward price quotes are based on delivery at NP-15. A line loss factor to account for delivery losses from NP-15 to load centers was applied to the sum of the forward price cost and the resource adequacy/capacity cost to arrive at the final benchmark value. Decision 07-01-030 set the line loss factor at 6.0 percent for PG&E.

D. Summary of Workshop Proposals

The Joint Parties in this proceeding filed a motion on September 23, 2010 seeking an expedited phase to consider modifications to the methodology used to determine NBCs, and specifically the calculation of the PCIA.[17] In particular, the Joint Parties asserted that the Commission-approved MPB needed to be adjusted in part to reflect the value of Renewable Portfolio Standard (RPS)-eligible resources. The November 22 Ruling granted this motion and added PCIA issues to Phase III of this proceeding. The November 22 Ruling also directed the parties to participate in a series of workshops to address technical issues regarding the MPB, PCIA and other remaining unresolved Phase III issues. Below is a summary of the proposals made at the technical workshops.[18]

1. December 7 Workshop

During the December 7, 2010 workshop, the participating parties made four presentations that included proposals to modify the MPB, Indifference Amount, Ongoing CTC, and PCIA. These presentations are summarized below:

1. **PG&E** – PG&E proposed modifying the Indifference calculation so that the PCIA cannot be less than zero. Under the current methodology, if the Indifference Amount is less than zero, it is set to zero and the negative PCIA result indirectly offsets the Ongoing CTC. PG&E's proposal would eliminate the negative PCIA rate by establishing a constraint that when the Indifference Amount is less than the Ongoing CTC, the PCIA would be set to zero. The negative results (*i.e.*, Indifference – Ongoing CTC) would instead be banked in the Negative Indifference Amount Memo Account (NIAMA) and used to offset future positive PCIA amounts, which is more consistent with the constraints the Commission adopted in Decision 05-12-045 for the Ongoing CTC and better preserves bundled customer indifference.

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[17] November 22 Ruling, at p. 2.

[18] This section is only intended to provide a brief summary the parties' proposals for background to PG&E's testimony. The complete presentations and proposals are attached to the *Workshop Report of the Joint Parties*, filed on January 14, 2011 in this proceeding.

2. **Joint Parties** – presented by Mark Fulmer of MRW & Associates, on behalf of the Joint Parties: The Joint Parties asserted that the MPB does not reflect the value of renewable resources and, as a result, costs are shifted to departing load. To address this, the Joint Parties' proposed four alternative solutions: (1) remove RPS resources from the Indifference Amount calculation; (2) adjust the MPB; (3) segregate RPS resources and calculate separate results for the PCIA; or (4) allocate a share of the renewable attributes associated with RPS-eligible contracts to CCAs and ESPs

3. **Joint Parties** – presented by CleanPowerSF, San Francisco Public Utilities Commission, on behalf of the Joint Parties: The Joint Parties asserted that several attributes and IOU costs are included in total portfolio calculations that are assigned to departing load customers but neither the value of the attributes nor the IOU costs are reflected in the MPB. The Joint Parties proposed that this discrepancy be corrected.

4. **Joint Parties** – presented by John Dalessi, representing Marin Energy Authority: The Joint Parties maintained that the MPB methodology does not include the value of CAISO services even though the costs associated with CAISO services are included in the total portfolio costs. CAISO charges are avoidable and there are many examples of load-based CAISO charges. The Joint Parties suggested that MPB should be adjusted for CAISO services. In addition, the MPB does not include the value of resources needed to serve the shaped load of customers even though costs associated with these resources are included in total portfolio costs. The Joint Parties' proposed solution would be to replace the current baseload MPB with a load-weighted MPB.

2. December 14 Workshop

At the December 14, 2010 workshop, PG&E and SCE presented a counterproposal addressing all of the issues raised by counterparties with respect to the Indifference Amount, Ongoing CTC, and PCIA calculations. The PG&E/SCE proposal is summarized below:

- **Market Price Benchmark**
  – Update the generation capacity adder included in the MPB.

– Adjust the MPB to reflect the value of certain renewable resources in an IOU's portfolio.

– Reflect a shaped energy price in the MPB so that the price is weighted based on peak and off-peak generation reflected in the IOU's total portfolio.

ffi **<u>Total Portfolio Cost Calculation</u>**

– Exclude forecasted CAISO costs associated with load (variable)

– Exclude short-term (*i.e.*, less than one year) transactions[19]

ffi **<u>Switching Rules, TBS and Security Requirements</u>**

– Continuation of DA switching rules requiring 6-month notice to depart or return to bundled portfolio service (BPS) and an 18-month stay on BPS when a customer returns.

– Security requirements for involuntary returns calculated using the method recommended in the CCA Bond/Re-Entry Fee Settlement proposed in Rulemaking 03-10-003.

– Update of the TBS rate consistent with MPB changes for generation capacity and RPS value.

After PG&E and SCE presented their counterproposal, there was significant discussion regarding the specifics of the proposal and the parties subsequently developed an IOU "to do" list that requested additional information to facilitate parties' evaluation of the counterproposal. The requested information included: (1) 2009 Federal Energy Regulatory Commission Form 1 Data and average cost of renewables in the IOUs' portfolios; (2) sensitivity analysis for the capacity proposal, removal of pre-2003 RPS renewables, generation-weighted profile adjustment, and removal of the CAISO costs; (3) continuous DA prevalence; (4) TBS scalars linked to the MPB; and (5) an update to a 2007 data request evaluating the impact of renewables on the 2011 PCIA.

[19] This element of the SCE-PG&E proposal only applies to SCE because PG&E already excludes short-term transactions from its total portfolio cost calculations.

3. December 15 Workshop

The December 15, 2010 workshop focused primarily on Phase III issues other than the MPB and PCIA. The parties agreed to an additional workshop in January 2011.

4. January 4 Workshop

At the January 4, 2011 workshop, the Joint Parties presented a counterproposal to the PG&E and SCE proposal. The Joint Parties indicated that they were willing to agree to some of the PCIA adjustments proposed by PG&E and SCE. However, there was still fundamental disagreement on at least one issue related to adjustments to the PCIA, as well as issues related to switching rules, security requirements, and the TBS rate.

E. PG&E's Proposed Modifications to the Market Price Benchmark, Indifference Calculation, and PCIA

1. Market Price Benchmark

The goal of the modifications that PG&E is proposing to the Indifference Amount calculation, PCIA and MPB is to appropriately reflect changes in the market, keeping in mind the guiding principles of bundled customer indifference and obligation of each customer to pay its fair share of costs. PG&E's proposed changes are articulated below:

a. Renewables Adder

The Joint Parties and PG&E agree that it is reasonable to adjust the MPB to account for RPS-eligible purchases. However, it is important to keep in mind the distinction between renewable contract costs and the short-term market value of the RPS-eligible energy from those contracts. The goal of the Indifference Amount calculation is to quantify the above-market costs within each vintaged portfolio that are stranded by customers departing from bundled service. The above-market calculation relies on comparing the cost of the portfolio to the value of the portfolio. PG&E proposes including a renewables adder in the MPB. The renewables adder would be applied to the percentage of post-2003 RPS-eligible MWhs in each vintaged portfolio. The renewables adder would be determined based on a Renewable Energy Credit (REC) index price. The renewables adder and application of the adder to post-2003 RPS-eligible MWhs are described in more detail below.

First, with respect to identifying the proper value for a renewables adder, PG&E believes that the best source for obtaining a market value will be from a RECs market, specifically, a RECs market that represents the value of renewable generation in California. Given the Commission's recent decision permitting the use of RECs for RPS compliance (*i.e.*, D.11-01-025) and based on PG&E's conversations with brokers that actively participate in the California energy markets, it is anticipated that a transparent REC market will be available by the third quarter 2011. The earliest implementation of any revised MPB calculation would be no sooner than January 1, 2012, so there is adequate time for a market to evolve. PG&E anticipates that part of the development of a RECs market will include the development of published, transparent RECs indices. In other markets that have been developed for similar types of products, such as greenhouse gas credits and offsets, indices have developed in the early stages of the market. PG&E believes that the same is likely to happen for RECs.

Thus, PG&E proposes that the value for the renewables adder be based on transparent, published RECs indices. If a transparent, published RECs index has not developed by the time a decision is issued on Phase III in this proceeding, parties could develop a negotiated value in an individual IOU's ERRA Forecast applications, if warranted, pending development of a RECs index.

The proposal to use a California REC value, based on a California RECs market, is the proper measure for valuing renewables. This is not only the best alternative of those considered, but likely the only alternative that could conceivably be supported by all parties as it provides an objective measure of the market value for renewables.

Second, PG&E's proposal is to use post-2003 renewable MWh for the vintaged indifference calculation. PG&E would not include the MWhs associated with renewable QFs in the vintaged portfolio's MPB adder. Instead, the renewable benefit associated with the renewable QF would be accounted for in the MPB used to calculate the Ongoing

CTC. This fully accounts for the renewable QFs in a manner that is consistent with the proposal being made for the vintaged portfolios and avoids the pitfalls of having costs or credits from one charge (the Ongoing CTC in this case) subsidizing or interacting with unrelated charges (the PCIA in this case). Thus, with the benefit of the renewable QFs accounted for in the Ongoing CTC, when the Ongoing CTC is subtracted from the Indifference Amount, the residual PCIA cleanly accounts for just costs associated post-2003 generation. If PG&E were to include renewable QF MWh again in the vintaged portfolios' benchmark, this would double count the renewable MWh benefits—first as an explicit adder in the Ongoing CTC benchmark but then again as an explicit adder in the MPB used to calculate the Indifference Amount. The benefits are accounted for when the Ongoing CTC is subtracted from the Indifference Amount.

b. CAISO Costs

In general, there are two categories of CAISO costs: (1) costs associated with spot market purchases; and (2) costs associated with CAISO ancillary services, grid management, neutrality, etc. PG&E's total portfolio calculation currently includes CAISO costs associated with the second category of costs, consistent with the directives in Decision 06-07-030.**[20]**

During the workshops in this proceeding, the Joint Parties asserted that the CAISO costs were driven by load and not generation and, as such, the costs would be avoided if load departed. The Joint Parties' original suggestion was to account for the inclusion of these costs in the total portfolio by adjusting the MPB.

PG&E agrees that most, if not all, of the CAISO costs are driven by load thus should not be considered stranded when load departs. PG&E proposes to simply exclude all CAISO costs from the total portfolio calculation used in the Indifference Amount methodology. This is an efficient solution and reduces the administrative burden of calculating the Indifference Amount and PCIA.

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[20] *See* Decision 06-07-030, Appendix 3, Items 19-20.

c. Peak and Off-Peak Weight to Reflect Generation Profile

Currently, the MPB is weighted based on the number of peak and off-peak hours in the year. The Joint Parties have proposed a weighting that aligns with the load shape, which would increase the weighting of the on-peak portion of the market price and lower the weighting of the off-peak price.

PG&E agrees that there should be a modification of the weighting factor. However, rather than basing the weighting factor on load, the weighting factor should reflect the generation profile in the portfolio. PG&E proposes that the MPB weighting be based on the generation profile, consistent with the profile underlying the total portfolio cost. A preliminary calculation of the change in weighting indicates the weighting for peak and off-peak will be approximately 65/35 percent, respectively. Actual results will depend on the generation mix that is included in the forecast and the weighting will be updated in PG&E's annual Energy Resource Recovery Account (ERRA) forecast proceeding. For administrative ease, PG&E suggests that only one weighting factor be calculated and applied to all vintages rather than attempting to calculate a specific weighting factor for each vintage portfolio.

2. Modify Interaction of Ongoing CTC and the PCIA in the Indifference Amount Calculation

a. Background

Decision 02-11-022 discusses the Commission's adoption of the total portfolio approach as means to accurately measure stranded costs.[21] However, since 2001, the inclusion of low-cost URG in the total portfolio calculation has been controversial and created tension between exempt customer groups and non-exempt customers.[22] This tension stems from the fact that use of the total portfolio methodology, which nets high cost resources and low cost resources together offset

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[21] D.02-11-022, pp. 24-27.

[22] "Non-exempt" customer groups include existing and new DA departing load and CCA departing load. "Exempt" customers include municipal departing load and continuous DA customers.

not just CDWR stranded costs but also costs related to the Ongoing CTC. Costs recovered through the Ongoing CTC are governed by statute, are calculated independently from the PCIA, and are intended to be the same for bundled and departing customers in the same class.

PG&E believes the non-exempt 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. 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. Decision 05-12-045 in PG&E's 2006 ERRA Forecast proceeding specifically addressed the issue of a direct offset by prohibiting a total portfolio Ongoing CTC calculation and ordering that only one Ongoing CTC calculation be implemented and that it be based on a statutory calculation. This decision also directed how negative above-market results are to be handled, with respect to the statutorily calculated Ongoing CTC. The decision did not allow negative Ongoing CTC amounts to offset other components of the CRS.

In response to Decision 12-05-045 prohibitions on a direct Ongoing CTC offset, 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. Thus, rather than a direct offset, the offset was indirect and implemented by providing a credit on non-exempt customers bill through the negative rate.

One consideration that should have been more thoroughly examined is the effect the negative PCIA has on bundled customer indifference. If non-exempt customers were to remain on bundled service, they would pay the Ongoing CTC regardless of whether the costs for CDWR contracts (or new generation resources) were above or below market. The same should be true if they leave bundled service. That is, regardless of whether there are stranded costs associated with CDWR contracts (or new generation resources), the customers should be obligated to pay the full amount for their Ongoing CTC pursuant to the statutory requirements.[23] 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 contravenes Pub. Util. Code Section 367(a) and Decision 05-12-045.[24]

Below, PG&E describes the inequity in the Indifference Amount calculation methodology and proposes a simple remedy.

b. PG&E's Proposal

The current Indifference Amount calculation provides that:

- Indifference Amount = Ongoing CTC + PCIA
- If the Indifference Amount is negative (*i.e.,* the total portfolio costs are less than the market value of the portfolio), then the Indifference Amount is set to zero in the equation so that:
- Ongoing CTC + PCIA = 0
- Therefore, Ongoing CTC = - PCIA

Non-exempt customers pay the PCIA and Ongoing CTC, so their net payment in this situation would be zero. In situations where the Indifference Amount is greater than zero but less than the Ongoing CTC, non-exempt customers still benefit from a partial offset to their Ongoing CTC. Exempt customers only pay the Ongoing CTC, and because they do not receive any offsetting negative credit, the net result is a net positive Ongoing CTC payment. Thus, in this situation, exempt and non-exempt customers are treated differently. In addition, 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.

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[23] The statutory requirement for recovery of the Ongoing CTC are articulated in Public Utilities Code Section 367(a) whereas statutory requirements for the recovery of CDWR and post-2003 contract costs are governed by Public Utilities Code 366.1(d).

[24] D.06-12-045, OP 6.

A very simple modification will correct the logical flaw in the current indifference calculation. The calculation would be exactly the same but the constraint could be different:

- Indifference Amount = Ongoing CTC + PCIA
- If Indifference <= Ongoing CTC, then
- PCIA = 0
- Indifference – Ongoing CTC is tracked in NIAMA

PG&E's proposal results in fair and equal treatment for all affected customers and will rationalize the litigation arguments parties are motivated to make, some of which include requesting their customers have an option to choose to be non-exempt from the PCIA.

F. Conclusion

PG&E's proposals to modify the MPB are reasonable in light of the current market and fairly reflect some of the critiques parties had made to the methodology adopted to value PG&E's generation portfolio. In addition, PG&E's proposal to modify the indifference calculation's logical relationship better ensures bundled customers remain indifferent yet still allows departing customers to capture below market results by tracking negative PCIA results in NIAMA for use in offsetting future positive PCIA results. This outcome is fair and equitable and preserves bundled customer indifference in that all customers equally contribute to the Ongoing CTC obligations regardless of their status—exempt, non-exempt, or bundled.

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CHAPTER 2

TRANSITIONAL BUNDLED SERVICE RATES

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TRANSITIONAL BUNDLED SERVICE RATES

A. Introduction

On January 14, 2002, the California Public Utilities Commission (CPUC or Commission) instituted Rulemaking 02-01-011 to consider various pending implementation issues concerning the suspension of Direct Access (DA). Among the issues considered was the rate to be paid by customers returning from DA service to bundled utility service. This rate was referred to as the Transitional Bundled Service (TBS) rate. On June 23, 2003, PG&E submitted its first TBS rate via its Transitional Bundled Commodity Cost (TBCC) schedule. PG&E's TBCC schedule set forth the recommended methodology for determining the rate to be paid by DA customers who elect temporary bundled service (i.e., during a "safe harbor" period), as well as DA customers who provide six months' notice to return to bundled portfolio service, but who return to bundled service during the 6-month notice period.

B. Description of Existing TBS Rate Structure

Schedule TBCC sets forth the measures necessary to identify and apply the short-term power costs to the bills of DA customers returning to bundled service. Commission Decision 03-05-034 requires that "safe harbor" DA customers (i.e., those returning to bundled service temporarily while the customer looks for another Electric Service Provider from which to receive DA service) and those customers taking bundled service prior to completion of the 6-month advance notice requirement to pay a commodity price indexed to the California Independent System Operator (CAISO) Hourly Integrated Forward Market (IFM) Locational Marginal Price (LMP), as well as administrative, ancillary services, grid management, unaccounted for energy, and other costs. In combination, these charges form the TBS rate included in the TBCC schedule that is charged to these returning DA customers. The TBS rate was developed to ensure bundled customers' indifference by requiring returning DA customers to pay the incremental commodity costs associated with their return to bundled service.

Since the original schedule TBCC was filed on June 23, 2003, it has been modified a number of times as a result of the following Commission resolutions and decisions:

(a) Resolution E-3843, dated December 4, 2003 – Approved with modifications PG&E Advice Letter (AL) 2393-E that incorporated tariff changes to implement the rules governing the rights and obligations of DA customers to switch between bundled and DA service. PG&E made the required modification in AL 2393-E-A filed December 11, 2003.

(b) Decision 04-01-013, dated January 8, 2004 – Adopted the CAISO 10 minute Ex-Post Incremental price as the applicable proxy. PG&E filed AL 2393-E-B dated February 5, 2004 to implement this decision.

(c) Letter from Paul Clanon, Director at the Energy Division, dated March 19, 2004 – Approved AL 2393-E-C dated February 26, 2004, changing the timing as to when PG&E downloads the final posted CAISO Ex-Post Prices.

(d) Letter from Julie Fitch, Director at the Energy Division, dated February 25, 2009 – Approved AL 3175-E, dated December 7, 2007, which revised schedule TBCC to align the rates with the CAISO's Market Redesign and Technology Upgrade changes.

Since April 1, 2009, the Market Redesign and Technology Upgrade (MRTU) implementation date, the TBCC prices are now based on a formula that was implemented following the launch of MRTU. The formula is as follows:

The hourly market price (at the transmission/distribution interface) shall consist of the CAISO hourly IFM LMP for the PG&E's Utility Distribution Company (UDC) control Area (LAP_PGAE), multiplied by an allowance for Unaccounted for Energy (UFE), plus an allowance for Ancillary Services (A/S) and the CAISO Grid Management Charges (GMC).

$$MP_{\text{day n, hr}} = \text{IFM LMP}_{\text{LAP PGAE, day n, hr}} * UFE + AS_{\text{day n, hr}} + GMC$$

Hourly TBCC prices applicable to customers served at each voltage level are then equal to the hourly market price determined above, multiplied by the appropriate distribution loss factor (DLF) and a factor for franchise fees and uncollectibles (FFU).

$$TBCC_{\text{day n, hr}} = MP_{\text{day n, hr}} * DLF * FFU$$

The charge for a returning DA customer is equal to the product of the customer's actual usage and the TBCC schedule commodity price (by time-of-use period as appropriate).

C. PG&E's Proposed Revisions to the TBS Rate Structure

As discussed during the December 2010 and January 2011 workshops in this proceeding, PG&E proposes that the TBS rate calculation be adjusted to correspond to the changes made to the Power Charge Indifference Adjustment (PCIA). This was one area where all parties appeared to reach consensus during the workshops.

With respect to PG&E's proposals for changing the PCIA described in Chapter 1, there would need to be a corresponding adjustment to the TBS rate to include a Renewable Portfolio Standard (RPS) resource adder to the Market Price Benchmark (MPB). To the extent that the MPB is updated to include an RPS-resource adder, this update should be reflected in the TBS rate as well. PG&E proposes that the RPS-resource adder for the most current vintage be used for the TBS rate.

D. Conclusion

All parties appear to agree that updating the TBS rate is appropriate and that the changes should reflect the capacity and RPS-resource adder adjustments that may be adopted as a part of a revised PCIA methodology. To implement the changes to the TBS rate, PG&E recommends the inclusion of an RPS-resource adder, reflecting the most current vintage, which would be expressed in dollar per megawatt-hour numbers.

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CHAPTER 3

SWITCHING RULES

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A. Background

Direct access (DA) service was authorized by statute in the mid-1990s and commenced in 1998. Initially, bundled customers could elect to receive DA service from an Electric Service Provider (ESP). In 2001, pursuant to Governor's Proclamation of January 17, 2001, and Assembly Bill No. 1, the California Public Utilities Commission (CPUC or Commission) issued Decision 01-09-060, suspending the right to enter into new contracts or agreements for DA after September 20, 2001.

On January 14, 2002, the CPUC instituted Rulemaking 02-01-011 to consider various pending implementation issues concerning the suspension of DA. In Decision 02-03-055, the Commission adopted an exemption to the suspension requirements of Decision 01-09-060 by permitting contract renewals and assignments under which existing DA customers could choose a new ESP and thus receive DA service, even if they had returned to bundled service after September 20, 2001. This exemption is referred to as the "switching exemption."

In 2009, the California Legislature enacted Senate Bill (SB) 695 (Stats. 2009, ch. 337), which provides for the limited re-opening of DA. SB 695 directed the Commission to allow certain customers up to specified levels to elect DA service and to "review and, if appropriate, modify its currently effective rules governing direct transactions . . . ."[1]

In Decision 10-03-022, the Commission authorized increased limits for DA transactions. Effective April 11, 2010, all qualifying customers are eligible to take DA service, up to the new maximum cap. The increased DA allowances are phased in over a 4-year period, subject to annual caps of the maximum DA increase allowed each year. Otherwise, DA remains suspended, consistent with SB 695. Decision 10-03-022 only addressed those implementation issues that needed to be resolved in order to begin the process of new enrollments of DA

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[1] Public Utilities Code § 365.1(b).

load effective April 11, 2010. Additional issues that relate to SB 695 implementation are now being addressed in this proceeding.

B. Description of Existing Switching Rules

Under the existing DA rules, former DA customers currently receiving bundled utility service must provide 6-months notice in order to leave bundled utility service. The same 6-month notice requirement applies to DA customers who return to bundled service. In addition, a DA customer returning to bundled service must commit to stay on bundled service for at least a 3-year period after returning.

The Commission opted to require a 6-month notice period requirement for DA customers that elect to switch back to DA in order to allow the utility to adjust its procurement planning for the departure of that customer.[2] Moreover, the CPUC concluded that a 6-month notice was reasonable for returning DA customers to request to receive the bundled rate. If the DA customer returns to bundled service before the 6-month waiting period expires, the customer is required to pay the applicable spot market price which is reflected in the Transitional Bundled Service rate, whether it is higher or lower than the bundled rate.[3] Once the 6-month waiting period has elapsed, the DA customer will begin to pay the bundled portfolio rate, whether it is higher or lower than spot prices. The Commission also determined that it was appropriate for the customer returning to bundled service to remain on bundled service for a minimum of three years because "a three-year minimum term commitment to bundled service is the shortest period that is sufficient to adequately plan to serve bundled customers and to eliminate the potential for DA customers to base a gaming strategy on anticipated seasonal pricing patterns."[4]

In adopting these requirements, the Commission considered the following principles:

(a) DA customers should not have the indiscriminate ability to come and go from bundled service without regard to the cost-shifting effects that may result. Decision 02-11-022 adopted principles of no cost shifting.

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[2] D.03-05-034, Finding of Fact (FOF) 14.

[3] D.03-05-034, Ordering Paragraph (OP) 12.

[4] D.03-05-034, FOF 12.

Consistent with these principles, costs incurred on behalf of DA customers returning to bundled service must not be shifted to remaining bundled customers if the customer subsequently switches back to DA.

(b) Restrictions on DA customers' switching options should correspond to the level of commitment that the DA customer elects to make upon return to bundled service. For example, a customer switching to bundled service merely on a temporary basis while changing ESPs to another should not be obligated to remain on bundled service for an extended period. However, such a transient customer is not entitled to benefit from the price stability offered by the bundled portfolio. On the other hand, a customer that returns to bundled service to obtain price stability should be obligated to remain on bundled service for an appropriate minimum commitment in order to avoid gaming, cream skimming, or cost shifting to other bundled customers.

(c) As a general principle, the minimum commitment term should bear some relationship to the duration of contractual supply commitments underlying the bundled portfolio. The potential exists for cost shifting to occur if DA customers are permitted to abandon bundled service at will without any responsibility for the ongoing costs that the utility may incur under multi-year contracts that were undertaken to serve the DA customer, returning as part of bundled load.

(d) If DA customers were permitted to depart bundled service without restriction, they could leave long-term supply commitments stranded, and thereby shift costs to the remaining bundled customers. When market prices are high, DA customers would have an incentive to return to bundled service and potentially cause higher costs to be incurred as new long-term contracts are signed. Conversely, when market prices decline, DA customers would have the incentive to switch back to DA. When prices are low, it is harder for the utility to recover a reasonable portion of the contract costs.

(e) In practice, the utility procures a mix of short-term, intermediate, and long-term contracts to balance portfolio cost with supply reliability. The contract terms take into account customer growth, and also seasonal demand fluctuations. Hence, the CPUC adopted, as an initial commitment, a 3-year minimum period for returning DA customers to remain on bundled service. This 3-year period was a reasonable balance between parties' conflicting positions proposing either a shorter or longer commitment period.

(f) The advance notice and minimum term commitment requirements together are intended to guard against arbitrage or other gaming practices that could be detrimental to bundled customers. Either the customer will be required to remain on bundled service for a sufficient period of time to compensate for the long-term portfolio obligations, or in the case of the "safe-harbor" option, the customer will pay a rate that fully compensates the utility for its incremental short-term purchases of power incurred to serve returning DA load. Moreover, the "safe-harbor" customer will be limited to a stay of only 60 days on bundled service. Bundled customers should not be harmed or put at risk for higher costs, and DA customers should not be getting a "free" benefit.

(g) In the event that a customer intends to return to DA service after the 3-year commitment period, the customer should give the utility sufficient advance notice of its impending departure so that appropriate adjustments can be made in prospective procurement of power to serve bundled customers, and to minimize stranded costs. If the DA customer sought to terminate its bundled service commitment earlier than the minimum prescribed term or without giving adequate advance notice, the customer should be assessed an appropriate surcharge for the stranded costs resulting from the customer's early departure.

C. PG&E's Proposed Revisions to the Switching Rules

1. Six (6) Month Notice for Bundled Customers Departing for DA Service (No Change)

Switching customers from bundled to DA service involves a number of administrative requirements and processes. First, the current process of managing customer switches from bundled service to DA is through the management of incoming Notices of Intent (NOI) supplied by the customer. This process entails the validation of the incoming forms and, in some cases, the clarification/correction of those forms. Based on historical experience with NOIs, Pacific Gas and Electric Company (PG&E) has determined that this process often takes about 30 business days (i.e., 45 calendar days) to complete. The Commission has acknowledged this administrative period.[5]

Second, monthly Resource Adequacy (RA) filings must be adjusted to reflect customers electing to switch to DA. The CPUC's current RA process requires that parties file their monthly RA updates two months ahead of the trade month.[6] But before that filing can be prepared accurately, PG&E must first resolve any DA Service Request (DASR) discrepancies, a process that can take up to 20 calendar days. Moreover, PG&E switches customers on their meter read date. PG&E must wait for the next meter read date after initially processing a valid DASR. This waiting period may require up to 30 calendar days. Thus, the RA adjustment process requires about four (4) months to ensure that DA transactions are accurately reflected in month-ahead RA requirements. This process cannot be performed concurrently with the NOI process as RA adjustments can only be made *after* it has been confirmed which customers are eligible to switch.

Third, when there are significant changes to its portfolio from customer departures, PG&E must review and adjust its mix of short-term and intermediate-term contracts to balance portfolio cost with supply reliability.

For these reasons, PG&E recommends that the current six (6) month advance notice remain the rule for prospective departing DA customers.

2. Six (6) Month Notice for DA Customers Returning to Bundled Service (No Change)

Because ESPs have similar obligations as IOUs (*e.g.*, administrative implementation, RA compliance filings), the notice period for customers returning from DA to bundled service should also be six (6) months. To date, no party has suggested that notice requirements should be different for departing and returning customers.

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[5] See Paul Clanon December 13, 2010 letter to Janet S. Combs.

[6] See Load Forecast and Month-Ahead filing dates for 2011 RA Compliance Table in Section 2 in CPUC 2011 RA Filing Guide at following link: http://www.cpuc.ca.gov/NR/rdonlyres/264CD8F6-30CE-4433-B233-3C6652D33957/0/2011RAGuideFinal8202010.doc.

3. Eighteen (18) Month Minimum Term Commitment for DA Customers Returning to Bundled Service (Change)

The utilities and the Commission have expressed concern that allowing a *de minimis* period of time for a customer to stay on bundled service could invite seasonal gaming by customers and their ESPs. The notice and minimum term commitment requirements are intended to guard against gaming practices that would result in DA customers freely switching back and forth between bundled and DA service to capture the lowest prices. This type of arbitrage could be detrimental to bundled customers. Either the customer should be required to remain on bundled service for a sufficient period of time to compensate for the long-term portfolio obligations, or in the case of the "safe-harbor" option, the customer should pay a rate that fully compensates the utility for its incremental short-term purchases of power incurred to serve the returning customer. In addition, the utility procures a mix of short-term, intermediate, and long-term contracts to balance portfolio cost with supply reliability. To the extent that a DA customer returns to bundled service, and the utility procures resources to meet the customers load, the customer should be required to remain on bundled service for a sufficient amount of time to reflect adjustments to the utility's short-term and intermediate term procurement on behalf of the returning customer.

In order to achieve a balance between customer flexibility and concerns with gaming and resource procurement, PG&E is proposing an eighteen (18) month minimum term commitment for returning customers. Eighteen months strikes a reasonable balance between PG&E's need to manage its long-term procurement obligations and the desires of customers to switch back to DA, and ensures that the customer is not attempting to take advantage of any seasonal of cyclical changes in the market.

PG&E believes that the minimum term commitment switching rule should apply equally to DA and Community Choice Aggregation customers.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

SECURITY REQUIREMENTS

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SECURITY REQUIREMENTS

A. Introduction

Pacific Gas and Electric Company (PG&E) provides this testimony in support of its position regarding the appropriate security requirements for Electric Service Providers (ESP). Consistent with the Administrative Law Judge's Ruling Amending the Procedural Schedule, issued January 7, 2011, this testimony does not address legal matters related to the ESP security requirements. Rather, this testimony focuses on factual matters related to the prudency of and methodology for the amount of security that should be required from ESPs.

This chapter begins by providing background on credit risk and how it is evaluated, followed by a discussion of actual risks faced by customers and the investor-owned utilities (IOU) in the event of an ESP default. It also includes a description of industry risk management practices and trends, as well as a brief discussion regarding the appropriate bond amount calculation.

PG&E believes that there should be a single set of rules that apply to all load-serving entities. Therefore, there are similarities between what is discussed in this testimony and what was previously discussed in the Community Choice Aggregation (CCA) proceeding (*i.e.*, Rulemaking 03-10-003).

B. Background on Credit Risk Components

An ESP, similar to other counterparties, poses credit risk to the IOU in situations where the ESP defaults or otherwise ceases service and the ESP's customers are involuntarily returned to the IOU at a time when market rates are higher than bundled electric rates. Below, PG&E describes three elements considered when evaluating counterparty credit risks: counterparty creditworthiness, credit risk exposure components and product risks.

1. Counterparty Creditworthiness

The first step in assessing counterparty risk is the evaluation of the creditworthiness or financial strength of the counterparty. In this regard, most entities evaluate the details of an audited financial statement of the counterparty for trends in profitability, size and type of assets owned, and the amount of short- and long-term debt, among other factors. This evaluation is performed with the intent to evaluate the strength of the counterparty's business. The process and methodology used to assess financial strength will vary among parties in the commodities or financial markets and are proprietary to each entity. The appetite for risk is also tied to the level of risk tolerances of an organization through its policies and procedures. Estimating the prudent practices of the counterparty's proprietary risk management processes, controls, hedging practices, and concentration risk to a particular business sector, product type, and other counterparties can also be considered when evaluating a counterparty's creditworthiness.

An ESP creditworthiness evaluation depends highly on the financial strength of the ESP, the ESP's parent, or the ESP's third-party guarantor. An entity without financial support or sufficient net worth will typically not find counterparties willing to extend any unsecured credit limit, or access security products such as letters of credit or surety bonds that are readily available. Institutions underwriting these products will generally only offer a product if it is likely that the institution will be able to recover the losses.

2. Credit Risk Exposure Components

For procurement activities, executed transactions with a counterparty create several exposure categories as follows:

a. Current Exposure (CE)

This metric measures the replacement value of energy contracts on a Mark-to-Market (MtM) basis (*i.e.*, close of business estimate or published value of the remaining contract, plus accounts receivables less accounts payable). In addition, other considerations such as exposures associated with affiliates or subsidiaries that are under separate contracts, must be considered in determining total exposure, as netting of exposures may not be feasible contractually.

b. Potential Future Exposure

This risk arises from a counterparty failing to perform its obligations under the agreed-upon terms of the contract for the remaining portion of the tenure of the transaction. The entity must assess the replacement value for the period a failure may occur. For example, if a party anticipates that a counterparty within the next five days will fail to perform on a 1-year fixed price energy contract, the party has to assess how much the value of the 1-year contract may change over the five days period. Depending on whether the contract is a sell or a purchase, the estimate of potential future loss or gain varies with market price movements. In the case of purchases, the exposure is based on rising prices, which is the replacement cost if the supplier were to fail. In the case of a sell, the exposure is based on falling prices resulting in financial loss when the balance of contract is sold at a lower price. Potential Future Exposure (PFE) is typically calculated based on the estimated time to replace the contract, projected volatility associated with the product for the specified delivery period, transaction type, delivery location, and the confidence level (*e.g.*, 95 percent or 99 percent). PFE is commonly measured using the methodology similar to that proposed for the CCA bond model in Rulemaking 03-10-003, or could be based on a Monte Carlo simulations for more complex portfolios with multiple risk factors. In the case of a load-serving entity, PFE represents the risk to the IOU of replacing supplies for the involuntary return customers; for example, six or twelve months of energy supplies, Resource Adequacy (RA), renewable credits, and greenhouse gas (GHG) allowances.

c. Market Liquidity Risk

Market liquidity is based on the depth of the bids and offers and market participation levels. The spread between the bid and offer prices are typically reflective of the liquidity of the market. The bid and offer price spread may vary depending on the size of the contract or transaction type. Location, product type, and timeline can also substantially change the spread levels. For example, the market liquidity for a monthly physical index may be better than a fixed price product as the risk related to an index-based product is substantially below that of a fixed price. Basis risk also contributes to liquidity due to possible lack of generating facilities, or transmission constraints.

Different commodities also provide varied levels of market liquidity due to the nature of the infrastructure development, supply and demand, and ability to store.

d. Credit Liquidity Risk and Working Capital

Credit liquidity risk arises as a result of market risk and contractual obligations to post margin for transactions. Margin requirements will depend on rising and falling prices relative to the net position with the counterparty. To protect against such losses, counterparties typically manage collateral on the basis of the amount of credit threshold they have extended to each other contractually. When the exposure is above and beyond the credit threshold, additional collateral needs to be provided, depending on transaction type, and whether it is executed bilaterally or through exchange, the additional security may require posting from same day to within three business days.

e. Default Risk

Default risk is the probability of a counterparty to default on its financial obligations. When a counterparty defaults, the amount of claim recovered against the counterparty relative to the total claim amount is referred to as recovery rate. Default risk can be estimated based on various measures. These measures for unsecured or low credit rated counterparties will be high as the estimated recovery rate is low and the probability of default is high.

(1) Loss Given Default (LGD)

Measures the anticipated loss when counterparty defaults. This is measured based on the projected recovery rate.

(2) Expected Loss

This is a probabilistic measure and is the product of the probability of default, LGD, and the measured mean exposure.

(3) Stress Loss

Is the measure of loss at a given confidence requirement and a specific period of measurement (*e.g.*, 95 percent confidence within one year). For example, the loss for a 1-year agreement is measured by calculating the exposure on the basis of combination of CE and PFE for 1-year horizon at 95 percent confidence, and based on the probability of default of one year and LGD.

3. Product Risks

The IOUs are exposed to various product risks including the following:

a. Energy

Depending on the hedging strategies and requirements, a certain percent of any portfolio is exposed to hourly, daily, and term transactions of various durations. The price curves and liquidity levels for these products vary substantially.

b. Resource Adequacy

RA prices substantially vary seasonally and annually depending on the availability of resources.

c. Renewable Energy Compliance

Meeting California's Renewable Portfolio Standard (RPS) requirements may be difficult as the parties approach RPS compliance deadlines with remaining uncertainty around successful development of currently planned projects by IOUs or through Power Purchase Agreements with independent power producers. In addition, as the economic recovery in the United States and California continues to improve, there will be potentially additional price pressure on renewable products to meet this requirement with load growth in California and surrounding states.

d. California Air Resources Board GHG Compliance Mandate

California Air Resources Board's (CARB) implementation of the Cap and Trade program to be effective in January 2012 provides additional uncertainty for availability of GHG allowances or offsets. It is still unknown how this market will evolve over time and level of volatility and liquidity this market may have.

C. ESP Risk for IOUs and Bundled Customers

Market events causing ESPs and CCAs to default will adversely impact both the IOUs and their bundled customers. The following section describes the risks the IOUs and bundled customers will likely face in the event of defaults resulting in involuntarily returned customers.

1. Increased Capital Costs

IOUs' cash flow, planned working capital, and borrowing facilities are based on many factors ranging from infrastructure investments to hedging activities and requirements, as well as other operational considerations. Managing price volatility is a significant component of a procurement hedging plan and estimation of working capital needs. An unplanned return of Direct Access (DA) or CCA customers will pressure an IOU's working capital primarily because such failures are expected during volatile and high energy prices, when the IOU will likely need to utilize its financial facilities to manage the higher cash flow needs for its bundled customers. The additional daily borrowing needs can shift additional cost to the bundled customers, as the IOU may be forced to pay higher interest rates for its short-term borrowing activities, and be forced to seek additional credit facilities at a higher cost due to perceived risk impact of additional unplanned commitments and recovery risk.

2. GHG Compliance Risk

It is fairly uncertain how the California's GHG market will evolve over time. However, it is clear that non-compliance will likely have significant penalties. The potential secondary market costs are currently unknown should CARB auctions not provide sufficient market liquidity, when customers involuntarily return to the IOUs.

3. RPS Compliance Risk

IOUs must plan and procure for involuntary returning customers RPS requirements. Currently, the IOUs plan to meet the compliance targets using, short- and long-term contracts to ensure compliance. An unplanned ESP or CCA default would cause an IOU to be exposed to the spot market for RPS resources for compliance. The potential costs are unknown, particularly for a large un-hedged renewables position.

4. Unsecured Credit Limit Extended to the IOUs by Suppliers, Merchants and Financial Institutions

As discussed further below, not all unsecured credit limits extended to the IOUs are tied to its external rating. There are bilateral agreements that provide either party the flexibility to use material adverse conditions to eliminate any extended unsecured credit limit and require additional margin, further reducing the credit facilities of IOUs. A substantial default by an ESP or CCA may cause some counterparties to reduce or eliminate unsecured credit limit benefits of the IOUs. Such action requires the IOU to post collateral within three business days for potentially the entire outstanding exposure.

5. Potential Negative Outlook or Lower Financial Rating Increases Cost of Borrowing and Credit Facilities of IOUs

An IOU's credit rating by external agencies significantly affects its ability to borrow and the costs associated with borrowing. The external agencies, other market analysts, and commercial banks closely monitor the IOU's regulatory framework and scrutinize the IOU's ability to recover its costs through rates and the time it may take to recover such costs. The credit agencies will make their evaluation by asking questions such as:

(a) Can involuntary returned customers pay the market rate?

(b) If customers cannot, then what are the chances of the IOU being required to offer bundled rate sooner than the expected period of six months due to the severity of rise in market prices and impact it may have on a community?

(c) Will the size of involuntary returns combined with market prices allow the IOU to raise rates in a timely manner to meet its additional procurement, hedging, and compliance costs?

(d) Does the IOU have sufficient liquidity to manage the market turmoil?

To the extent that the IOU's responses to these types of questions raises concerns for the rating agencies, there is a potential for a negative outlook or potential rating downgrade. Any negative outlook or perceived potential for rating downgrade will challenge the IOU's ability to meet its liquidity needs or will require it to meet its liquidity needs at increasingly higher costs.

D. Industry Practices for Managing Counterparty Risk

It is a common practice in the energy industry to request security on the basis of current and future exposure. Security requirements are not unique to the DA or CCA programs. The following section discusses some of current market practices that are common contractual terms for credit risk and security requirements. Requesting security and determining the amount or process to assess security needs is a general practice. Numerous counterparties comply with these requirements and are able to obtain necessary and commercially viable products to secure transactions.

1. Relevant Market Contractual Practices for Managing Counterparty Risk

Depending on the market and entities participating in that market, security requirements may vary. For example, security requirements for futures or swap contracts executed through exchanges are different from those executed bilaterally. Similarly, the credit collateral requirements for transactions through the California Independent System Operator (CAISO) are differently assessed than the same products traded bilaterally with counterparties through financial or physical enabling agreements.

a. Bilateral Enabling Agreements

The majority of the bilateral physical contracts in the power market are executed through confirms to an amended Edison Electric Institute or Western Systems Power Pool (WSPP) master enabling agreements. WSPP credit terms are typically negotiated through an amendment to the WSPP standard form and parties specify the additional credit terms and requirements. Similarly, financial agreements are transacted through confirms to the International Swaps and Derivatives Association master agreements negotiated by parties. These contracts typically include provisions that describe the level of unsecured credit limits, the financial rating needs, or specific term that describe the conditions under which collateral calls are made. However, all contracts address the following components and obligations:

(1) Posting of MtM

An amount determined by means of a MtM calculation to be posted by either party when the current exposure is beyond the specified credit limit threshold.

(2) Independent Amount

An amount determined by parties used above and beyond the MtM necessary to post at all time regardless of exposure levels. This amount varies based on the creditworthiness of counterparties and internal policies of the party requiring the Independent Amount (IA). It may be calculated based on volume of transactions under consideration over a specific term. For example, IA may cover 10, 20 or 30 days of PFE (at 95 percent confidence interval) for a one month physical transaction, depending on counterparty's creditworthiness.

(3) Adverse Condition Clause

Some market participants do not agree to any pre-established credit threshold levels and instead negotiate terms that allow each party to provide at its sole discretion an unsecured limit it deems appropriate. As such when a party determines that there exists an adverse condition that may hinder the counterparty's ability to perform on its obligation, it can request for security to offset the exposure, based on the agreed upon method of calculation outlined in the master agreement.

b. Renewable Contracts

IOUs in California generally require development security for new projects and delivery term security for new and existing projects. In PG&E's case, delivery term security may be as much as one year of revenues for that project.

c. Engineering, Procurement and Construction Agreements

It is not uncommon in the construction business to require up to 100 percent of project value in performance bonds. Various levels of security amounts may be requested in addition to the performance bond in order to cover sub-contractor payment risks, additional costs incurred due to completion delays (to the extent the contract specifies this). The total security requirement will typically vary on the basis of the:

- Complexity of projects
- Equipments to be procured or installed

- Level of construction challenges and permitting requirements
- Developer experience and creditworthiness
- Milestone payment structure, which impacts exposure if any advance payments are involved

d. Exchanges and Clearing Entities

Exchanges and clearing entities require both an initial and maintenance security. It is important to understand that individual brokerage firms can, and in many cases do, require margin that is higher than the exchange requirements. Additionally, margin requirements may vary from brokerage firm to brokerage firm. Furthermore, a brokerage firm can increase its "house" margin requirements at any time without providing advance notice, and such increases could result in a margin call.

e. California Independent System Operator

The CAISO has various levels of security requirements from parties depending on level of procurement needs, financial strength and rating, and entity type (governmental or private sector). The maximum amount of unsecured credit limit that the CAISO extends to the highest rated entities based on its assessment is $50.0 million. The CAISO requires 100 percent security for its financial products such as Congestion Revenue Rights. Security requirement is based on the assessed creditworthiness, past procurement volume, and projected Estimated Aggregate Liability as calculated by the CAISO.

E. Commercially Available Security Products

Many entities in the energy industry are required to post security. Entities, including ESPs and CCAs, will have access to the following forms of security depending on their level of their creditworthiness or that of their guarantor.

1. Letters of Credit Providers

Most commercial banks can provide a letter of credit. However, the beneficiary may not find all the banks creditworthy to issue the Letters of Credit (LOC). For example, Table 4-1 below shows a list of commercial banks that can provide LOCs acceptable for New York Mercantile Exchange

(NYMEX) transactions as posted on the CME Group[1] website related to credit security requirements. In addition, the IOUs and other market participants will have their preferred banks that they would find acceptable issuer of the LOC.

[1] CME Group is comprised of four Designated Contract Markets: Chicago Mercantile Exchange (CME), Chicago Board of Trade, NYMEX and Commodity Exchange.

TABLE 4-1
PACIFIC GAS AND ELECTRIC COMPANY
LIST OF POTENTIAL LOC PROVIDERS ACCEPTABLE TO CMEGROUP

Line No.	Bank Name	Branch	Country
1	Australia and New Zealand Banking Group Ltd.	NY	Australia
2	Banco Santander Central Hispano, S.A.	NY	Spain
3	Bank of America, NT&SA	CHGO	United States
4	Bank of China Ltd.	New York	China
5	Bank of Montreal	NY	Canada
7	Bank of New York Mellon	NY	United States
6	Bank of Nova Scotia	NY	Canada
7	Bank of Tokyo-Mitsubishi UFJ	CHGO	Japan
8	Bank of Tokyo-Mitsubishi UFJ	NY	Japan
9	BBVA S.A.	NY	Spain
10	BNP Paribas	NY	France
11	Caixa Geral de Depositos	NY	Portugal
12	Citibank N.A.	NY	United States
13	CoBank	Denver	United States
14	Comerica Bank	MI	United States
15	Commerzbank	NY	Germany
16	Credit Agricole Corporate and Investment Bank	NY	France
17	Credit Industriel et Commercial	NY	France
18	Danske Bank	NY	Denmark
19	DBS Bank Ltd.	LA	Singapore
20	Deutsche Bank AG	NY	Germany
21	DnB NOR Bank ASA	NY	Norway
22	DZ Bank AG	NY	Germany
23	Fifth Third Bank	Cincinnati	United States
24	Harris Trust & Savings	CHGO	United States
25	HSBC Bank USA	NY	United Kingdom
26	Intesa Sanpaolo S.p.A.	NY	Italy
27	JP Morgan Chase Bank	NY	United States
28	JP Morgan Chase Bank	CHGO	United States
29	KBC Bank	NY	Belgium
30	Lloyds Bank TSB	NY	United Kingdom
31	Mitsubishi UFJ Trust and Banking Corp.	NY	Japan
32	Mizuho Bank	NY	Japan
33	Natixis	NY	France
34	Norddeutsche Landesbank	NY	Germany
35	The Northern Trust Company	CHGO	United States
36	OCBC Bank	NY	Singapore
37	Rabobank Nederland	NY	Netherlands
38	Royal Bank of Canada	NY	Canada
39	The Royal Bank of Scotland N.V.	CHGO	Scotland
40	Societe Generale	NY	France
41	Standard Chartered Bank	NY	United Kingdom
42	Svenska Handelsbanken	NY	Sweden
43	UBS AG	NY	Switzerland
44	United Overseas Bank Ltd.	NY	Singapore
45	U.S. Bank National Association	Seattle	United States
46	Wells Fargo Bank, N.A.	Winston-Salem	United States
47	Wells Fargo Bank, N.A.	San Francisco	United States

2. Bonds Providers

Table 4-2 below provides a list of the top 25 bond providers based on premiums written. The surety bond underwriters try to recover cost from the client for which they have issued the bond. For this reason, bond prices and availability will depend on the client's creditworthiness, complexity of the business, and term of the guarantee.

TABLE 4-2
PACIFIC GAS AND ELECTRIC COMPANY
25 LARGEST SURETY COMPANIES

Ranking	Group/Company Name	Country
1	Travelers Bond	United States
2	Liberty Mutual Insurance Group	United States
3	Zurich Insurance Group	Switzerland
4	CNA Insurance Group	United States
5	Chubb & Son Inc. Group	United States
6	Hartford Fire & Casualty Group	United States
7	HCC Surety Group	United States
8	International Fidelity Insurance Co	United States
9	Ace Ltd Group	Bermuda
10	The Hanover Insurance Group	United States
11	Great American Insurance Companies	United States
12	NAS Surety Group (Part of Swissre)	Bermuda
13	Lexon/Bondsafeguard Insurance Companies	United States
14	Arch Capital Group	United States
15	Chartis Group	United States
16	RLI Insurance Group	United States
17	Westfield Group	United States
18	INSCO DICO Group	United States
19	Merchants Bonding Co Group	United States
20	Cincinnati Financial Group	United States
21	WR Berkley Corp Group	United States
22	Alleghany Group	United States
23	Suretec Insurance Co	United States
24	Old Republic Group	United States
25	Proalliance Group	United States

3. Cash Collateral

Cash collateral may be posted directly with a party or to a third-party escrow account. If cash is posted to an escrow account, both parties need to agree to the rating and creditworthiness of the third-party entity and the covenants must be approved by all parties for the escrow account.

4. Parental or Third-Party Guarantees

If a counterparty's creditworthiness is not deemed sufficient for issuance of a guarantee, then the party may provide such guarantee through an acceptable parent guaranty or a through the guarantee provided by a third party. The difference between a LOC and a guarantee is that an LOC is an irrevocable and unconditional, where as a guarantee may require litigation in court and poses collection enforcement risk. However, an acceptable guarantee may just be sufficient for the purposes of posting the security requirement or by the surety bond or LOC issuer.

F. Prudency of the Bond Model Proposed in CCA Proceeding

The discussion in this testimony applies equally to both CCAs and ESPs as a default by either type of entity can have severe impact on IOUs and bundled customers. As discussed above, the levels of unsecured exposure is a major risk factor. Unsecured CCA and ESP programs may be harmful to the financial strength of the IOUs, especially at a time when the IOUs must also comply with renewable energy requirements and other infrastructure developments to support these resources, and to bundled customers. The bond model proposed in the CCA proceeding (R.03-10-003) provides an appropriate, commercially feasible framework for quantifying future exposure risk for these programs. The proposed model provides for an appropriate measure for maintaining prudent level of security to protect the IOUs' bundled customer from involuntary DA or CCA customer returns. PG&E has amended its position on the frequency of recalculating the bond model from one year down to six months. However, for the most part, the CCA proceeding bond model is an appropriate framework for the following reasons:

1. It is PG&E's understanding that the prudency of the methodology is not under question. The model and approach to assessing risk has been proven through various workshops and by experts as an accurate approach to estimate potential risk of a 1-year contract every six months. The details of the bond model and re-entry fee calculations are provided in Attachment 1, which were submitted to the Commission as Settlement Agreement, Attachment A in Rulemaking 03-10-003, on September 8, 2010.
2. The IOUs have provided sufficient description for the sources available to any party to access market prices and volatilities. This information is not

free and is subscription based. However, there should be no doubt about its availability to anyone in the public. The name and contact of these providers are provided below in Table 4-3.

TABLE 4-3
PACIFIC GAS AND ELECTRIC COMPANY
POWER DATA PROVIDERS

Line No.	Company	Contact Information	Product
1	ICAP	Jeff Teague (919) 969-9779 jeff.teague@us.icapenergy.com	Power Forwards
2	Prebon	Ben Preston (201) 557-5904 bpreston@tpinformation.com	Power Forwards
3	Amerex	Melissa Gist (281) 340-5206 mgist@amerexenergy.com	Power Forwards
4	Tullett	Michael Esposito (212) 208-5876 MEsposito@tullett.com	Power Forwards
5	ICE	Ed Fraim (646) 733-5018 Ed.Fraim@theice.com	Power Forwards
6	Amerex	Melissa Gist (281) 340-5206 mgist@amerexenergy.com	Power Volatility

3. For the purposes of calculation of the bond amount, the model does not have to use implied volatilities provided by the brokers for points where implied volatilities are not readily available. Instead the parties can use the historical volatilities to be calculated based on the historical data for the forward curves.
4. The 6-month period for recalculating the bond is administratively more beneficial for all parties. More frequent assessment of the bond will require additional administrative resources as well as various system upgrades by all parties to accommodate quantifying security requirement, credit worthiness assessment, adjustments needed to the amount of collateral held, and communication of new margin needs. This task can be managed

with existing resources if it is recalculated semi annually. However, a more frequent assessment in the form of weekly or monthly will certainly require additional automation and staffing needs to insure appropriate amounts are calculates, disputes are resolved, amendments to the LOCs, bonds or guarantees are appropriately reflected. In addition, because the bond reassessment period is proposed to be every six months, there will be extended periods that market prices may remain below utility bundled rate and therefore, no bond will be required, even if prices were to fluctuate to levels when a security may be needed. In comparison, a daily, weekly or monthly calculation in the form of a MtM approach would have required security to be posted. Therefore, because of the unknown timing of the bond calculation and the price and volatility levels at the time of the quantification, it is difficult to predict whether the bond methodology proposed in the CCA proceeding or a MTM approach would require less security on average over time.

5. Establishing additional criteria such as posting of bond only within a 20 percent band is not consistent with industry practice and should not apply to parties that do not have access to appropriate credit support. Establishing the band will not prevent problems associated with fundamental issue of credit worthiness and whether or not a party can manage its credit liquidity in adverse market conditions. It will only delay the inevitable failure to post the required security in adverse conditions.

G. Conclusions and Recommendations

There is significant risk associated with default by ESPs and CCAs that is quantifiable and real.

(a) This risk needs to be mitigated by ESP and CCA entities and not by IOUs and the bundled customers. The issue remaining is not whether or not counterparty risk exists but rather the potential size of this risk and prudent amount of security requirement.

(b) The accurate measure for this risk is a PFE model as proposed in the CCA proceeding (R.03-10-003). The Commission needs to ensure that ESP, CCA, and bundled customers are protected under adverse market conditions.

(c) A proper security requirement is a sufficient and feasible instrument to ensure appropriate protections for all customers.

(d) The security requirements will mitigate any potential gaming of the system. It will create sufficient barrier for entities without adequate amount of assets at risk to mislead customers, inappropriately manage procurement responsibilities, and default once the market prices rise, only to return under different name and structure to resume same practices.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT A

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ATTACHMENT A

SETTLEMENT AGREEMENT IN RULEMAKING R.03-10-003

(PHASE 3 – COMMUNITY CHOICE AGGREGATION BOND PROCEEDING)

This Settlement Agreement in Phase 3 of the Community Choice Aggregation (CCA Service) rulemaking proceeding (R.03-10-003) (Agreement or Settlement Agreement) is entered into by the undersigned Parties hereto, with reference to the following:

A. <u>Parties</u>

The Parties to this Settlement Agreement are the San Joaquin Valley Power Authority (SJVPA); the City of Victorville; The Utility Reform Network (TURN); Southern California Edison Company (SCE); San Diego Gas & Electric Company (SDG&E); and Pacific Gas and Electric Company (PG&E) (collectively referred to herein as Parties or Settling Parties or individually as Party).

SJVPA is a California joint powers agency formed under the provisions of California Government Code Section 6500, *et seq.*, and was established in order to implement a CCA Service program.

The City of Victorville is a city in SCE's service area.

TURN is an independent, non-profit consumer advocacy organization that represents the interests of residential and small commercial utility customers.

SCE, SDG&E, and PG&E are investor-owned public utilities and are subject to the jurisdiction of the California Public Utilities Commission (Commission or CPUC) with respect to providing electric service to their CPUC-jurisdictional retail customers.

B. <u>Recitals</u>

The Commission opened this rulemaking on October 2, 2003 to implement certain provisions of Assembly Bill (AB) 117, which among other things authorized cities and counties to aggregate the electrical loads of customers within their jurisdictions and serve that load on an opt out basis as Community Choice Aggregators (CCAs). On December 21, 2004, the Commission issued an Order Resolving Phase 1 Issues on Pricing and Costs Attributable to Community Choice Aggregators and Related Matters; on December 16, 2005, the Commission issued a Decision Resolving Phase 2 Issues on Implementation of Community Choice Aggregation Program and Related Matters.

SJVPA submitted the first version of its CCA Service implementation plan to the Commission on January 29, 2007. As part of its registration, SJVPA was required to post a bond pursuant to Section 394.25(e). In Resolution E-4133, issued on December 24, 2007, the Commission adopted an interim bond amount for SJVPA of $100,000. PG&E applied for rehearing of Resolution E-4133, which the Commission denied in D.08-03-023. In setting this interim bond amount, the Commission stated that it would consider the bond requirements applicable to all CCAs in a formal Commission proceeding. Included in this consideration would be whether or not it was necessary to adjust SJVPA's interim bond.

On May 27, 2008, Administrative Law Judge (ALJ) Yip-Kikugawa issued a *Ruling Setting Forth Bond Requirement Phase of the Proceeding* (May 27 Ruling). Opening and reply comments pursuant to the May 27 Ruling were filed on July 14, 2008 and July 28, 2008, respectively, by the Settling Parties and others. SCE and PG&E in their reply comments requested evidentiary hearings.

On August 29, 2008, ALJ Yip-Kikugawa issued a ruling setting a prehearing conference for September 17, 2008, and held a prehearing conference as scheduled.

On October 8, 2008, ALJ Yip-Kikugawa and Assigned Commissioner Peevey issued a Ruling and Amended Scoping Memo (the Scoping Memo), which established a separate third phase of this rulemaking to address the requirements of Section 394.25(e) for CCAs, and determined the following issues should be addressed in the third phase:

1. Identification of the costs to be included in the re-entry fee to ensure there is no cost-shifting.
2. Determination of the methodology to calculate a CCA's overall bond requirement.
3. Identification and evaluation of alternatives to a bond to indemnify bundled customers from potential costs associated with return of CCA customers to utility bundled service as a result of a CCA's failure.
4. Assessment of the ability of CCAs to obtain a bond or insurance to meet their bond requirement.

The Scoping Memo adopted a procedural schedule, including a workshop to be held on November 17 and 18, 2008. Responses to the Scoping Memo were filed on November 18, 2008.

The Commission held the workshop on November 17 and 18, 2008, which was facilitated by ALJ Yip-Kikugawa. At the conclusion of the workshop, parties agreed to meet subsequently to present and address questions on their proposed bond calculation methods, and to begin settlement discussions.

On December 18, 2008 and January 15, 2009, parties and the Energy Division met at the Commission to continue the workshop discussions. The parties agreed to reconvene (without Energy Division participation) to begin settlement discussions.

Continuing settlement discussions occurred among the Settling Parties, the City and County of San Francisco (CCSF) and the County of Marin beginning on January 29, 2009.

On May 12, 2009, the Settling Parties noticed a settlement conference pursuant to Rule 12.1 of the Commission's Rules of Practice and Procedure. The Settling Parties convened the settlement conference on May 27, 2009. Participants in the settlement conference were the Settling Parties and CCSF.

The Settling Parties have evaluated the various proposals in this third phase of R.03-10-003, desire to resolve all issues related to the calculation of a CCA's bond requirement and to the calculation of re-entry fees, and have reached agreement as indicated and described in Section C of this Agreement.

C. Agreement

In consideration of the mutual obligations, covenants and conditions contained herein, the Settling Parties agree to the terms of this Agreement. Final approval of this Agreement is subject to the express condition precedent described in Section C.13 below. The Settling Parties, by signing this Agreement, acknowledge that they pledge support for Commission approval and subsequent implementation of all the provisions of this Agreement. The Settling Parties agree to perform diligently and in good faith all actions required or implied hereunder, including the execution of any other documents required to effectuate the terms of this Agreement, and the preparation of exhibits for, and presentation of witnesses at, any required hearings to obtain the approval and adoption of this Agreement by the Commission. No Settling Party will contest in this proceeding or in any other forum, or in any manner before this Commission, the recommendations contained in this Agreement. It is understood by the Settling Parties that time is of the essence in obtaining the Commission's approval of this Agreement and that each will extend its best efforts to ensure its adoption.

1. Timing of Bond Calculations, Advice Filings and Bond Postings; Forward Price Calculation

The amount of the CCA bond will be calculated twice annually: once in early November and again in early May. These calculations shall be for bonds to be posted (subject to paragraph C.12 below) by December 31 and June 30, respectively. M denotes the month when the IOU will calculate the bond amount. For CCA Service programs or phases starting in month

M+2 months (where M is not May or November), the bond calculation shall be performed using month M-1 month data, and the bond shall be for the period from the program or phase start date through the next semi-annual calculation.

The calculation starts with the same methodology and forward pricing data source that the Energy Division employs to calculate the Market Price Benchmark (MPB) applicable to the IOUs' ERRA Applications. The MPB is the weighted average of daily peak and off-peak energy prices for all trading days, in October, April, or the month of M-1 month, as applicable, for the one-year forward strip, plus Resource Adequacy (RA) value and losses.

The utilities shall calculate the gross bond amount pursuant to a formula (described below). The utilities shall submit the initial bond calculation as an advice letter filing, designated as a Tier 2 advice letter. All subsequent bond calculations shall either be submitted as a Tier 1 advice letter or a report to the Energy Division (copied to CCA parties and others on the utilities G.O. 96 list) that shall be deemed accepted unless the Energy Division suspends the advice letter/report during the review period (30 days). Subject to paragraph C.12 below, the CCA must post the bond amounts reported in the advice letter by the due date set forth in the timeline below, subject to adjustment for any detected errors, irrespective of whether the advice letter has been approved by such due date. For example, for a start date in January 2010, the CCA must post the bond amount reported in the utility's November 10 advice filing by no later than December 31, 2009, subject to adjustment for any detected errors, irrespective of whether the advice letter has been approved (actual or deemed) by December 31, 2009. In any event, the CCA's bond must be posted before CCA program implementation may begin.

Timeline:

Data Collection Month = October, April, M-1 month

Month in which bond is calculated = M

Utility filing of advice letter/report = November 10, May 10, 10th day of month M

Protests (if any) of advice letter/report = November 30, May 30, last day of month M

Deemed acceptance of advice letter/report = December 10, June 10, 10th day of month M+1

Bond Posting Date = No later than December 31, June 30, last day of month M+1

As noted above, the Forward Price will be calculated using the same methodology and forward pricing data source that the Energy Division employs to calculate the MPB applicable to the IOUs' ERRA Applications. As such, the Forward Price shall use the weighted average of daily peak and off-peak energy prices for all trading days in Month M-1 month for Months M+2 months to M+13 months, inclusive. The Forward Price is calculated as set forth below:

ffi PF ($/MWh) = Average of daily peak prices in month M-1 for Months M+2 to M+13, Inclusive

ffi OF ($/MWH) = Average of daily off-peak prices in month M-1 for Months M+2 to M+13, Inclusive

ffi PH (MWh) = Number of Peak Hours in 12 forward months

ffi OH (MWh) = Number of Off-Peak Hours in 12 forward months

ffi F ($/MWh) = Flat Forward Price = [(PF*PH) + (OF*OH)]/(PH+OH)

If the Commission modifies the MPB for purposes of establishing the CCA Service Cost Responsibility Surcharge by including a load shape adjustment in the determination of the one-year forward strip price, then the bond calculation methodology set forth in this settlement shall be modified as set forth below automatically and without further action by the Commission. All subsequent periodic calculations of CCA bond responsibility shall thereafter follow the methodology as modified below.

Use the daily peak and off-peak forward prices collected in Month M-1 months for Months M+2 months to M+13 months, inclusive. Include an adjustment to this "baseload" price to account for on-/off-peak prices together with the load shape of the CCA. The load shape of the CCA will be the weighted class average based on publicly available information. The Load Shape Adjusted Forward Price is calculated as set forth below:

- PF ($/MWh) = Average of daily peak prices in month M-1 for Months M+2 to M+13, Inclusive
- OF ($/MWH) = Average of daily off-peak prices in month M-1 for Months M+2 to M+13, Inclusive
- PL (MWh) = Estimated CCA Peak Period usage for 12 forward months
- OL (MWh) = Estimated CCA Off-Peak Period Usage for 12 forward months
- F ($/MWh) = Load Shape Adjusted Flat Forward Price = [(PF*PL) + (OF*OL)]/(PL+OL)

Notwithstanding the foregoing, a load shape adjustment will be included in the re-entry fee calculation set forth in Section C.13 below.

2. Stressed Energy Price Calculation for the CCA Bond

The Stressed Energy Price and Stress Factor shall be calculated as follows: To reflect potential volatility, use the implied volatility V for flat power. Adjust for line losses using the line loss factor L% applicable to each IOU (e.g., 106% for PG&E). Calculate a "Stressed" Energy Price for the annual strip determined in Section C.1 at the 95% confidence level, using the approach recommended by the IOUs (i.e., Black's model, as described in **Exhibit 2** hereto) but employing publicly available market data for the same trading dates used in pricing the forward strip.

- V: Implied annualized volatility for flat power delivery
- Adjust F for losses using the adopted factor as per MPB

ffi Adjusted Forward is AF = (L%)*F

ffi T = 0.5 Years

ffi Stressed Energy Price = AF * Exp(-0.5*V*V*T+V*sqrt(T)*1.64)

ffi Stress Factor = Stressed Energy Price/AF

3. RPS – Additional Flexible Compliance for Involuntarily Returned CCA Load

In the event that an involuntary return[1] of the customers of a CCA would directly cause a failure to meet applicable RPS requirements by the electric utility to whose bundled service those customers are returning, that utility may request the Commission to forbear imposing a penalty for non-compliance. The Commission may grant the utility's application upon an appropriate showing by the utility, and subject to the utility meeting its RPS requirements within the four years following the year in which the involuntary return occurred.

4. [DELETED]

5. Stressed Resource Adequacy (RA) Price Calculation for the CCA Bond

Calculate a Stressed RA Price by using the RA adder from the MPB and stressing it by the Stress Factor established in Section C.2. Assume the RA requirement is X% of the maximum customer load. The default value of X% is 115% but would be modified to account for the IOU's procurement of capacity for so-called "benefiting" customers per D.06-07-029. The 115% requirement will be reduced by the percentage of capacity procured pursuant to D.06-07-029 relative to the IOU service territory peak load.

[1] The term "involuntary return" of CCA customers is discussed in section 394.25(e) of the California Public Utilities Code and Resolution E-4133 means a return of CCA Service customers to IOU procurement service occurring not at the election of the customers but rather a cessation of service by the CCA that would result in an involuntary, and en masse, customer return to bundled service. (*See* Resolution E-4133 at 10-11.)

6. Stressed Returning CCA Bundled Generation Cost Calculation for the CCA Bond

Calculate a stressed Returning CCA Bundled Generation Cost per MWh by adding (a) the Stressed Energy Price, (b) X% times the Stressed RA Price and (c) Y% times the Stressed RPS Premium (if no forbearance granted).

ffi Stressed RA Price = As calculated in Section 5

ffi Stressed RPS Premium = As calculated in Section 4

ffi Assume the RA requirement is X% as in Section 5 and the RPS requirement is Y% as in Section 4

ffi Returning CCA Bundled Generation Cost = Stressed Energy Price + (X%)*Stressed RA Price+ (Y%)*Stressed RPS Premium

7. Stressed Bundled Generation Rate Calculation for the CCA Bond

Determine IOU's Stressed Bundled Generation Rate. This rate will be based on the actual system average bundled portfolio cost at the time of the calculation plus $10 per MWh as a "stress adder."

ffi IOU Stressed Bundled Generation Rate = System Average Bundled Gen Rate + $10 per MWh

If the Commission modifies the Market Price Benchmark for purposes of establishing the CCA Service Cost Responsibility Surcharge by including a load shape adjustment in the determination of the one-year forward strip price, then the bond calculation methodology set forth in this settlement shall be modified as set forth below automatically and without further action by the Commission. All subsequent periodic calculations of CCA bond responsibility shall thereafter follow the methodology as modified below.

The IOU's Stressed Bundled Generation rate will be based on the actual average bundled portfolio cost at the time of the calculation, adjusted for the specific CCA load customer class rates and load, plus the $10 per MWh stress adder. Assuming that the CCA load consists of rate classes A, B, etc.:

- CCA Load Shape Adjusted Bundled Gen Rate = [System Annual Average Gen Rate for Class A*Annual MWh for Class A + System Annual Average Gen Rate for Class B*Annual MWh for Class B +... for all classes]/[Annual MWh for Class A+Annual MWh for Class B+… for all classes]
- IOU Stressed Bundled Generation Rate = CCA Load Shape Adjusted Bundled Gen Rate + $10 per MWh

8. Procurement-related Cost Exposure Calculation for the CCA Bond

Subtract the IOU's Stressed Bundled Gen Rate from the Returning CCA Bundled Generation Cost and multiply by the annual CCA load (in MWh) to determine the estimated procurement-related cost exposure.

- Estimated Procurement-related Cost Exposure = (Returning CCA Bundled Generation Cost – IOU's Stressed Bundled Gen Rate)* Annual CCA MWh

9. Incremental Administrative Cost Calculation for the CCA Bond

Estimate the Administrative Costs (time and materials) using the IOU's authorized service fee rate for voluntarily returning CCA accounts times forecasted number of CCA accounts.

- Estimated Administrative Costs = IOU's authorized service fee rate for voluntarily returning CCA customer accounts (for PGE, currently $3.94; for SCE, currently $1.49; and, for SDG&E, currently $1.12)*Forecasted number of CCA accounts

10. Sliding Scale Factors

For Year 1, including the first semi-annual update calculation, of CCA operation, the gross bond amount will reflect 50% of the estimated procurement-related cost exposure plus the administrative fee estimate, but will not be less than the administrative fee estimate.

ffi 1st Year Gross Bond Amount = max [50%* (Returning CCA Bundled Generation Cost – IOU's Stressed Bundled Gen Rate)* Annual CCA MWh + Estimated Admin Costs; Estimated Admin Costs]

For Year 2 the 50% factor will increase to 75%, and for Year 3 onward, 100% of the estimate will be used to calculate the gross bond amount. The gross bond amount for Year 2 and Year 3 onward shall likewise not be less than the administrative fee estimate. Each phase of a CCA Service phase-in will be treated separately for the purpose of applying the sliding-scale factors used above.

11. Offsets to the Gross CCA Bond

Options may be available to CCAs for offsets to the gross bond amount required to be posted under this settlement pursuant to Public Utilities Code Section 394.25(e) and Commission CCA-related decisions. PG&E, SCE, TURN, SJVPA and Victorville have agreed to a separate settlement agreement relating to the offset for CCA Accounts Receivable[2] which will be submitted to the Commission for approval.

12. Posting and Adjustments to CCA Bond Amounts

The posted bond amount shall be the gross bond amount adjusted by any applicable offsets. After the initial bond has been posted, the CCA's gross and posted bond amounts shall be calculated twice a year (unless a new phase of the CCA Service program is implemented, in which case the additional gross and posted bond amounts will also be calculated upon the start of the new phase, as described in Section 1 above) and adjusted if/when it is more than 10% above or below the then-current CCA posted bond amount. Posted bond may be in the form of a surety bond, letter of credit, cash or cash equivalent financial instrument or security, or such other

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[2] The term "CCA Accounts Receivable" as used in this agreement shall have the meaning attributed to it in the separate settlement agreement among PG&E, SCE, TURN, SJVPA, and Victorville relating to the offset for CCA Accounts Receivable.

instrument reasonably acceptable to the IOU and shall be payable to the IOU directly in the event a CCA fails to timely pay the re-entry fees demanded by the IOU as described in Section C.13.

13. Re-entry Fee Calculation

Involuntarily returned CCA customers will be placed on IOU bundled service. Within sixty (60) days of (i) the start of the involuntary return, or (ii) the IOU's receipt of the CCA's written notice of involuntary return, whichever occurs first, the re-entry fees shall be determined as a binding estimate of the incremental administrative costs and the expected cost of power procurement contracts that will have to be added to the IOU's bundled service portfolio under then-current market conditions to serve the CCA customers for a one-year period starting on the date the involuntary return of the CCA customers starts or is expected to start, as applicable (One-Year Period). The binding estimate shall be determined by starting with the MPB based on a one-year forward strip plus RA value and losses, modified as follows:

- o The MPB will be based on the average of daily "ask" forward prices for the One-Year Period collected during the 4-week period after the date the involuntary return of CCA customers starts or the 4-week period after the IOU's receipt of a written notice from the CCA of the involuntary return, whichever is earlier.
- o Include an adjustment to this "baseload" price to account for on-/off-peak prices as applied to the load shape of the CCA. The load shape of the CCA will be the weighted class average based on publicly available information.
    - ffi Average Forward Peak Price = PF ($/MWh)
    - ffi Average Forward Off-Peak Price = OF ($/MWh)
    - ffi Estimated CCA Peak Period usage for 12 forward months = PL (MWh)
    - ffi Estimated CCA Off-Peak Period usage for 12 forward months = OL (MWh)
    - ffi F: Load Shape Adjusted Forward price
    - ffi F = [(PF*PL) + (OF*OL)]/(PL+OL)
- o Loss adjustment at L% (specific to each utility)

- ffi Loss Adjusted Forward is AF = (L%)*F

- o RA cost to be determined as follows:
  - ffi When CAISO "backup capacity" is determined by either ICPM or Supplemental Revenues:
    - ffi Greater of RA cost in Section 1 or the greater of Interim Capacity Procurement Mechanism (ICPM) payments for next year under ICPM designation or maximum of Supplemental Revenues (SR) payments under Exceptional Dispatch over the previous year.
  - ffi When CAISO "backup capacity" is determined by a "new" mechanism that may replace ICPM and/ or Supplemental Revenues:
    - ffi Greater of RA cost in Section 1 or the "new" mechanism used to value CAISO backup capacity for 12 months forward

- o In the event that additional flexible RPS compliance is not confirmed by the CPUC per Section 3 above, calculate the Re-entry RPS premium as follows:
  - ffi Re-entry RPS Premium = Maximum Actual premium for resources procured to meet RPS, during the most recent 3 years, for renewable energy delivery to the IOU over the next 5 years).
  - ffi The Re-entry RPS Premium will be applied to the fraction of returning CCA load at the IOU's then existing RPS annual target of Y% as in Section 4.

- o Average Procurement Cost per MWh for the involuntarily returned CCA load = F+X%*RA Cost + Y%* Re-entry RPS Premium
  - ffi X% is determined (as in Section 6) as follows:
    - ffi The default value of X% is 115% but would be modified to account for the IOU's procurement of capacity for so-called "benefiting" customers per D.06-07-029. The 115% requirement will be reduced by the percentage of capacity procured pursuant to D.06-07-029 relative to the IOU service territory peak load.

- o Compare the resulting average procurement cost to the average cost of power from the applicable CCA-specific bundled service portfolio for this same time period. The CCA-specific bundled service portfolio cost is derived as follows:

ffi CCA Specific Bundled Gen Rate = [System Annual Average Gen Rate for Class A*Annual MWh for Class A + System Annual Average Gen Rate for Class B*Annual MWh for Class B +... for all classes] / [Annual MWh for Class A + Annual MWh for Class B+ … for all classes]

If the average cost of the new power procurement for returning CCA customers is higher, multiply the difference in average procurement costs of the two portfolios (in dollars per MWh) times the annual load of the returning CCA customers to calculate the IOU's incremental procurement costs. The re-entry fees owed by the CCA shall equal an IOU's incremental procurement costs plus the incremental administrative costs associated with the CCA customers' involuntary return, calculated as a binding estimate using the IOU's authorized service fee rate for voluntarily returning CCA accounts times the number of involuntarily returned CCA accounts. The amount calculated as outlined above shall be a binding estimate of the re-entry fees owed by the CCA and shall not be subject to any "true up." The IOU's demand for the re-entry fees shall be made no later than sixty (60) calendar days after the start of the involuntary return of CCA accounts to IOU procurement service, and the re-entry fees shall be due and payable to the IOU within 15 calendar days after the issuance of the demand.

The failure of the CCA to pay the full amount of re-entry fees demanded by the IOU when they are due and payable to the IOU (as provided for above) shall trigger a payment to the IOU under any bond or letter of credit or other financial or security instrument established for the CCA's bond obligation.

To the extent the CCA is unable to fully satisfy its obligation to pay the full amount of the re-entry fees (as calculated above via a binding estimate, not subject to future "true up"), through its bond(s), letter(s) of credit, CCA Accounts Receivable, collateral, cash, insurance or other financial resources, by the date they become due and payable to the IOU, then the IOU will charge the amount of re-entry fees unrecovered as of that date to the group(s) of customers that the Commission determines should bear those fees, either on a one-time basis or over some reasonable period. The Commission's **conclusive determination of which group(s) of customers shall be responsible for any re-entry fees not satisfied by the CCA shall be considered a condition precedent to final approval of this Settlement.** If the IOU subsequently recovers additional re-entry fees from another source, a partial or full refund shall be provided to such customers.

14. Failure to Post the Required Bond Amount

The Parties acknowledge that under certain circumstances a CCA's failure to post the required bond amount may constitute an emergency under Rule 23.T.3 ("Change of Service Election in Exigent Circumstances"), namely, the failure poses a substantial threat of irreparable economic or other harm to the utility or the customer. Nothing herein is intended to affect or alter the process described in Rule 23.T.3 by which the Commission determines whether or not the CCA's failure constitutes an emergency and whether the utility may terminate the CCA's service under Rule 23.T.3. The Parties also acknowledge that the utility may, alternatively, pursue the termination process described under Rule 23.T.4 ("Change of Service Election Absent Exigent Circumstances") to address a CCA's failure to post the required bond amount.

15. Inclusion of Other Costs in the CCA Bond and Re-entry Fee Calculations

The Parties acknowledge that the method for calculating the CCA bond and re-entry fees recommended in this Settlement may require modification to account for incremental costs incurred in an involuntary return of CCA customers for other CPUC-mandated purchases the IOUs have to make in serving their bundled customers, such as costs for greenhouse gases mitigation mandated by AB 32 beginning in 2012. Where practical, the Parties shall pursue good faith efforts to seek forbearance from the Commission of the requirement to incur any such incremental costs on a basis similar to that set forth above under Section 3 relating to RPS costs.

16. Collaboration on Advice Filings Implementing the CCA Bond/Re-entry Fee Settlement Agreement

In the event the CPUC requires an advice letter or other submission for the purpose of modifying IOU tariffs or otherwise implementing the provisions of this Agreement, the Parties agree that they will make good faith, timely efforts to reach agreement on the content of any such advice letter or other submission before it is presented to the CPUC for approval.

17. Data Request for Bond Calculation Inputs

Upon written request of a prospective or operating CCA, an IOU shall provide within 15 business days or sooner if feasible the currently available inputs necessary for the calculation of the bond amount. The bond calculation resulting from these inputs is for illustrative purposes only and is not intended to replace or supersede Sections C.1 through C.10 above. The IOU shall provide these inputs to a prospective or operating CCA upon request up to once per quarter unless otherwise agreed.

18. Exhibits to the CCA Bond/Re-Entry Fee Settlement Agreement

A sample bond calculation for SJVPA's CCA program in PG&E's service area is set forth in **Exhibit 1** of this Agreement. This calculation is illustrative only.

Descriptions of the Stressed Energy Price calculation for the CCA bond are set forth in **Exhibit 2** of this Agreement. The numbers used in Exhibit 2 are illustrative only.

D. <u>Implementation of Agreement</u>

It is the intent of the Settling Parties that the Commission adopt this Agreement in its entirety and without modification.

E. <u>Incorporation of Complete Agreement</u>

This Agreement is to be treated as a complete package and not as a collection of separate agreements on discrete issues. To accommodate the interests related to various issues, the Parties acknowledge that changes, concessions or compromises by a Party or Parties in one section of this Agreement resulted in changes, concessions or compromises by a Party or Parties in other sections. Consequently, the Parties agree to oppose any modification of this Agreement not agreed to by all Parties. Any Settling Party may withdraw from this Settlement Agreement if the Commission modifies it. The Settling Parties agree, however, to negotiate in good faith with regard to any Commission-ordered changes in order to restore the balance of benefits and burdens, and to exercise the right to withdraw only if such negotiations are unsuccessful. The terms and conditions of this Settlement Agreement may only be modified in writing subscribed to by the Settling Parties.

F. <u>Regulatory Approval</u>

The Parties shall use their best efforts to obtain Commission approval of this Agreement. The Parties shall jointly request that the Commission:

a. Suspend the procedural schedule in this proceeding and permit the Parties to brief the Commission on which group(s) of customers should be responsible for any unrecovered re-entry fees to the extent the CCA is unable to fully satisfy its obligation to pay the full amount of the re-entry fees, following the schedule set forth in Rule 12.2 for comments and reply comments on settlements;

b. Adopt this Agreement in its entirety and without modification as reasonable in light of the record, consistent with law, and in the public interest;

c. Confirm that the IOUs as POLRs will be provided additional flexibility beyond the window of flexible compliance to meet the RPS for involuntarily returned CCA load. Specifically, confirm that the IOUs will be provided one additional calendar year beyond the window of flexible compliance after the calendar year in which the CCA load involuntary returns, or four calendar years (using the current three years flexible compliance set by the Commission) after the calendar year in which the IOU received actual notice from the CCA of the involuntary return, whichever comes first, to meet RPS for the involuntarily returned CCA load;

d. Conclusively determine, based on the Settling Parties' comments and reply comments on the Settlement Agreements and the entire record in this proceeding, which group(s) of customers should be responsible for any unrecovered re-entry fees to the extent the CCA is unable to fully satisfy its obligation to pay the full amount of the re-entry fees; and

e. Order the IOUs to file advice letters within 60 days of the issuance of the Commission's decision approving the Settlement Agreements to modify their CCA tariffs in compliance with that decision.

G. Compromise of Disputed Claims

This Agreement represents a compromise of disputed claims between the Parties. The Parties have reached this Agreement after taking into account the possibility that each Party may or may not prevail on any given issue. The Parties assert that this Agreement is reasonable, consistent with law and in the public interest.

H. Non Precedential

Consistent with Rule 12.5 of the Commission's Rules of Practice and Procedure, this Agreement is not precedential in any other proceeding before this Commission, except as provided in this Agreement or unless the Commission expressly provides otherwise.

I. Previous Communications

This Agreement contains the entire agreement and understanding between the Parties as to the subject matter of this Agreement, and supersedes all prior agreements, commitments, representation, and discussions between the Parties. In the event there is any conflict between the terms and scope of the Agreement and the terms and scope of the accompanying joint motion, this Agreement shall govern.

J. Non Waiver

None of the provisions of this Agreement shall be considered waived by any Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of their rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

K. Effect of Subject Headings

Subject headings in this Agreement are inserted for convenience only, and shall not be construed as interpretations of the text.

L. Governing Law

This Agreement shall be interpreted, governed and construed under the laws of the State of California, including Commission decisions, orders and rulings, as if executed and to be performed wholly within the State of California.

M. Number of Originals

This Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

San Joaquin Valley Power Authority
By:____________________________
Title:___________________________
Date:___________________________

City of Victorville
By:____________________________
Title:___________________________
Date:___________________________

The Utility Reform Network

By:______________________________

Title:______________________________

Date:______________________________

Southern California Edison Company

By:______________________________

Title:______________________________

Date:______________________________

San Diego Gas & Electric Company

By:______________________________

Title:______________________________

Date:______________________________

Pacific Gas and Electric Company

By:______________________________

Title:______________________________

Date:______________________________

EXHIBIT 1: Sample Calculation of SJVPA Bond Requirement

Assumptions:

1. This calculation is illustrative and only for the PG&E portion of the SJVPA load.
2. MPB is based on the average of April 2009 market data for July 2009-June 2010 is $41.51 per MWh.
3. The estimate of implied volatility of 42.62% is based on the average of available volatility data in April 2009 for July 2009-June 2010.
4. The average bundled generation rate for PG&E is $93.55 per MWh effective March 1, 2009.
5. SJVPA load for the PG&E territory is assumed to be 1,992,900 MWh and consisting of 200,000 customer accounts.
6. For the offset calculation, a 6 week holdback period and SJVPA average gen rate for its customers in PG&E's service territory is assumed to be $88.87 per MWh, based upon SJVPA's plan to set rates at 5% below PG&E's bundled generation rate ($93.55 [above] * 95%).

Sample Calculation:

ffi Market Price Benchmark = $41.51 per MWh for baseload energy times 1.06 for losses and times 1.00 for load shape adjustment with respect to market flat price = $44.00 per MWh. RA Price in MPB =$4/MWh

ffi Gross up factor for the stress price calculation = 1.5688 as per the TeVaR method

  o Exp(-0.5*V*V*T+V*sqrt(T)*1.64)

    ffi V is the implied volatility of 42.62%

    ffi T is the average time to expiration of 0.5 in years

ffi Stressed Energy Price = $69.03 per MWh

ffi Stressed RA Price = RA Price in MPB*Stress Factor = $6.28 per MWh

ffi Assume RPS Forbearance. Stressed RPS Premium = 0

ffi Returning CCA Bundled Generation Cost = Stressed Energy Price + (1.15)*Stressed RA Price + 0.2*Stressed RPS Premium = $69.03 + 1.15*6.28 = $76.25 per MWh

ffi Calculate the Stressed Bundled Gen Rate. Current Bundled Gen Rate = $93.55 per MWh; assuming the calculated CCA Load Adjustment is 100%, CCA Load Adjusted Bundled Gen

Rate = 100%*$93.55 = $93.55 per MWh plus $10 per MWh = $103.55 per MWh

- Bundled customer exposure = $76.25-$103.55 = - $27.30 per MWh
- Admin fee = $3.94 per account. Assume 200,000 accounts, then admin fee = $788,000
- Holdback in which the IOU has perfected senior security interest
  - Assume 6 weeks at a rate of $88.87 per MWh
    - Translates into 6/52*88.87 = $10.25 per MWh for an annual load
- 1st year bond amount. Assume total SJVPA load is 1,992,900 MWh.
  - Gross Bond amount = Greater of 50%* [-$27.30*1,992,900]+$788,000 or $788,000 = $788,000
  - Offset with holdback security interest = $20,436,231
  - Posted bond amount is zero
- 2nd year bond amount.
  - Gross Bond amount = Greater of 75%* [-$27.30*1,992,900]+$788,000 or $788,000 = $788,000
  - Offset with holdback security interest = $20,436,231
  - Posted bond amount is zero
- 3rd year bond amount.
  - Gross Bond amount = Greater of [-$27.30*1,992,900]+$788,000 or $788,000 = $788,000
  - Offset with holdback interest = $20,436,231
  - Posted bond amount is zero

EXHIBIT 2: "Stressed" Energy Price Calculation

CCA Bond Calculation

Proposed IOU Model

January 15, 2009

CCA Bond Calculation

Energy Price Risk (Joint IOU Model)

- There is an actively traded forward market for energy
- Energy price risk can be calculated by observable data in the market
- Calculation Steps- Get Market Data
  - Determine the forward price of a flat annual strip of energy
    - On-peak and Off-peak energy prices can be obtained from
      - Dealers
      - ICE screens
      - Bloomberg screens
  - Determine the implied volatility of the forward annual strip
    - There is a market for options going out 18 months
      - Dealers can provide indicative quotes on request
        - ICAP/Amerex provide on a “paid subscription” basis published implied volatilities for forward markets

CCA Bond Calculation

Energy Price Risk Contd. (Joint IOU Model)

- Calculate flat strip forward price
  - Average of available flat prices (Example 1 in the attached spreadsheet) or weighted, by number of hours, average peak and off peak prices
- Estimate average annualized volatility
  - Black formula for implied volatility
  - In case several data points are available, a square root of time weighted average is used (Example 1)
- Estimate average time to expiration of CCA procurement
  - Set at 0.5 years

CCA Bond Calculation

Energy Price Risk Contd. (Joint IOU Model)

- By now we have
  - Estimate of the current forward price: CF
  - Estimate of the volatility: V
  - Estimate of average time to expiration: T
  - Confidence interval of 95%

- Now we use the standard integral of a normal distribution of price changes to the average time to expiration and the specified confidence interval to calculate the stressed average price of energy
  - CF*Exp[(-0.5*V*V*T)+(V*sqrt(T)*1.64)]

- The resulting price is the 95% confidence flat energy stressed price

DRAFT - For Discussion Only

Workbook Purpose:	**Objective 1:** To provide a template for the calculation of the CPUC mandated Consumer Choice Aggregation (CCA) Bond posted to the utilities in any given period for the protection of bundled customers in the case of involuntary return
Version:	2009-05-04.XX
Owners:	Joint IOU Model

Sheets:	Workbook Notes	Provides intent of this workbook.
	BlacksModelDirections	
	Definitions	
	BondCalculation	
	CCA Bond Summary	
	US DOE Green Power Estimates	

BLACK'S MODEL

Purpose

This workbook generates the 95% confidence interval risk price scenario for an annual power strip

The aim is to estimate how much the price would increase from the forward curve using TeVaR-like methodology except by using closed form formulae rather than a simulation

The distribution that results is a log normal distribution as oppoosed to a normal distribution

Formula

1 Estimated strip price increase: Cell E65 in the "Bond Calculation" tab

Forward Price * [EXP (-0.5* Volatility ^2 * Time + Confidence Interval * Volatility * Square root of Time)

2

The Time in the calculation is the square of the mean of square roots of each underlying product's time to expiration

Sources of data

1 Independent brokers of NP15 and SP15 forward and option prices and implied volatiltie s

2 Independent brokers available to the public would be the likely sources of forward data

3 Implied volatility for bond calculation period equals the implied volatility for Flat Price supplied by independent broker quotes

4 The time to expiration weighted average of derived implied variance is used as the estimate of implied variance for the annual flat strip

Terms and comments

1 EXP - base of the natural log or 2.7138 - this factor is used to derive the log normal distribution

2

Networkdays - number of trading days from the valuation date to first day of the month prior to the delivery month/260 trading days. For example the number of days from 5/30 through June 30 is 21 days. 21/260 equals = .08.

3 (-0.5*Volatility^2*time) - this part of the equation provides for the relative small component of the change in forward prices

4 (Confidence Interval*Volatility*Sqrt of Time) - this part of the equation provides for the largest component of the change in the forward price at a specified confidence interval

5 The same methodology will apply when data for different strips/months is available

Definitions

	Item	Value	Definition/Description
1	Trade Date	4/30/2009	The last day of Month M-1 used to average the forward price. The adjusted Forward price will be based on the average of a the trade days of Month M-1.
2	Confidence Interval	95%	CPUC designated Risk Threshold for IOU's for all "Worst Case Scenario" calculations
3	Interest Rate	1%	Risk free interest rate used in Black's model. Defined as the current interest rate of
4	Network Trading Days	260	Networkdays - number of trading days from the valuation date to first day of the month prior to the delivery month/260 trading days. For example the number of days from 5/30 through June 30 is 21 days. 21/260 equals = .08.
5	Adjusted Forward Price (Market Price Benchmark)	$44.00	The average of Peak/Off Peak Prices for all the trading days in month M-1
6	RA Price reported in MPB Calculation	$4.00	The average cost of capacity (in MWh) for Resource Adequacy compliance
7	RA Capacity for Compliance Factor	115%	CPUC designated capacity purchase requirement for peak load over the year. This percentage is subject to change with CCA allocation of CAM
8	Annual RPS Requirement	20%	IOU/CCA request for RPS Forebearance. If forebearance is denied, the Annual RPS requirement is subject to change with CPUC mandates
9	RPS Premium Cost	$0.00	Taken from the Department of Energy Website. The RPS Premium cost is the 95%tile of all published RPS premiums in the United States (See US DOE Green Power Estimates)
10	IOU System Average Bundled Rate	$93.55	The overall average bundled generation rate of all IOU customers. Derived from each IOU's ERRA Calculation on an annual basis.
11	$10/MWH Stressed Generation Price Adder	$10.00	Negotiated Risk Price Offset for CCA customers, set to $10. (Non-changing)
12	Average Peak Price in M-1 month for months M+2 to M+13 inclusive	47.4629	Average On Peak (6x16) system price published by broker quotes
13	Average Off-Peak Price in M-1 month for months M+2 to M+13 inclusive	33.5673	Average Off Peak system price published by broker quotes
14	Number of Peak Hours for months M+2 to M+13 inclusive	5008	Total number of Peak hours for the bond calculation period. Ie: hours from 7 to 22
15	Number of Off Peak Hours for months M+2 to M+13 inclusive	3752	Total number of Off Peak hours for the bond calculation period. Ie: hours from 1 to 6 and 23 to 24
16	Losses Factor Specific to IOU	106%	The percentage, IOU specific, of average power lost over transmission lines
17	Load Adjustment?	N/A	Inclusion of the Load adjustment pending. If the CPUC decides to include a load adjustment to the CRS calculation, a CCA specific load adjustment factor will be included in this calculation
18	Load Factor/Shape	100%	Until a CCA specific load adjustment is in place, Load Factor will be negligible.
19	Average Flat Price in M-1 month for months M+2 to M+13 inclusive	$41.51	Adj. Forward Price =((Off Peak Price* Off Peak Load) + (Peak Price*Peak Load))/(Off Peak Load + Peak Load)*(loss factor*load shape factor)
20	Adjusted Forward Price (Market Price Benchmark)	$44.00	The final price used to calculate IOU Risk exposure. Ie: The Average Flat Price in M-1 for Months M+2 to M+13 inclusive including Losses, RA Price, and any Load Factor
21	Derived Average Volatility	43%	Calculated using Black's Model: The Square Root of the Sum of "Time to Expiration" for all Months and "Sigma Squared" for all Months M+2 to M+13 inclusive
23	Confidence Interval Multiplier	1.6449	
24	Stressed Energy Price @ 95% Confidence	$69.03	The "Worst Case Scenario" Cost of Energy potentially faced by an IOU in the case of an involuntarily returned CCA
25	Sress Factor	1.5688	The ratio of Stressed Energy Price to adjusted Forward Price. This ratio numerates the increase in Energy price, that same factor is applied to the RA price
26	Stress RA Price	$6.28	The Risk RA Price, calculated by applying the gross up factor to the Market RA Price
27	Involuntarily Returned CCA Bundled Generation Cost	$76.25	Generation Rate for CCA Customers in a stress market.
28	Bundled Customer Exposure	-$27.30	The incremental cost above the current system bundled generation rate the IOU is at risk for

4A-31

SB_GT&S_0015374

	A	B
1	**Bond Calculation Template**	
2		**Updated Monthly: Insert Data here**
3		**Subject to change according to CPUC decisions/IOU or CCA Updates**
4	Last Data Date	4/30/2009
5	IOU	PG&E
6	Confidence Interval	95%
7	Interest Rate	1%
8	Network Trading Days	261
9	Number of Sundays	52
10	Adjusted Forward Price (Market Price Benchmark)	**$ 44.0**
11	RA Price reported in MPB Calculation	**$ 4.0**
12	RA Capacity for Compliance Factor	**115%**
13	RPS Forbearance?	**Yes**
14	Annual RPS Requirement	**20%**
15	RPS Premium Cost	**$0.00**
16	IOU System Average Bundled Rate	**$ 93.55**
17	Stressed Generation Rate Adder ($ per MWh)	**$ 10.0**
18		
19	**Market Price Benchmark Calculation**	
20		
21	Average Peak Price in M-1 month for months M+2 to M+13 inclusive	**$ 47.5**
22	Average Off-Peak Price in M-1 month for months M+2 to M+13 inclusive	**$ 33.6**
23	Number of Peak Hours for months M+2 to M+13 inclusive	5008
24	Number of Off Peak Hours for months M+2 to M+13 inclusive	3752
25	Losses Factor Specific to IOU	**106%**
26	Load Adjustment?	**No**
27	Load Factor/Shape	**100%**
28	Average Flat Price in M-1 month for months M+2 to M+13 inclusive	$41.51
29	Adjusted Forward Price (Market Price Benchmark)	$44.00
30		
31		
32		

=(NETWORKDAYS($B$42, $C$53))

=$B$29

If RPS Forbearance granted, an RPS premium cost will not be included in the bond calculation and RPS Premium Cost set to $0.

=IF(B13="yes", 0,'US DOE Green Power Estimates'!$E$5)

=AVERAGE(I42:I53)

=AVERAGE(J42:J53)

=($C$53-$B$42+1-$B$9)*16

=($C$53-$B$42+1)*24-$B$23

Load Shape Adjustment: Please select "Yes" if Load Shape Adjustment has been implemented

=(($B$21*B23)+($B$22*$B$24))/($B$23+$B$24)

=$B$28*$B$25*$B$27

	A	B	C	D	E	F	G	H	I	J
33										
34										
35										
36										
37										
38	**Average Volatility Calculation:**									
39		Beginning Date	Ending Date	Expiry Date	Time to Expiration	Volatility	Sigma^2*T	square root of time	On-Peak Annual Forward	Off-Peak Annual Forward
40	Month M+2	7/1/2009	7/31/2009	6/30/2009	0.1686	**66%**	0.0734	0.5067	$45.44	$28.63
41	Month M+3	8/1/2009	8/31/2009	7/31/2009	0.2567	**64%**	0.1051	0.5807	$43.77	$29.19
42	Month M+4	9/1/2009	9/30/2009	8/31/2009	0.3372	**62%**	0.1296	0.6492	$43.77	$29.19
43	Month M+5	10/1/2009	10/31/2009	9/30/2009	0.4215	**53%**	0.1184	0.7112	$45.77	$33.81
44	Month M+6	11/1/2009	11/30/2009	10/31/2009	0.5057	**50%**	0.1264	0.7656	$45.77	$33.81
45	Month M+7	12/1/2009	12/31/2009	11/30/2009	0.5862	**51%**	0.1525	0.8212	$45.77	$33.81
46	Month M+8	1/1/2010	1/31/2010	12/31/2010	1.6743	**39%**	0.2547	0.8688	$51.13	$38.12
47	Month M+9	2/1/2010	2/28/2010	1/31/2010	0.7548	**38%**	0.1090	0.9118	$51.13	$38.12
48	Month M+10	3/1/2010	3/31/2010	2/28/2010	0.8314	**37%**	0.1138	0.9589	$51.13	$38.12
49	Month M+11	4/1/2010	4/30/2010	3/31/2010	0.9195	**35%**	0.1126	1.0019	$48.62	$33.33
50	Month M+12	5/1/2010	5/31/2010	4/30/2010	1.0038	**34%**	0.1160	1.0413	$48.62	$33.33
51	Month M+13	6/1/2010	6/30/2010	5/31/2010	1.0843	**36%**	0.1405	1.0810	$48.62	$33.33
52										
53										
54	*Derived Average Volatility*				**42.62%**					
55										
56	*Negotiated Average time to expiration*				**0.5**					
57										
58	*Confidence Interval Multiplier*				1.6449					
59										
60	*Stressed Energy Price @ 95% Confidence*				**$ 69.03**					
61	*Stress Factor*				1.5688					
62	*Stressed RA Price*				$6.28					
63	*Involuntarily Returned CCA Bundled Generation Cost*				**$ 76.25**					
64	*Bundled Customer Exposure*				**$ (27.30)**					
71										
72										
73										
74										

=NETWORKDAYS($B$4,D42)/$B$8

=F42^2*E42

=SQRT(NETWORKDAYS($B$4,C42)/$B$8)

=SQRT(SUM($G$42:$G$53)/SUM($E$42:$E$53))

=NORMSINV($B$6)

=$B$10*EXP(-0.5*$E$56^2*$E$58+$E$56*SQRT($E$58)*$E$60)

=$E$62/$B$10

=$E$63*$B$11

=$E$62+($B$12*$E$64)+($B$14*$B$15)

=$E$65-($B$16+$B$17)

	A	B	C	D	E	F	G	H	I
1	**Bond Calculation:**								
2									
3	**# ofMetered Accounts**	200,000	Provided by CCA						
4	**CCA Load**	350	MW						
5	**CCA Load Factor**	0.65	Provided by CCA Implementation Plan						
6	**Administrative Fee per metered account**	$3.94	Per IOU tariffs						
7	**Year of CCA Operation**	1							
8	**Year 1 Fraction**	50%							
9	**Year 2 Fraction**	75%							
10	**# of Days per Year**	365							
11	**# of Hours per Day**	24							
12									
13									
14	**CCA NAME**	**CCA Bond Fraction**	**Total Bundled Customer Exposure**	**RPS Cost**	**Administrative fee**	**Gross Bond Amount $**	**Gross Bond $/MWh**		
15	**SJV CCA**	50%	$0	$0	$788,000	$788,000	$0.40		
16									
17									
18									
19									

=BondCalculation!$B$14*BondCalculation!B15*B5*B4*365*24

=MAX($E$15,SUM(C15:E15))

=1-IF($B$7=1,$B$8,IF($B$7=2,$B$9,1))

=MAX(0,B15*$B$5*$B$4*$B$10*$B$11*BondCalculation!$E$66)

=$B$6*$B$3

=F15/(B10*B11*B4*B5)

4A-34

SB_GT&S_0015377

	A	B	C	D	E	F	G	H	I	J
1	**DOE Renewable Energy Premium Payments (Copy/Paste from Site)**									
2								=PERCENTILE(G9:G202,0.95)		
3			95 %'tile	4.18	¢/kWh		Average Premium (Cents/kWh)			
4			95th - EV	2.15	¢/kWh		$2.02			
5				2,150.74	¢/MWh					
6			=D5/100	$21.51	$ per MWh	=D4*1000		=D3-G4		
7										
8	State	Utility Name	Program Name	Type	Start Date	Premium				
9	CO	Xcel Energy	WindSource	wind	1997	-0.67¢/kWh	-0.67¢/kWh			
10	OK	OG&E Electric Services	OG&E Wind Power	wind	2003	-	-0.25¢/kWh			
11	TX	Bandera Electric Cooperative	Choose-To-Renew	wind, hydro	2005	-	-0.11¢/kWh			
12	CO	Platte River Power Authority: Estes Park, Fort Collins Utilities, Longmont Power & Communications, Loveland Water & Power	Wind Energy Premium	wind	1999	1.0¢/kWh-2.5¢/kWh	1.75¢/kWh			
13	DE	Delaware Electric Cooperative	Renewable Energy Rider	landfill gas	2006	0.2¢/kWh	0.20¢/kWh			
14	ID	Avista Utilities	Buck-A-Block	wind	2002	0.33¢/kWh	0.33¢/kWh			
15	WA	Avista Utilities	Buck-A-Block	wind	2002	0.33¢/kWh	0.33¢/kWh			
16	CO	Colorado Springs Utilities	Renewable Energy Certificates Program	wind and geothermal	2008	0.34¢/kWh	0.34¢/kWh			
17	IN	Indianapolis Power & Light	Green Power Option	wind	1998	0.35¢/kWh	0.35¢/kWh			
18	IA	Basin Electric Power Cooperative: Lyon Rural, Harrison County, Nishnabotna Valley Cooperative, Northwest Rural Electric Cooperative, Western Iowa	Prairie Winds	wind	2000	0.5¢/kWh	0.50¢/kWh			
19	MN	Basin Electric Power Cooperative: Minnesota Valley Electric Coop, Sioux Valley Southwestern	Prairie Winds	wind	2002	0.5¢/kWh	0.50¢/kWh			
20	MN	Minnkota Power Cooperative: Beltrami, Clearwater Polk, North Star, PKM, Red Lake, Red River, Roseau, Wild Rice; Northern Municipal Power Agency (10 municipals)	Infinity Wind Energy	wind	1999	0.5¢/kWh	0.50¢/kWh			
21	MT	Basin Electric Power Cooperative: Flathead Electric Coop, Lower Yellowstone, Powder River Energy	Prairie Winds	wind	2000	0.5¢/kWh	0.50¢/kWh			
22	ND	Basin Electric Power Cooperative: Burke Divide, Capital, Dakota Valley, KEM Electric Coop, Oliver Mercer Electric Coop, McKenzie Electric Coop, Montrail Williams, Mor-gran-sou Electric Coop, North Central Electric Coop, Northern Plains, Slope Electric Coo	PrairieWinds	wind	2000	0.5¢/kWh	0.50¢/kWh			
23	ND	Minnkota Power Cooperative: Cass County Electric, Cavalier Rural Electric, Nodak Electric; Northern Municipal Power Agency (2 municipals)	Infinity Wind Energy	wind	1999	0.5¢/kWh	0.50¢/kWh			
24	OH	FirstEnergy: Ohio Edison Company	Green Resource Program	various	2007	0.5¢/kWh	0.50¢/kWh			
25	OH	FirstEnergy: The Cleveland Electric Illuminating Company	Green Resource Program	various	2007	0.5¢/kWh	0.50¢/kWh			
26	OH	FirstEnergy: The Toledo Edison	Green Resource Program	various	2007	0.5¢/kWh	0.50¢/kWh			
27	OK	Western Farmers Electric Cooperative (19 of 19 coops offer program): Alfalfa Electric Cooperative, Caddo Electric Cooperative, Canadian Valley Electric Cooperative, Choctaw Electri Cooperative, Cimmaron Electric Cooperative, Cotton Electric Cooperative, E	WindWorks	wind	2004	0.5¢/kWh	0.50¢/kWh			
28	SD	Basin Electric Power Cooperative: Bon Homme-Yankton Electric Assn., Central Electric Cooperative Association, Charles Mix Electric Association, City of Elk Point, Clay-Union Electric Corporation, Codington-Clark Electric Cooperative, Dakota Energy Coopera	Prairie Winds	wind	2000	0.5¢/kWh	0.50¢/kWh			
29	TX	Pedernales Electric Cooperative	Renewable Power	wind, hydro	2006	0.5¢/kWh	0.50¢/kWh			
30	WY	Basin Electric Power Cooperative: Powder River Energy	Prairie Winds	wind	2000	0.5¢/kWh	0.50¢/kWh			
31	CO	Yampa Valley Electric Association	Wind Energy Program	wind	1999	0.6¢/kWh	0.60¢/kWh			
32	WY	Yampa Valley Electric Association	Wind Energy Program	wind	1999	0.6¢/kWh	0.60¢/kWh			
33	OK	Oklahoma Municipal Power Authority: Tonkawa, Altus, Frederick, Okeene, Prague Municipal Utilities and Edmond Electric	Pure & Simple	wind	2004	1.8¢/kWh (-0.45¢/kWh	0.68¢/kWh			
34	WA	Clallam County PUD	Clallam County PUD Green Power Program	landfill gas	2001	0.69¢/kWh	0.69¢/kWh			
35	OH	AEP Ohio	Green Pricing Option	landfill gas	2007	0.7¢/kWh	0.70¢/kWh			
36	WV	AEP Ohio	Green Pricing Option	landfill gas	2007	0.7¢/kWh	0.70¢/kWh			
37	OR	PacifiCorp: Pacific Power / 3Degrees	Blue Sky Usage	wind, biomass, PV	2002	0.78¢/kWh	0.78¢/kWh			
38	AZ	Tri-State Generation & Transmission: Columbus Electric Cooperative, Inc.	Renewable Resource Power Service	wind, hydro	2001	0.8¢/kWh	0.80¢/kWh			
39	CO	Tri-State Generation & Transmission : Delta-Montrose Electric Association, Empire Electric Association, Inc., Gunnison County Electric Association, Inc., Highline Electric Association, La Plata Electric Association, Inc., Morgan County Rural Electric Asso	Renewable Resource Power Service	wind, hydro	1998	0.8¢/kWh	0.80¢/kWh			
40	MT	Tri-State Generation & Transmission: Big Horn Rural Electric Company	Renewable Resource Power Service	wind, hydro	2001	0.8¢/kWh	0.80¢/kWh			
41	NE	Tri-State Generation & Transmission: Chimney Rock Public Power District, Highline Electric Association, Northwest Rural Public Power District	Renewable Resource Power Service	wind, hydro	2001	0.8¢/kWh	0.80¢/kWh			
42	NM	Tri-State Generation & Transmission: Central New Mexico Electric Cooperative, Inc., Columbus Electric Cooperative, Inc., Continental Divide Electric Cooperative, Inc., Jemez Mountains Electric Cooperative, Inc., Kit Carson Electric Cooperative, Inc., Nort	Renewable Resource Power Service	wind, hydro	2001	0.8¢/kWh	0.80¢/kWh			
43	OR	Portland General Electric Company / Green Mountain Energy	Green Source	existing geothermal, hydro, new wind	2002	0.8¢/kWh	0.80¢/kWh			

	A	B	C	D	E	F	G	H	I	J
8	State	Utility Name	Program Name	Type	Start Date	Premium				
44	SD	Tri-State Generation & Transmission: Niobrara Electric Association, Inc.	Renewable Resource Power Service	wind, hydro	2001	0.8¢/kWh	0.80¢/kWh			
45	UT	Tri-State Generation & Transmission: Empire Electric Association, Inc.	Renewable Resource Power Service	wind, hydro	2001	0.8¢/kWh	0.80¢/kWh			
46	WY	Tri-State Generation & Transmission: Carbon Power & Light, Inc.	Renewable Resource Power Service	wind, hydro	2001	0.8¢/kWh	0.80¢/kWh			
47	OR	Eugene Water & Electric Board	EWEB Wind Power	wind	1999	0.91¢/kWh	0.91¢/kWh			
48	IN	Wabash Valley Power Association (7 of 27 coops offer program): Boone REMC, Hendricks Power Cooperative, Kankakee Valley REMC, Miami-Cass REMC, Tipmont REMC, White County REMC, Northeastern REMC	EnviroWatts	landfill gas	2000	0.9¢/kWh-1.0¢/kWh	0.95¢/kWh			
49	ID	Idaho Power	Green Power Program	various	2001	0.98¢/kWh	0.98¢/kWh			
50	OR	Idaho Power	Green Power Program	various	2001	0.98¢/kWh	0.98¢/kWh			
51	AZ	Arizona Public Service	Green Choice	wind and geothermal	2007	1.0¢/kWh	1.00¢/kWh			
52	CA	Sacramento Municipal Utility District	Greenergy	wind, landfill gas, hydro, PV	1997	1.0¢/kWh or $6/month	1.00¢/kWh			
53	CO	Intermountain Rural Electric Association / Sterling Planet	National Wind	wind	2006	1.0¢/kWh	1.00¢/kWh			
54	MN	Southern Minnesota Municipal Power Agency (all 18 munis offer program): Fairmont Public Utilities, Wells Public Utilities, Austin Utilities, Preston Public Utilities, Spring Valley Utilities, Blooming Prairie Public Utilities, Rochester Public Utilities,	SMMPA Wind Power	wind	2000	1.0¢/kWh	1.00¢/kWh			
55	OH	Dayton Power & Light	Green Connect	various	2008	1.0¢/kWh	1.00¢/kWh			
56	OR	Springfield Utility Board	ECOchoice	various	2007	1.0¢/kWh	1.00¢/kWh			
57	WA	Mason County PUD No. 3	Mason Evergreen Power	wind	2003	1.0¢/kWh	1.00¢/kWh			
58	WI	Madison Gas & Electric	Green Power Tomorrow	wind	1999	1.0¢/kWh	1.00¢/kWh			
59	WI	Wisconsin Public Power Inc. (34 of 37 munis offer program): Algoma, Cedarburg, Florence, Kaukauna, Muscoda, Stoughton, Reedsburg, Oconomowoc, Waterloo, Whitehall, Columbus, Hartford, Lake Mills, New Holstein, Richland Center, Boscobel, Cuba City, Hustisfo	Renewable Energy Program	small hydro, wind, biogas	2001	1.0¢/kWh	1.00¢/kWh			
60	MT	Park Electric Cooperative	Green Power Program	various renewables	2002	1.02¢/kWh	1.02¢/kWh			
61	MT	Southern Montana Electric Generation and Transmission Cooperative (5 coops offer program): Fergus Electric, Yellowstone Valley, Bear Tooth Electric, Mid Yellowstone, and Tongue River	Environmentally Preferred Power	wind, hydro	2002	1.05¢/kWh	1.05¢/kWh			
62	WA	Pacific County PUD	Green Power	landfill gas	2002	1.05¢/kWh	1.05¢/kWh			
63	ID	Vigilante Electric Cooperative	Alternative Renewable Energy Program	wind	2003	1.1¢/kWh	1.10¢/kWh			
64	MT	Vigilante Electric Cooperative	Alternative Renewable Energy Program	wind	2003	1.1¢/kWh	1.10¢/kWh			
65	MA	NSTAR	NSTAR Green	wind	2008	0.8¢/kWh-1.45¢/kWh	1.13¢/kWh			
66	WY	Lower Valley Energy	Green Power	wind	2003	1.167¢/kW	1.17¢/kWh			
67	OR	Emerald People's Utility District/Green Mountain Energy	Choose Renewable Electricity	wind, geothermal	2003	1.2¢/kWh	1.20¢/kWh			
68	WA	Tacoma Power	EverGreen Options	wind	2000	1.2¢/kWh	1.20¢/kWh			
69	OR	Eugene Water & Electric Board	EWEB Greenpower	various renewables	2007	1.0¢/kWh-1.5¢/kWh	1.25¢/kWh			
70	WA	Puget Sound Energy	Green Power Program	wind, PV, biogas	2002	1.25¢/kWh	1.25¢/kWh			
71	ID	PacifiCorp: Rocky Mountain Power	Blue Sky	wind	2003	0.71¢/kWh-1.94¢/kWh	1.33¢/kWh			
72	UT	PacifiCorp: Rocky Mountain Power	Blue Sky	wind	2003	0.71¢/kWh-1.94¢/kWh	1.33¢/kWh			
73	WI	We Energies	Energy for Tomorrow	landfill gas, PV, hydro, wind	1996	1.37¢/kWh	1.37¢/kWh			
74	OH	American Municipal Power-Ohio / Green Mountain Energy: City of Bowling Green, Cuyahoga Falls, Westerville, Wyandotte, Yellow Springs	Nature's Energy	small hydro, landfill gas, wind	2003	1.3¢/kWh-1.5¢/kWh	1.40¢/kWh			
75	KY	E.ON U.S.: Louisville Gas and Electric Co., Kentucky Utilities Co.	Green Energy	100% KY Low Impact Hydro Institute-Certified	2007	1.3¢/kWh-1.67¢/kWh	1.49¢/kWh			
76	CA	Anaheim Public Utilities	Green Power for the Grid	wind, landfill gas	2002	1.5¢/kWh	1.50¢/kWh			
77	CA	Palo Alto Utilities / 3Degrees	Palo Alto Green	wind, PV	2003 / 2000	1.5¢/kWh	1.50¢/kWh			
78	CA	Roseville Electric / 3Degrees	Green Roseville	wind, PV	2005	1.5¢/kWh	1.50¢/kWh			
79	CA	Silicon Valley Power / 3Degrees	Santa Clara Green Power	wind, PV	2004	1.5¢/kWh	1.50¢/kWh			
80	CO	Holy Cross Energy	Wind Power Pioneers	wind	1998	1.5¢/kWh	1.50¢/kWh			
81	IL	Dairyland Power Cooperative: Jo-Carroll Energy/Elizabeth	Evergreen Renewable Energy Program	landfill gas, biogas, hydro, wind	1997	1.5¢/kWh	1.50¢/kWh			
82	IA	Corn Belt Power Cooperatives (5 of 11 coops offer program): Butler County REC, Franklin REC, Grundy County REC, Humboldt County REC, Sac County REC	Energy Wise Renewables	wind	2003	1.5¢/kWh	1.50¢/kWh			
83	MN	Dairyland Power Cooperative: Freeborn-Mower Cooperative / Albert Lea, People's / Rochester, Tri-County / Rushford	Evergreen Renewable Energy Program	hydro, wind, landfill gas, biogas	1998	1.5¢/kWh	1.50¢/kWh			
84	MN	Moorhead Public Service	Capture the Wind	wind	1998	1.5¢/kWh	1.50¢/kWh			
85	MO	AmerenUE / 3Degrees	Pure Power	75% wind, 25% other renewables	2007	1.5¢/kWh	1.50¢/kWh			
86	OR	Columbia River PUD	Choice Energy	wind	2005	1.5¢/kWh	1.50¢/kWh			
87	OR	Oregon Trail Electric Cooperative	Green Power	wind	2002	1.5¢/kWh	1.50¢/kWh			
88	OR	Portland General Electric Company / Green Mountain Energy	Renewable Future	wind	2007	1.5¢/kWh	1.50¢/kWh			
89	VA	AEP Appalachian Power	Green Pricing Option	low impact hydro	2008	1.5¢/kWh	1.50¢/kWh			
90	WA	Clark Public Utilities	Green Lights	PV, wind	2002	1.5¢/kWh	1.50¢/kWh			
91	WA	Seattle City Light	Green Up	wind	2005	1.5¢/kWh	1.50¢/kWh			

	A	B	C	D	E	F	G	H	I	J
8	State	Utility Name	Program Name	Type	Start Date	Premium				
92	WI	Dairyland Power Cooperative: Barron Electric, Bayfield/ Iron River, Chippewa / Cornell Valley, Clark / Greenwood, Dunn / Menomonie, Eau Claire / Fall Creek, Jackson / Black River Falls, Jump River / Ladysmith, Oakdale, Pierce-Pepin / Ellsworth, Polk-Burne	Evergreen Renewable Energy Program	hydro, wind, landfill gas, biogas	1998	1.5¢/kWh	1.50¢/kWh			
93	FL	City of Tallahassee/Sterling Planet	Green for You	biomass, PV	2002	1.6¢/kWh	1.60¢/kWh			
94	FL	Keys Energy Services / Sterling Planet	GO GREEN: USA Green	wind, biomass,PV	2004	1.60¢/kWh	1.60¢/kWh			
95	MN	Otter Tail Power Company	TailWinds	wind	2002	1.6¢/kWh	1.60¢/kWh			
96	OR	PacifiCorp: Pacific Power / 3Degrees	Blue Sky Habitat	wind, biomass, PV	2002	0.78¢/kWh + $2.50/mo.	1.64¢/kWh			
97	MI	Consumers Energy	Green Generation	68% wind, 32% landfill gas	2005	1.67¢/kWh	1.67¢/kWh			
98	OR	Portland General Electric Company	Clean Wind for Medium to Large Commercial & Industrial Accounts	wind	2003	1.7¢/kWh	1.70¢/kWh			
99	WI	Great River Energy: Head of the Lakes	Wellspring Renewable Wind Energy Program	wind	1997	1.45¢/kWh-2.0¢/kWh	1.73¢/kWh			
100	OR	Portland General Electric Company	Clean Wind Power	wind	2002	1.75¢/kWh	1.75¢/kWh			
101	MN	Great River Energy (all 28 coops offer program): Agralite, Arrowhead, BENCO Electric, Brown County Rural Electric, Connexus Energy, Co-op Light & Power, Crow Wing Power, Dakota Electric Association, East Central Electric Association, Federated Rural Elect	Wellspring Renewable Wind Energy Program	wind	1998	1.55¢/kWh-2.0¢/kWh	1.78¢/kWh			
102	NM	Los Alamos Department of Public Utilities	Green Power	wind	2005	1.8¢/kWh	1.80¢/kWh			
103	NM	Public Service of New Mexico	PNM Sky Blue	wind	2003	1.8¢/kWh	1.80¢/kWh			
104	TX	Austin Energy (City of Austin)	GreenChoice	wind, landfill gas	2000/1997	1.85¢/kWh	1.85¢/kWh			
105	WI	Wisconsin Public Service	NatureWise	wind, landfill gas, biogas	2002	1.86¢/kWh	1.86¢/kWh			
106	OR	Pacific Northwest Generating Cooperative: Blachly-Lane Electric Cooperative, Central Electric Cooperative, Clearwater Power, Consumers Power, Coos-Curry Electric Cooperative, Douglas Electric Cooperative, Fall River Rural Electric Cooperative, Lost River	Green Power	landfill gas	1998	1.8¢/kWh-2.0¢/kWh	1.90¢/kWh			
107	TX	El Paso Electric Company	Renewable Energy Tariff	wind	2001	1.92¢/kWh	1.92¢/kWh			
108	CA	PacifiCorp: Pacific Power	Blue Sky Block	wind	2000	1.95¢/kWh	1.95¢/kWh			
109	NV	Deseret Power: Mt. Wheeler Power Cooperative	GreenWay	various	2005	1.95¢/kWh	1.95¢/kWh			
110	OR	PacifiCorp: Pacific Power	Blue Sky Block	wind	2000	1.95¢/kWh	1.95¢/kWh			
111	UT	Deseret Power	GreenWay	various	2004	1.95¢/kWh	1.95¢/kWh			
112	UT	PacifiCorp: Utah Power	Blue Sky	wind	2000	1.95¢/kWh	1.95¢/kWh			
113	WA	Pacificorp: Pacific Power	Blue Sky Block	wind	2000	1.95¢/kWh	1.95¢/kWh			
114	WY	Pacificorp: Pacific Power	Blue Sky	wind	2000	1.95¢/kWh	1.95¢/kWh			
115	AL	Alabama Electric Cooperative: City of Andalusia, Baldwin Electric Membership Cooperative, City of Brundidge, Central Alabama Electric Cooperative, Clarke-Washington Electric Membership Cooperative, Coosa Valley Electric Cooperative, Covington Electric Coo	Green Power Choice	landfill gas	2006	2.0¢/kWh	2.00¢/kWh			
116	CA	Burbank Water and Power	Green Energy Champion	various	2007	2.0¢/kWh	2.00¢/kWh			
117	CA	Truckee Donner PUD	Voluntary Renewable Energy Certificates Program	wind	2008	2.0¢/kWh	2.00¢/kWh			
118	FL	Alabama Electric Cooperative: CHELCO, Escambia River Electric Cooperative, Gulf Coast Electric Cooperative, West Florida Electric Cooperative	Green Power Choice	landfill gas	2006	2.0¢/kWh	2.00¢/kWh			
119	FL	Gainesville Regional Utilities	GRUgreen Energy	landfill gas, wind, PV	2003	2.0¢/kWh	2.00¢/kWh			
120	IA	Alliant Energy	Second Nature	landfill gas, wind	2001	2.0¢/kWh	2.00¢/kWh			
121	IA	Central Iowa Power Cooperatives (all 12 coops/1 muni): Maquoketa Valley Electric Cooperative, Eastern Iowa REC, East-Central Iowa REC, Linn County REC, Pella, TIP Rural Electric Cooperative, Clarke Electric Cooperative, Midland Power Cooperative, Guthrie	Wind Power	wind	2006	1.5¢/kWh-2.5¢/kWh	2.00¢/kWh			
122	IA	Waverly Light & Power	Iowa Energy Tags	wind	2001	2.0¢/kWh	2.00¢/kWh			
123	MI	Traverse City Light and Power	Green Rate	wind	1996	2.0¢/kWh	2.00¢/kWh			
124	MN	Alliant Energy	Second Nature	landfill gas, wind	2002	2.0¢/kWh	2.00¢/kWh			
125	MN	Central Minnesota Municipal Power Agency: Blue Earth, Delano, Glencoe, Granite Falls, Janesville, Kenyon, Lake Crystal, Madelia, Mt. Lake, New Ulm, Sleepy Eye, Springfield, Truman, and Windom	Green Energy Program	wind, landfill gas	2000	1.5¢/kWh-2.5¢/kWh	2.00¢/kWh			
126	MN	Xcel Energy	WindSource	wind	2003	2.0¢/kWh	2.00¢/kWh			
127	MT	Northwestern Energy	E+ Green	wind, PV	2003	2.0¢/kWh	2.00¢/kWh			
128	OH	Buckeye Power	EnviroWatts	landfill gas	2006	2.0¢/kWh	2.00¢/kWh			
129	OR	City of Ashland / Bonneville Environmental Foundation	Renewable Pioneers	PV, wind	2003	2.0¢/kWh	2.00¢/kWh			
130	WA	Cowlitz PUD	Renewable Resource Energy	wind, PV	2002	2.0¢/kWh	2.00¢/kWh			
131	WA	Grant County PUD	Alternative Energy Resources Program	wind	2002	2.0¢/kWh	2.00¢/kWh			
132	WA	Lewis County PUD	Green Power Energy Rate	wind	2003	2.0¢/kWh	2.00¢/kWh			
133	WA	Peninsula Light	Green by Choice	wind, hydro, biogas	2002	2.0¢/kWh	2.00¢/kWh			
134	WA	Snohomish County Public Utility District	Planet Power	wind	2002	2.0¢/kWh	2.00¢/kWh			
135	WI	Alliant Energy	Second Nature	wind, landfill gas	2000	2.0¢/kWh	2.00¢/kWh			
136	MI	We Energies	Energy for Tomorrow	wind, landfill gas, hydro	2000	2.04¢/kWh	2.04¢/kWh			

	A	B	C	D	E	F	G	H	I	J
8	State	Utility Name	Program Name	Type	Start Date	Premium				
137	IA	Missouri River Energy Services: Alton, Atlantic, Denison, Fontanelle, Hartley, Hawarden, Kimballton, Lake Park, Manilla, Orange City, Paullina, Primghar, Remsen, Rock Rapids, Sanborn, Shelby, Sioux Center, Woodbine	RiverWinds	wind	2003	2.0¢/kWh-2.5¢/kWh	2.25¢/kWh			
138	MI	DTE Energy	GreenCurrents	wind, biomass	2007	2.0¢/kWh-2.5¢/kWh	2.25¢/kWh			
139	MN	Missouri River Energy Services: Adrian, Alexandria, Barnesville, Benson, Breckenridge, Detroit Lakes, Elbow Lake, Henning, Jackson, Lakefield, Lake Park, Luverne, Madison, Moorhead, Ortonville, St. James, Sauk Centre, Staples, Wadena, Westbrook, Worthingt	RiverWinds	wind	2002	2.0¢/kWh-2.5¢/kWh	2.25¢/kWh			
140	ND	Missouri River Energy Services: City of Lakota	RiverWinds	wind	2002	2.0¢/kWh-2.5¢/kWh	2.25¢/kWh			
141	SD	Missouri River Energy Services: City of Vermillion	RiverWinds	wind	2002	2.0¢/kWh-2.5¢/kWh	2.25¢/kWh			
142	CO	Holy Cross Energy	Local Renewable Energy Pool	small hydro, PV	2002	2.33¢/kWh	2.33¢/kWh			
143	CA	Pasadena Water & Power	Green Power	wind	2003	2.5¢/kWh	2.50¢/kWh			
144	FL	Tampa Electric Company (TECO)	Renewable Energy	PV, landfill, biomass co-firing (wood)	2001	2.5¢/kWh	2.50¢/kWh			
145	IL	City of Naperville / Community Energy	Renewable Energy Option	wind, small hydro, PV	2005	2.5¢/kWh	2.50¢/kWh			
146	IN	Duke Energy	GoGreen Power	wind, PV, landfill gas, digester gas	2001	2.5¢/kWh	2.50¢/kWh			
147	IA	Cedar Falls Utilities	Harvest the Wind	wind	2000	2.5¢/kWh	2.50¢/kWh			
148	LA	Entergy Gulf States	Green Pricing Program	biomass	2007	2.5¢/kWh	2.50¢/kWh			
149	MN	Minnesota Power	WindSense	wind	2002	2.5¢/kWh	2.50¢/kWh			
150	OH	Duke Energy	GoGreen Power	wind, PV, landfill gas, digester gas	2001	2.5¢/kWh	2.50¢/kWh			
151	OR	Midstate Electric Cooperative	Environmentally-Preferred Power	wind	1999	2.5¢/kWh	2.50¢/kWh			
152	WA	Northen Wasco County PUD	Pure Power	wind	2007	2.5¢/kWh	2.50¢/kWh			
153	GA	Georgia Electric Membership Corporation (35 of 42 coops offer program): Altamaha EMC, Amicalola EMC, Canoochee EMC, Carroll EMC, Central Georgia EMC, Cobb EMC, Coastal Electric, Colquitt EMC, Coweta-Fayette EMC, Diverse Power, Flint Energies, Grady EMC, G	Green Power EMC	landfill gas, PV in schools	2001	2.0¢/kWh-3.3¢/kWh	2.65¢/kWh			
154	AL	TVA: City of Athens Electric Department, Cherokee Electric Coop, Cullman Electric Coop, Cullman Power Board, Decatur Utilities, Florence Utilities, Guntersville Electric Board, Hartselle Utilities, Huntsville Utilities, Joe Wheeler EMC, Marshall-DeKalb El	Green Power Switch	landfill gas, PV, wind	2000	2.67¢/kWh	2.67¢/kWh			
155	GA	TVA: Blue Ridge Mountain EMC, North Georgia EMC, Tri-State EMC	Green Power Switch	landfill gas, PV, wind	2000	2.67¢/kWh	2.67¢/kWh			
156	KY	TVA: Bowling Green Municipal Utilities, Franklin Electric Plant Board, Hopkinsville Electric System, Murray Electric System, Pennyrile Rural Electric Coop, Russellville Electric Plant Board, Tri-County Electric, Warren Rural Electric Coop	Green Power Switch	landfill gas, PV, wind	2000	2.67¢/kWh	2.67¢/kWh			
157	MS	TVA: 4-County Electric Power Association, Alcorn Electric Power Association, Central Electric Power Association, Columbus Light & Water, North East Mississippi Electric Power Association, Northcentral MS EPA, City of Okolona Electric Dept., City of Oxford	Green Power Switch	landfill gas, PV, wind	2000	2.67¢/kWh	2.67¢/kWh			
158	NC	TVA: Mountain Electric Cooperative	Green Power Switch	landfill gas, PV, wind	2000	2.67¢/kWh	2.67¢/kWh			
159	TN	TVA: Alcoa Electric Department, Appalachian Electric Cooperative, Athens Utility Board, Bristol Tennessee Electric System, Brownsville Utility Department, Caney Fork Electric Cooperative, Chickasaw Electric Cooperative, Clarksville Department of Electrici	Green Power Switch	landfill gas, PV, wind	2000	2.67¢/kWh	2.67¢/kWh			
160	FL	Keys Energy Services / Sterling Planet	GO GREEN: Florida Ever Green	solar hot water, PV, biomass	2004	2.75¢/kWh	2.75¢/kWh			
161	IA	Associated Electric Cooperative, Inc.: Access Energy Cooperative, Chariton Valley Electric Cooperative, Southern Iowa Electric Cooperative	varies by utility	biomass, wind	2003	2.0¢/kWh-3.5¢/kWh	2.75¢/kWh			
162	KY	East Kentucky Power Cooperative: Blue Grass Energy, Clark, Cumberland, Fleming-Mason, Grayson, Inter-County Energy, Jackson, Licking Valley, Nolin, Owen Electric, Salt River, Shelby, South Kentucky	EnviroWatts	landfill gas	2002	2.75¢/kWh	2.75¢/kWh			
163	MO	Associated Electric Cooperative, Inc.: Black River Electric Cooperative, Boone Electric Cooperative, Callaway Electric Cooperative, Co-Mo Electric Cooperative , Crawford Electric Cooperative, Cuivre River Electric Cooperative, Howell-Oregon Electric Coope	varies by utility	biomass, wind	2003	2.0¢/kWh-3.5¢/kWh	2.75¢/kWh			

	A	B	C	D	E	F	G	H	I	J
8	State	Utility Name	Program Name	Type	Start Date	Premium				
164	OK	Associated Electric Cooperative, Inc.: Central Rural Electric Cooperative	varies by utility	biomass, wind	2003	2.0¢/kWh-3.5¢/kWh	2.75¢/kWh			
165	UT	City of St. George	Clean Green Power	wind, small hydro	2005	2.95¢/kWh	2.95¢/kWh			
166	AZ	Salt River Project	EarthWise Energy	central PV, wind, landfill gas, small hydro, geothermal	1998/2001	3.0¢/kWh	3.00¢/kWh			
167	CA	Los Angeles Department of Water and Power	Green Power for a Green LA	wind, landfill gas	1999	3.0¢/kWh	3.00¢/kWh			
168	CO	Colorado Springs Utilities	Green Power	wind	1999	3.0¢/kWh	3.00¢/kWh			
169	IL	Prairie Power and Community Energy, Inc. (8 of 11 coops offer program): Adams Electric Co-op, Coles-Moultrie Electric, Eastern Illini Electric, McDonough Power, Menard, Rural Electric Convenience Co-op, Shelby Electric, Spoon River Electric Co-op	EcoEnergy	wind	2005	3.0¢/kWh	3.00¢/kWh			
170	IN	Hoosier Energy (6 of 17 coops offer program): Daviess-Martin County REMC, Decatur County REMC, Henry County REMC, South Central Indiana REMC, Southeastern Indiana REMC, Utilities District of Western Indiana REMC	EnviroWatts	landfill gas	2001	2.0¢/kWh-4.0¢/kWh	3.00¢/kWh			
171	IA	Dairyland Power Cooperative: Allamakee-Clayton/Postville, Hawkeye Tri-County/Cresco, Heartland Power/Thompson & St. Ansgar	Evergreen Renewable Energy Program	hydro, wind, landfill gas, biogas	1998	3.0¢/kWh	3.00¢/kWh			
172	MA	Concord Municipal Light Plant (CMLP)	Green Power	hydro	2004	3.0¢/kWh	3.00¢/kWh			
173	MI	Lansing Board of Water and Light	GreenWise Electric Power	landfill gas, small hydro	2001	3.0¢/kWh	3.00¢/kWh			
174	NE	Omaha Public Power District	Green Power Program	landfill gas, wind	2002	3.0¢/kWh	3.00¢/kWh			
175	NM	Xcel Energy	WindSource	wind	1999	3.0¢/kWh	3.00¢/kWh			
176	SC	Santee Cooper: Aiken Electric Cooperative, Berkeley Electric Cooperative, Blue Ridge Electric, Coastal Electric Cooperative, Edisto Electric Cooperative, Fairfield Electric Cooperative, Horry Electric Cooperative, Laurens Electric Cooperative, Lynches Riv	Green Power Program	landfill gas	2001	3.0¢/kWh	3.00¢/kWh			
177	TX	CPS Energy (San Antonio)	Windtricity	wind	2000	3.0¢/kWh	3.00¢/kWh			
178	WA	Grays Harbor PUD	Green Power	wind	2002	3.0¢/kWh	3.00¢/kWh			
179	NM	El Paso Electric	Renewable Energy Tariff	wind	2003	3.19¢/kWh	3.19¢/kWh			
180	VT	Green Mountain Power	Greener GMP	various renewables	2006	3.002¢/kWh-	3.21¢/kWh			
181	NC	Dominion North Carolina Power	NC GreenPower	biomass, hydro, landfill gas	2003	2.5¢/kWh-4.0¢/kWh	3.25¢/kWh			
182	NC	Duke Energy	NC GreenPower	biomass, hydro, landfill gas	2003	2.5¢/kWh-4.0¢/kWh	3.25¢/kWh			
183	NC	ElectriCities: City of Albemarle, Town of Apex, City of Concord, Town of Cornelius, Fayetteville PWC, Town of Granite Falls, Greenville Utilities, City of High Point, Town of Huntersville, City of Kinston, City of Laurinburg, City of Lexington, City of Mo	NC GreenPower	biomass, hydro, landfill gas, PV, wind	2003	2.5¢/kWh-4.0¢/kWh	3.25¢/kWh			
184	NC	NC Electric Cooperatives (22 of 27 coops offer program): Albemarle Electric Membership Corp., Blue Ridge Electric Membership Corp., Brunswick Electric Membership Corp., Carteret Craven Electric Coop., Central Electric Membership Corp., Edgecombe-Martin Co	NC GreenPower	biomass, hydro, landfill gas, PV, wind	2003	2.5¢/kWh-4.0¢/kWh	3.25¢/kWh			
185	NC	Progress Energy / CP&L	NC GreenPower	biomass, hydro, landfill gas	2003	2.5¢/kWh-4.0¢/kWh	3.25¢/kWh			
186	WA	Orcas Power & Light	Go Green	wind, hydro	1999	3.5¢/kWh	3.50¢/kWh			
187	WY	Cheyenne Light, Fuel and Power Company/Bonneville Environmental Foundation	Renewable Premium Program	99% new wind, 1% new solar	2006	3.5¢/kWh	3.50¢/kWh			
188	MI	Upper Peninsula Power Company	NatureWise	wind, landfill gas and animal waste methane	2004	4.0¢/kWh	4.00¢/kWh			
189	SC	Duke Energy Carolinas	Palmetto Clean Energy (PaCE)	wind, solar, landfill gas	2008	4.0¢s;/kWh	4.00¢/kWh			
190	SC	Progress Energy Carolinas	Palmetto Clean Energy (PaCE)	wind, solar, landfill gas	2008	4.0¢/kWh	4.00¢/kWh			
191	SC	SCE&G	Palmetto Clean Energy (PaCE)	wind, solar, landfill gas	2008	4.0¢/kWh	4.00¢/kWh			
192	VT	Central Vermont Public Service	CVPS Cow Power	biogas	2004	4.0¢/kWh	4.00¢/kWh			
193	AL	Alabama Power Company	Renewable Energy Rate	biomass co-firing (wood)	2003/2000	4.5¢/kWh	4.50¢/kWh			
194	GA	Georgia Power	Green Energy	landfill gas, solar	2006	4.5¢/kWh	4.50¢/kWh			
195	AR	Electric Cooperatives of Arkansas: (17 distribution coops) Arkansas Valley Electric Cooperative Corp., Ashley-Chicot Electric Cooperative, Inc., C&L Electric Cooperative Corp, Carroll Electric Cooperative Corp., Clay County Electric Cooperative Corp., Cra	ECA Green Power	hydro	2008	5.0¢/kWh	5.00¢/kWh			
196	CA	Sacramento Municipal Utility District	SolarShares	PV	2007	5.0¢kWh or $30/month	5.00¢/kWh			
197	MO	City Utilities of Springfield	WindCurrent	wind	2000	5.0¢/kWh	5.00¢/kWh			
198	CO	Intermountain Rural Electric Association / Sterling Planet	National Solar	solar	2006	5.5¢/kWh	5.50¢/kWh			
199	MA	Shrewsbury Electric and Cable Operations	SELCO GreenLight	wind	2007	6.67¢/kWh	6.67¢/kWh			
200	AZ	Tucson Electric	GreenWatts	landfill gas, PV	2000	10¢/kWh	10.00¢/kWh			
201	AZ	UniSource Energy Services	GreenWatts	PV	2004	10¢/kWh	10.00¢/kWh			
202	FL	City of Tallahassee/Sterling Planet	Green for You	PV only	2002	11.6¢/kWh	11.60¢/kWh			
203	AK	Golden Valley Electric Association	Sustainable Natural Alternative Power (SNAP)	various local projects	2005	Contribution				
204	CA	Anaheim Public Utilities	Sun Power for the Schools	PV	2002	Contributio				
205	CO	Xcel Energy	Renewable Energy Trust	PV	1993	Contributio				
206	FL	Utilities Commission City of New Smyrna Beach	Green Fund	local PV projects	1999	Contribution				

	A	B	C	D	E	F	G	H	I	J
8	State	Utility Name	Program Name	Type	Start Date	Premium				
207	HI	Hawaiian Electric	Sun Power for Schools	PV in schools	1997	Contributio n				
208	HI	Kauai Island Utility Cooperative	Green Rate	distributed renewable energy systems	TBD	TBD				
209	IL	City of St. Charles/ComEd and Community Energy, Inc.	TBD	wind, landfill gas	2003	Contributio n				
210	IA	Farmers Electric Cooperative	Green Power Project	biodiesel, wind	2004	Contributio n				
211	IA	Iowa Association of Municipal Utilities (84 of 137 munis offer program) Afton, Algona, Alta Vista, Aplington, Auburn, Bancroft, Bellevue, Bloomfield, Breda, Brooklyn, Buffalo, Burt, Callender, Carlisle, Cascade, Coggon, Coon Rapids, Corning, Corwith, Danv	Green City Energy	wind, biomass, PV	2003	Varies by ut ility				
212	IA	MidAmerican Energy	Renewable Advantage	wind	2004	Contributio				
213	IA	Muscatine Power and Water	Solar Muscatine	PV	2004	Contributio				
214	IA	Waverly Light & Power	Green Power Choice	wind	2003	Contributio				
215	MN	Austin Utilities, Owatonna Public Utilities, Rochester Public Utilities	SolarChoice	local PV systems	2006	Contributio n				
216	NV	Sierra Pacific Resources: Nevada Power	Desert Research Institute's GreenPower Program	PV on schools	Unknown	Contributio n				
217	NV	Sierra Pacific Resources: Sierra Pacific Power	Desert Research Institute's GreenPower Program	PV on school	unknown	Contributio n				
218	OR	PacifiCorp: Pacific Power	Blue Sky QS (Commercial Only)	wind	2004	Sliding scale depending				
219	TX	College Station Utilities	Wind Watts (10%/50%/100%)	new wind	2009	TBD				
220	VT	Green Mountain Power	CoolHome / CoolBusiness	wind, biomass	2002	Contributio n				
221	WA	Benton County Public Utility District	Green Power Program	landfill gas, wind, hydro	1999	Contributio n				
222	WA	Chelan County PUD	Sustainable Natural Alternative Power (SNAP)	PV, wind, micro hydro	2001	Contributio n				
223	WA	Seattle City Light	Seattle Green Power	PV, biogas	2002	Contributio				
224	WI	Wisconsin Public Service	Solar Wise for Schools	PV in schools	1996	Contributio n				
225	**Source:** National Renewable Energy Laboratory, Golden, Colorado.									
226										
227	**Notes:** Utility green pricing programs may only be available to customers located in the utility's service territory.									
228										
229	Not finding the program you were looking for? Please refer to our other tables in Information Resources or go directly to Buying Green Power page.									
230										
231										
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(END OF ATTACHMENT A)

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DONNA L. BARRY

Q 1 Please state your name and business address.

A 1 My name is Donna L. Barry, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a regulatory principal in the Electric Proceedings section of the Energy Proceedings Department, under the Vice President of Regulation and Rates. I am responsible for developing testimony and analysis to support proceedings filed at the Commission on matters related to energy procurement.

Q 3 Please summarize your educational and professional background.

A 3 I received my bachelor of science degree in civil engineering from Washington State University and a master of business administration degree from Santa Clara University.

I began my career with PG&E in 1989 as an engineer in the Engineering and Construction Business Unit's Gas Construction Department, managing gas distribution and pipeline replacement construction projects. From there, I took an assignment in the Gas Supply Business Unit in the Gas Engineering and Construction (GEC) Department before joining the Gas Planning section in GEC. I subsequently joined the Cost of Service section in the Rates Department where I performed cost of service studies and marginal cost analyses supporting various gas and electric rate applications. I joined the Electric Restructuring Cost Recovery section of the Revenue Requirements Department in 2001 and Electric Energy Revenue and Analysis and Ratemaking section in 2002 where I've been responsible for a variety of procurement-related regulatory filings and analyses, including sponsoring testimony on electric procurement cost forecasts and compliance matters. The department and section were renamed as the Energy Proceedings Department and the Electric Proceedings section at the end of 2007.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring Chapter 1, “Introduction and Power Charge Indifference Amount Modification,” in the Direct Access Reopening OIR.
Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF SHAHROKH HESSAMI

Q 1 Please state your name and business address.

A 1 My name is Shahrokh Hessami, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am director of Risk Management in charge of credit risk and risk control, under the Chief Risk and Audit Officer organization. I am responsible for developing testimony to support proceedings filed at the Commission related to Risk Management.

Q 3 Please summarize your educational and professional background.

A 3 I received my bachelor of arts degree in applied mathematics from University of California at Berkeley and a master of science degree in industrial and systems engineering from San Jose State University.

I began my career with PG&E in 1991 serving the company at various positions in revenue requirement, energy trading and power market planning through1997. Since 1997, I have served various positions outside of PG&E including Chief Risk Officer at Cook Inlet Energy, Corporate Credit Risk Executive at Countrywide Financial and briefly with Bank of America during the merger of the organizations, and Chief Risk Officer at Juice Energy. I rejoined PG&E as director of Risk Management in 2009.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring Chapter 4, “Security Requirements” in the Direct Access Reopening OIR.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MARC L. RENSON

Q 1 Please state your name and business address.

A 1 My name is Marc L. Renson, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a principal in the Long-Term Energy Policy section of the Energy Policy, Planning & Analysis Department, under the Senior Vice President of Energy Procurement. I am responsible for developing testimony and analysis to support proceedings filed at the Commission on matters related to energy procurement.

Q 3 Please summarize your educational and professional background.

A 3 I received my bachelor of science degree in civil engineering from the University of California at Berkeley.

I began my career with PG&E in 1979 as a field engineer in the General Construction Department, overseeing the building of the Helms Pumped Storage hydroelectric project. In 1981, I joined the Siting Department where I worked on the development of the first three standard offers for Qualifying Facilities (QF) and then proceeded to negotiate and renegotiate a number of contracts with renewable and cogeneration QFs. Between 1981 and 1994, the Siting Department went through a number of name changes that included Generation Planning, Cogeneration and QFs, QFs, Electric Supply, and Power Contracts. In 1994, I joined the Electric Settlement Department where I became responsible for the overall settlement administration of the QF contracts, and starting in 2003, the Department of Water Resources and new bilateral contracts. In 2008, I joined the Energy Policy, Planning & Analysis Department where I became Energy Procurement's lead person on Direct Access and Community Choice Aggregation issues.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring Chapters 2 and 3 in the Direct Access Reopening OIR:

- Chapter 2, "Transitional Bundled Service Rates."
- Chapter 3, "Switching Rules."

Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.