Docket No.: R.07-05-025

Exhibit No.: ________________

Date: January 31, 2011

Witnesses: John P. Dalessi, Mark F. Fulmer, Margaret A. Meal

TESTIMONY OF
JOHN P. DALESSI
MARK E. FULMER
MARGARET A. MEAL
ON BEHALF OF
THE JOINT PARTIES
ON
A FAIR AND REASONABLE METHODOLOGY TO DETERMINE THE POWER CHARGE INDIFFERENCE ADJUSTMENT (PCIA) AND THE COMPETITION TRANSITION CHARGE (CTC)

I. QUALIFICATIONS OF WITNESSES AND SUMMARY OF TESTIMONY

A. QUALIFICATIONS

Q. Ms. Meal, please state your name, position, and address.

A. My name is Margaret A. Meal. I am Manager of Regulatory and Legislative Affairs with the Power Enterprise at the San Francisco Public Utilities Commission ("SFPUC"), a department of the City and County of San Francisco ("CCSF" or "the City"). My business address is 1155 Market St., San Francisco, CA 94103.

Q. Please describe your background.

A. I joined the SFPUC in February of 2010 and am responsible for responding, on behalf of CCSF, to a variety of State electricity issues impacting the policy choices available to CCSF. I have worked in the electric power industry for my entire professional career (over twenty years), primarily as a consultant advising business interests, public agencies, investors, lenders and regulatory agencies on financial and economic issues, including asset valuation, risk assessment, financing alternatives, utility cost of capital and ratemaking. I have provided written and oral testimony to this Commission and other state public utility commissions on numerous occasions. My resume is attached as Exhibit D.

Q. Mr. Fulmer, please state your name, position, and address.

A. My name is Mark E. Fulmer. I am a Principal at MRW & Associates, LLC. My business address is 1814 Franklin Street, Suite 720, Oakland, California, 94612.

Q. Please describe your background.

A. I have been an energy consultant with MRW since 1999. During that time, I have worked with end-use customers, energy service providers, independent power producers, municipalities, trade organizations and financial institutions on a variety of matters related to natural gas and electric industry restructuring, utility ratemaking, price forecasting, and asset valuation. I hold a Master of Science degree in Engineering from Princeton University and a Bachelor of Science degree in Engineering from the University of California at Irvine. My resume is attached as Exhibit C.

Q. Mr. Dalessi, please state your name, position, and address.

A. My name is John Dalessi. I am Principal of Dalessi Management Consulting LLC. My business address is 3941 Park Drive, Suite 20-201, El Dorado Hills, CA, 95762.

Q. Please describe your background.

A. I provide consulting services to public and private sector clients in the energy industry. Among other responsibilities, I am a consultant to the Marin Energy Authority ("MEA") and assist MEA in resource planning, procurement, ratemaking and regulatory compliance. During my twenty-year career in energy, I worked for Southern California Edison Company, Pacific Gas and Electric Energy Services, the Automated Power Exchange, Inc. and Navigant Consulting in the following areas among others: electricity procurement, resource planning, transmission contracts, regulatory advocacy and compliance, business and strategic planning, electricity revenue allocation and rate design, pricing structures for the competitive retail electricity market rate, and statewide demand response programs. My resume is attached as Exhibit B.

Q. On whose behalf are you testifying?

A. We are submitting testimony on behalf of the Joint Parties, comprised of the Direct Access Customer Coalition, the Alliance for Retail Energy Markets, the City and County of San Francisco, the Marin Energy Authority, the Energy Users Forum, Blue Star Energy, the San Joaquin Valley Power Authority, and the California Municipal Utilities Association.

Q. What is the interest of the Joint Parties in this proceeding?

A. The Joint Parties include current and prospective energy service providers ("ESPs") and Community Choice Aggregators ("CCAs"), and the trade association for publicly owned utilities ("POUs"). The Joint Parties are concerned that the methodology used to calculate the Power Charge Indifference Adjustment ("PCIA") and ongoing Competition Transition Charge ("CTC") is flawed. Specifically, the Market Price Benchmark used in the methodology is too low. As a result, the PCIA and CTC applicable to customers that choose alternative energy suppliers or depart from Investor Owned Utility ("IOU") service ("Departing Customers") do not provide for bundled customer indifference to the departure of load, which the Commission has described as the guiding principle for applying non-bypassable charges. In fact, the current methodology results in bundled customer costs (and rates) that are too low, and costs (and rates) for Departing Customers that are too high. The Joint Parties propose to revise the methodology used to calculate the Market Price Benchmark ("MPB") in order to achieve the goal of bundled customer indifference.

B. SUMMARY

Q: Can you please summarize your testimony?

A: Yes. Our testimony shows that the current methodolo gy for determining the PCIA and CTC is seriously flawed and needs to be fixed. As currently structured, Departing Customers bear a disproportionate share of the IOUs' procurement costs, and the cost burden of those disproportionate costs is substantial. For many years, the Commission has set forth a guiding principle that Departing Customers should pay non-bypassable charges for IOU procurement costs that are structured to achieve "bundled customer indifference" to the departure of load. As currently str uctured, the PCIA and CTC are clearly excessive and bundled customer indifference is not achieved. This places an unfair cost burden on Departing Customers, and, moreover, provides the IOUs with an unfair competitive advantage compared to service from alternative energy service providers, including CCAs, ESPs and POUs.

Our testimony shows that the calculations used to determine the PCIA and CTC are flawed because they do not properly account for (i) renewable attributes, (ii) load profile, (iii) capacity attributes, and (iv) California Independent System Operator ("CAISO") costs. These flaws result in estimated above-market costs and the resulting PCIA and CTC that are significantly overstated. For example, our testimony shows that for 2011, the current methodology results in IOU above-market costs in excess of $4 billion. For PG&E, this results in the PCIA and CTC representing 37% of PG&E's generation costs. A more reasonable methodology that achieves bundled customer indifference would reduce these non-bypassable charges for PG&E by more than 80%. Results for SCE are similar; a more reasonable methodology would reduce these non-bypassable charges for SCE by 60%.

Q. Please summarize the Joint Parties' Proposal to modify th e current methodology to determine the PCIA and CTC.

Our testimony sets forth proposals to correct the methodology used to determine total portfolio costs and calculate the Market Price Benchmark in order to (1) reflect in the benchmark the value of renewable resources, (2) reflect in the benchmark the value of shaping resources to the load, (3) more accurately reflect in the benchmark the value of capacity, and (4) more accurately account for load-based CAISO costs.

The Joint Parties' proposed revisions to the Market Price Benchmark are:

1. Use a Green Benchmark to reflect the value of Renewables Portfolio Standard ("RPS")-compliant supplies, based on the RPS content o f each vintaged total portfolio.

2. Determine the Green Benchmark for a given year based on the forecasted weighted-average cost for that year of IOU RPS-compliant resources that are in their first and second year of deliveries. The Green Benchmark would be the same for all three IOUs.

3. Modify the current "flat" weighted-average of cost of co mmodity power to reflect a weighted-average cost based on the IOU's forecasted bundled system load shape.

4. Modify the current fixed capacity adders to market-based capacity adders that are based upon the CAISO's capacity procurement mechanism ("ICPM") price and the net qualifying capacity ("NQC") for each vintaged Total P ortfolio.

5. Include an adder to reflect the cost of congestion between the NP15/SP15 trading points and the IOUs' Load Aggregation Points.

The Joint Parties' proposed revisions to the determination of costs to be included in vintaged Total Portfolio Costs are:

6. Exclude all load-based CAISO charges and costs from Total Portfolio Costs.

7. Treat the cost of short-term purchases and sales consistently across all three IOUs.

Taken together, these revisions will remove the significant flaws in the current methodology and will result in PCIA and CTC that come much closer to the goal of setting these charges at levels that protect bundled customers from incurring additional costs as the result of load departure, without imposing unfair and undue cost burdens on Departing Customers.

Q. Do you have a recommendation on when the revised methodology should be implemented?

A. Yes. The revised methodology should be implemented as soon as possible, to mitigate the adverse impact on Departing Customers, and to ensure bundled customer indifference. All the data necessary for revisions to the 2011 CTC and PCIA are already available as part of each IOU's 2011 Energy Resource Recovery Account ("ERRA") forecast applications. There is no reason to delay.

II. THE GOAL OF THE PCIA/CTC METHODOLOGY IS TO ACHIEVE BUNDLED CUSTOMER INDIFFERENCE TO DEPARTURE OF LOAD, BUT THE CURRENT METHODOLOGY FAILS TO DO SO AND IS SIGNIFICANTLY FLAWED

A. BUNDLED CUSTOMER INDIFFERENCE AND THE CURRENT METHODOLOGY

Q: Please explain what is meant by bundled customer indifference as it relates to the calculation of PCIA and CTC.

A: In determining appropriate cost responsibility surcharges ("CRS") and other non-bypassable charges ("NBCs") applicable to Departing Customers, the Commission has consistently applied the principle of "bundled customer indifference" to ensure that bundled customers are not subject to additional costs, <u>nor do they benefit</u>, as the result of a Departing Customer's choice to use an alternative energy supply provider.

For example, in Decision 04-12-048 ("D.04-12-048"), Finding of Fact 28, the Commission stated, "The threshold policy issue underlying cost responsibility surcharges is to ensure that remaining bundled ratepayers remain indifferent to stranded costs left by the departing customers." In Decision 08-09-012 ("D.08-09-012"), the Commission confirmed this principle again, stating, "In addressing issues related to NBCs, the Commission has generally applied the bundled customer indifference principle, whereby *bundled customers should be no worse off, nor should they be any better off* as a result of customers choosing alternative energy suppliers (ESP, CCA, POU or customer generation).. It is reasonable that we continue to use these guiding principles in reconciling issues related to the implementation of D.04-12-048 and D.06-07-029 NBCs." (p. 10, emphasis added)

Q. Please describe the PCIA and CTC and the current methodology for determining them.

A. The PCIA and CTC are two components of the Cost Responsibility Surcharge that are applicable to most Departing Customers. Taken together, PCIA and CTC are intended to collect any above-market costs associated with procurement commitments made by an IOU on behalf of Departing Customers, before they departed IOU service. These commitments assigned to Departing Customers can include both utility-owned generation ("UOG") and power purchase agreements ("PPAs").

The current methodology to calculate the PCIA and CTC utilizing a Market Price Benchmark was first established in D.06-07-030 and refined in D.07-01-030. The methodology attempts to calculate an "Indifference Amount," the difference between the cost of the IOU's "Total Portfolio" of resources for a given vintage of load and the market value of that Total Portfolio, as follows:

1. Estimate the total costs of procurement commitments made on behalf of both bundled and Departing Customers, before they departed IOU service (the vintaged Total Portfolio Cost).
2. Estimate the market value of those supplies based on a MPB.
3. Subtract the market value of the supply portfolio from the cost of the supply portfolio to determine the Indifference Amount.
4. Assign the Indifference Amount to the bundled and Departing Customers responsible for the supply portfolio, and determine the PCIA and CTC for the Departing Customers based on the Departing Customers' pro-rata share of the Indifference Amount.

Currently, Indifference Amounts, PCIA and CTC revenue requirements, and resulting PCIA and CTC are determined annually in the IOUs' ERRA proceedings, based on forecasted costs associated with the IOUs' procurement commitments (supply portfolio) for the upcoming year, and on a formula for the Market Price Benchmark. To the extent that either (i) forecasted costs of supplies are overstated (vintaged total portfolio costs are too high), or (ii) the formula for the Market Price Benchmark understates the market value of the supply portfolio (the Market Price Benchmark is too low), both the PCIA and CTC will be overstated, bundled customers will bear less than their fair share of procurement costs at the expense of Departing Customers, and bundled customer indifference will not be achieved.

Q. What kinds of procurement commitments are covered by this calculation?

A. The method for calculating the PCIA and CTC is intended to include all commitments for power supplies made to serve vintaged bundled load. This total portfolio of supplies is structured to meet the characteristics of the load and includes both non-renewable supplies and the renewable supplies procured to meet the RPS requirements.

Q. Please explain the difference between the PCIA and CTC.

A. Both the PCIA and CTC are surcharges that are intended to collect the above-market costs associated with specific generation commitments (specific supply portfolios) made by the IOUs. The CTC represents the above-market costs of a specific subset of supply. The PCIA covers all other eligible supplies assigned to load according to its vintage. For example, the PCIA supply portfolio for a particular vintage year would include the IOUs' "old-world" utility-owned resources (hydro, nuclear and fossil), Department of Water Resources contracts, and any other IOU renewable and non-renewable supply commitments assigned to that vintage year, which could include both PPAs for supplies and new utility-owned facilities. Taken together, the CTC and PCIA generation commitments make up the "Total Portfolio" of resources assigned to a particular vintage of Departing Customers.

Q. Are both the PCIA and CTC determined using the same Market Price Benchmark?

A. Yes. Under the current methodology, an Indifference Amount is determined for the total portfolio of resources (PCIA and CTC) using the Market Price Benchmark. Any above-market costs associated with the CTC resources are determined using the same Market Price Benchmark that is used for determining the Indifference Amount, and the CTC costs are subtracted from the Indifference Amount to determine the PCIA revenue requirement. So the Total Portfolio of resources, both the PCIA portion and the CTC portion, are all valued using the same Market Price Benchmark.

Q. What is the current formula for the Market Price Benchmark?

A. The current Market Price Benchmark formula is based on a published forward price for base load, system energy, plus adders for capacity and distribution losses. For example, for PG&E, in 2011, the formula is:

1. A published index price for power at NP15 for calendar year 2011, weighting on-peak and off-peak prices by the number of hours in each period (equating to a flat, constant, 24 hour a day delivery), plus
2. \$4/MWh to reflect the value of capacity/resource adequacy, times
3. A distribution loss factor of 1.06 to account for losses from the NP15 delivery point to customer meters.[1]

[1] The formula was first established in D.06-07-030 and later modified to the current formula in D.07-01-030. The formulae for SCE and SDG&E are similar, but use SP15 forward prices, a capacity adder of \$7/MWh, and loss factors of 1.053 for SCE and 1.043 for SDG&E.

B. THE FLAWS IN THE METHODOLOGY TO CALCULATE THE PCIA AND CTC

Q. Have you identified any problems with the current method for calculating the PCIA and CTC?

A. Yes. The current methodology is flawed because it is unbalanced, in that the Market Price Benchmark used to value the supply portfolio excludes several attributes included in the cost of the supply portfolio. First, the Market Price Benchmark is too low because it does not reflect the value of renewables that are included in the supply portfolio used to determine the portfolio cost. Second, the Market Price Benchmark excludes the value of certain components of the supply portfolio that are necessary to shape the supply to serve the load. Third, the Market Price Benchmark does not accurately value capacity. Fourth, the Market Price Benchmark does not accurately account for CAISO costs. A side-by-side comparison of the attributes included in the supply portfolio and the attributes included in the Market Price Benchmark is shown in the table below.

The Current Methodology is Unbalanced

Supply Attribute	**Vintaged Supply Portfolio Cost**	**Market Price Benchmark**	**Result**
Renewable Attributes	Includes non-RPS and RPS resources	Non-RPS only	MPB too low; Indifference Amount overstated
Supply Shaped to Load	Supply is shaped to system load profile	Flat 24x7 delivery profile	MPB too low; Indifference Amount overstated
Capacity	Includes capacity attributes	Includes Capacity Adder not tied to market prices	Varies with market value of capacity
CAISO Services and Distribution Losses	Is delivered to the customer meter: - including CAISO costs - including distribution losses	Is delivered to SP15/NP15: - excluding CAISO costs - including distribution losses	Vintaged Supply costs too high; Indifference Amount overstated

Each of these errors needs to be corrected in order to achieve bundled customer indifference. Further, three of these errors systematically <u>overstate</u> Indifference Amounts. Overstated Indifference Amounts result in the PCIA and CTC being too high, such that Departing Customers bear a disproportionate share of procurement costs, and bundled customer indifference is not achieved. Each of these three errors, and the magnitude of the distortion, is described further below.

C. THE CURRENT MARKET PRICE BENCHMARK DOES NOT REFLECT THE MARKET VALUE OF RENEWABLE RESOURCES

Q. Does the forward contract price used to calculate the Market Price Benchmark include any renewable attributes, such as Renewable Energy Credits ("RECs")?

A. No. In the current methodology, the forward contract price is for a delivered quantity of energy over a one-year period. No renewable attributes are included in the price, nor in the contracted deliveries. Thus, the Market Price Benchmark reflects only a price for system power, base-load deliveries, while the IOUs' supply portfolio includes RPS-eligible supplies.

Q. Why does this lead to overstated Indifference Amounts?

A. The IOUs are required to meet specific procurement obligations related to California's RPS requirements. To meet these obligations, the IOUs are procuring or building increasing amounts of renewable resources. At this time, renewable resources are more costly than "brown" system power. While the cost of more expensive renewable resources is reflected in the costs of the IOUs' portfolios used to determine the PCIA and CTC, the value of RPS resources is not reflected in the Market Price Benchmark. Thus, bundled customers get both full credit for the renewable resources procured by their IOU, and a contribution toward the costs of those renewables from Departing Customers. Bundled customers benefit further because as load departs for service from an alternative provider, renewable attributes are freed up to serve bundled load, and future renewable procurement needs for the IOUs' bundled customers are reduced.

Q. Please provide an example of what you mean by the benefit of renewable attributes that are freed up by Departing Customers and in turn a reduction in renewable procurement needs for bundled customers.

A. When load departs, an IOU can retain the renewable resources, and the renewable attributes associated with them, and use them to serve the load that continues to be served by the IOU. To the extent that the IOU is not in compliance with RPS requirements, or can forward-bank renewable attributes for use in future periods where RPS requirements will not be met (*e.g.*, because the RPS requirement is increasing), the renewable attributes left behind will be available for those purposes.

For example, consider a situation where a utility has 100 MWh/yr of bundled load to serve, and the following circumstances:

- Current Portfolio includes 15 MWh RPS (15%)
- 10 MWh (10%) of load departs
  - Bundled load is reduced to 90 MWh
  - RPS procurement remains at 15 MWh
  - RPS compliance increases from 15% to 17%

This additional RPS increment (2%) can be banked or used currently for the IOUs' remaining bundled load, thus avoiding future additional renewable procurement costs for those remaining bundled customers. However, nothing in the current methodology accounts for or credits those cost savings.

Q. What is the adverse impact of this flaw on Departing Customers?

A. Departing Customers pay for the cost of the renewables in their IOU's portfolio but are assigned none of the renewable value. Further, the alternative energy suppliers that serve Departing Customers (CCAs, ESPs, and POUs) must comply with RPS requirements. Thus, in addition to paying for a portion of the renewables procured by the IOUs for their customers, Departing Customers must also pay for renewable resources procured by their alternative supplier to meet their own RPS requirements. The result is that Departing Customers pay for renewable resources twice, but only get credit for the renewable resources procured by their alternative supplier.

<u>D. THE CURRENT MARKET PRICE BENCHMARK DOES NOT REFLECT THE MARKET VALUE OF LOAD SHAPING</u>

Q. You also mentioned that the value of load shaping is not reflected in the Market Price Benchmark. Please explain.

A. The supply portfolio that is being valued is a diverse portfolio of resources that is designed to meet the electricity needs of each IOU's bundled customers. An IOU's costs for that supply (the cost side of the calculation) are forecasted based on how the portfolio will operate to serve that IOU's bundled load, and includes the cost of shaping supply portfolio deliveries to match the shape of the load. Departing Customers are assigned a "slice" of the cost of that supply portfolio, including the cost of shaping.

Q. How could time of delivery or the shaping of supplies to the load impact the value of the supply portfolio?

A. The current Market Price Benchmark reflects the value of supply delivered evenly over every hour in the year, corresponding to a load factor of 1.0. An IOU's supply portfolio serves a load with proportionately more load in more expensive, on peak hours, corresponding to a load factor well below 1.0. As an example, in April 2010, NP15 on-peak forward prices for 2011 exceeded off peak prices by about $14/MWh,[2] and, for 2011, PG&E's load is projected to have a load factor of 0.53.[3]

E. THE CURRENT MARKET PRICE BENCHMARK INCLUDES STAL E ADDERS TO REFLECT THE VALUE OF CAPACITY

Q. Does the current Market Price Benchmark account for the value of capacity?

A. Yes. The current MPB includes static capacity adders that were the result of a settlement among parties in 2006, when the resource adequacy program was just getting underway.

Q. Does this method accurately reflect the value of capacity?

A. No. The capacity value should be updated annually, other wise there is the risk that the value becomes stale over time and deviates from then-current market values, which would distort the MPB. While the IOUs were the first to identify this problem during the recent workshops, the Joint Parties agree that the methodology to reflect the value of capacity in the MPB should be updated.

F. THE CURRENT MARKET PRICE BENCHMARK DOES NOT ACCU RATELY ACCOUNT FOR CAISO COSTS

Q. Does the current Market Price Benchmark accurately acc ount for CAISO costs?

A. No. In at least one cases, the IOUs include cert ain CAISO charges in their forecast of portfolio costs, such as grid management charges and FERC fees, ancillary services, and unaccounted for energy and neutrality fees, however, the value of these services is not

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[2] Based on the average of on-peak and off-peak prices at NP15 for all trading days in April 2010, as published by Compagnie Financière Tradition (see www.tradition.com).

[3] PG&E response to CCSF data request CCSF-001 in PG&E's 2011 ERRA Forecast Application A.10-05-022, question 16.

currently reflected in the MPB.[4] Many CAISO costs are load-based or volumetric charges that an IOU would avoid when its load is reduced. Therefore, CAISO costs that an IOU will avoid when customers depart IOU service should not be included on the cost side of the equation, unless the Market Price Benchmark reflects their value to the supply portfolio, which it currently does not. These costs are not immaterial. For example, PG&E forecasts CAISO costs in 2011 to be $63 million, and these costs account for nearly 4% of the above-market costs of the PCIA and CTC resources assigned to vintages 2010 and 2011.[5] Moreover, for certain IOUs, there may be a need to modify the current weighted-average cost of commodity power to reflect the cost of congestion between NP15/SP15 trading points and the IOUs' Load Aggregation Points.

G. THE RESULTING DISTORTIONS IN THE MARKET PRICE BENCHMARK ARE SIGNIFICANT

Q. How significant is the impact of the flaws you describe above on the PCIA and CTC?

A. The flaws described above result in Market Price Benchmarks that are significantly lower than what they should be, and Indifference Amounts, PCIA and CTC that are significantly higher than what they should be. The extent of the distortions described above can be demonstrated using comparisons of current Market Price Benchmarks to recent actual market data. The Market Price Benchmark should reflect the forecasted price of buying/selling a given supply portfolio for a given time period. Absent significant market movements, the Market Price Benchmark used for 2011 should be comparable to recent market data. However, the respective Market Price Benchmarks adopted or proposed for use in 2011 diverge significantly from the prices paid for supplies based on recent market transactions, including the price of the IOUs' own recent procurements, which presumably reflect market prices.

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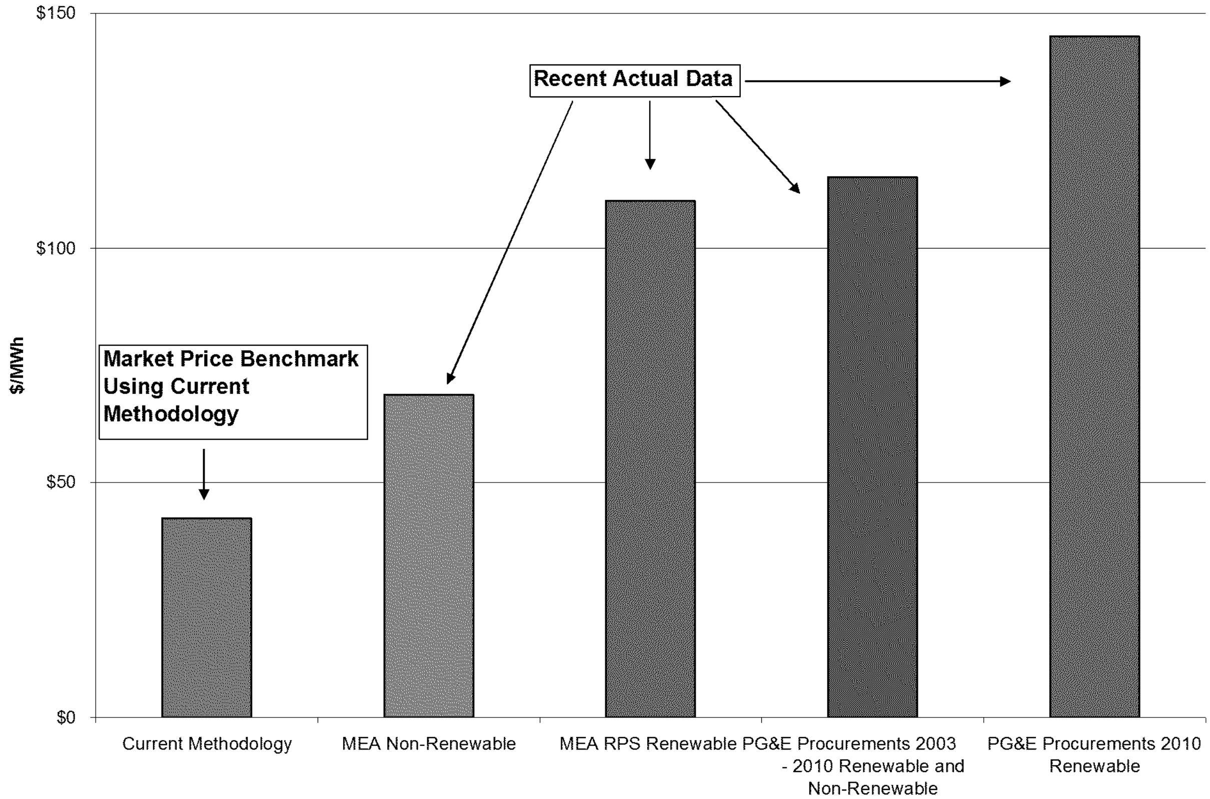
[4] For example, PG&E included certain CAISO costs as part of its Total Portfolio Costs in its 2011 ERRA Forecast application. See PG&E Testimony in its 2011 ERRA Forecast application, A.10-05-022 Chapter 3, p. 3-15.

[5] See PG&E workpapers to Chapter 7, Indifference details 2011 ERRA, in its 2011 ERRA Forecast Application A.10-05-022, November 2010 update.

For example, the chart below compares the Market Pri ce Benchmark adopted for 2011 for PG&E (based on forward prices from October 2010) to other relatively recent price points:

1. The price of non-renewable supplies to serve a portion of the Marin Energy Authority's CCA load in 2011, where that commitment was made in March 2010.
2. The price of RPS-eligible renewable supplies to serve a portion of the Marin Energy Authority's CCA load in 2011, where that commitment was made in March 2010.
3. PG&E recent procurement costs, 2003-2010: The cost of supplies to serve PG&E's bundled customers in 2011, from procurement commitments made by PG&E from 2003 through 2010 (with these supplies including both renewable and non-renewable supplies).
4. PG&E recent procurement costs, 2010 activity only: The cost of 2011 supplies based on PG&E's most recent procurement commitments, those made in 2010 only. According to PG&E, these supplies are all RPS-eligible.

Current Market Price Benchmark Compared to Recent Market Data ~~–~~PG&E

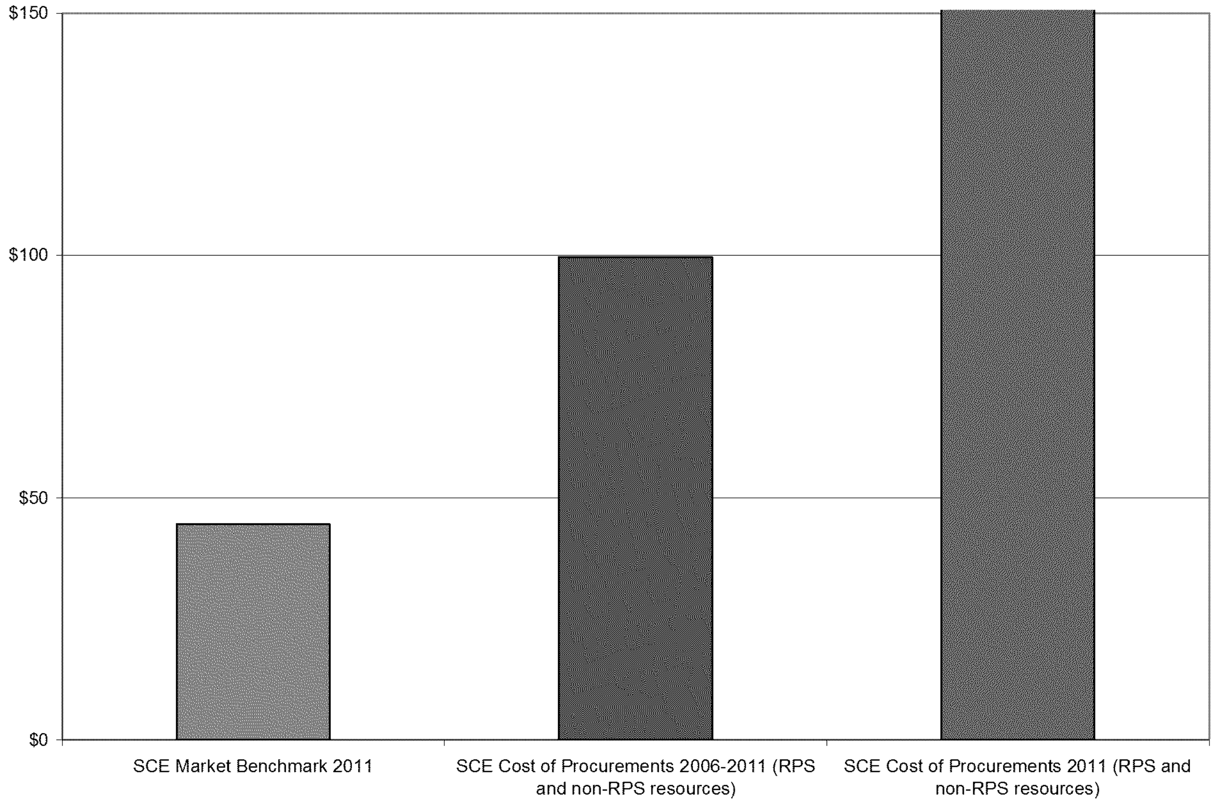


In all cases, price points from recent transactions are well in excess of the Market Price Benchmark. For example, PG&E's own recent procurements are priced at 2-3 times PG&E's 2011 Market Price Benchmark. These data show that the Market Price Benchmark is a poor indicator of the market value of the supply portfolio, since buyers recently paid prices well above the Market Price Benchmark for the type of supplies that comprise PG&E's portfolio.

Q. Do you have a similar comparison for SCE?

A. Yes. Results for SCE, based on its 2011 ERRA Forecas t application, are shown in the chart below. In this chart, SCE's procurement costs are not disaggregated into renewable and non-renewable supplies (as that disaggregation is not disclosed in SCE's public filings), but are disaggregated by the year the commitment was made (supply vintage). Again, price data from SCE's own recent procurements are well in excess of SCE's Market Price Benchmark.

Current Market Price Benchmark Compared to Recent Market Data–SCE



Q. Do you have a similar comparison for SDG&E?

A. No. SDG&E's ERRA forecast for 2011 is not yet complete, and the materials filed to date do not include the necessary level of detail on SDG&E's Market Price Benchmark nor its vintaged supply portfolio costs.

Q. Can you estimate how much the 2011 Market Price Benchmarks for PG&E and SCE would change if renewable attributes of the supply portfolio were included?

A. Yes. One way to estimate how much the Market Price Benchmark would change if renewable attributes were included is to 1) use the 2011 forecasted cost of PG&E's own renewable commitments made in 2010 ($145/MWh) as a proxy for their market value in 2011,[6] 2) use that price instead of the current Market Price Benchmark for 20% of the supply portfolio (the current 2011 RPS requirement), and 3) use the current Market Price Benchmark for the remaining 80% of the supply portfolio. For 2011, the Market Price

[6] Note: similar data for SCE was not made available in SCE's 2011 ERRA Forecast Application, so $145/MWh is used here for both SCE and PG&E.

Benchmarks included in the November 2010 updates to PG&E's and SCE's 2011 ERRA Forecast applications are $42.42/MWh (PG&E) and $44.51/MWh (SCE).

This approach results in a Market Price Benchmark of $63-$65/MWh, nearly 50% higher than the $42-$45/MWh using the current methodology.[7] Thus, the failure to reflect the current market price of renewable supplies in the Market Price Benchmark creates a significant and unfair distortion in Indifference Amounts, the PCIA and CTC. Note that this is before incorporating further adjustments necessary to properly account for load shape and CAISO costs.

As further detailed in our testimony below, we are not proposing to modify the current methodology using $145/MWh as the Green Benchmark component of the Market Price Benchmark. Here, this price point is only used to clearly demonstrate the significant distortion in the current methodology. The testimony below details our specific proposed modifications to the current methodology and the Market Price Benchmark. Unfortunately, we do not have access to the data necessary to calculate the result of application of our proposed modifications to the 2011 Market Price Benchmarks, as the IOUs have stated that the data necessary are proprietary and confidential.

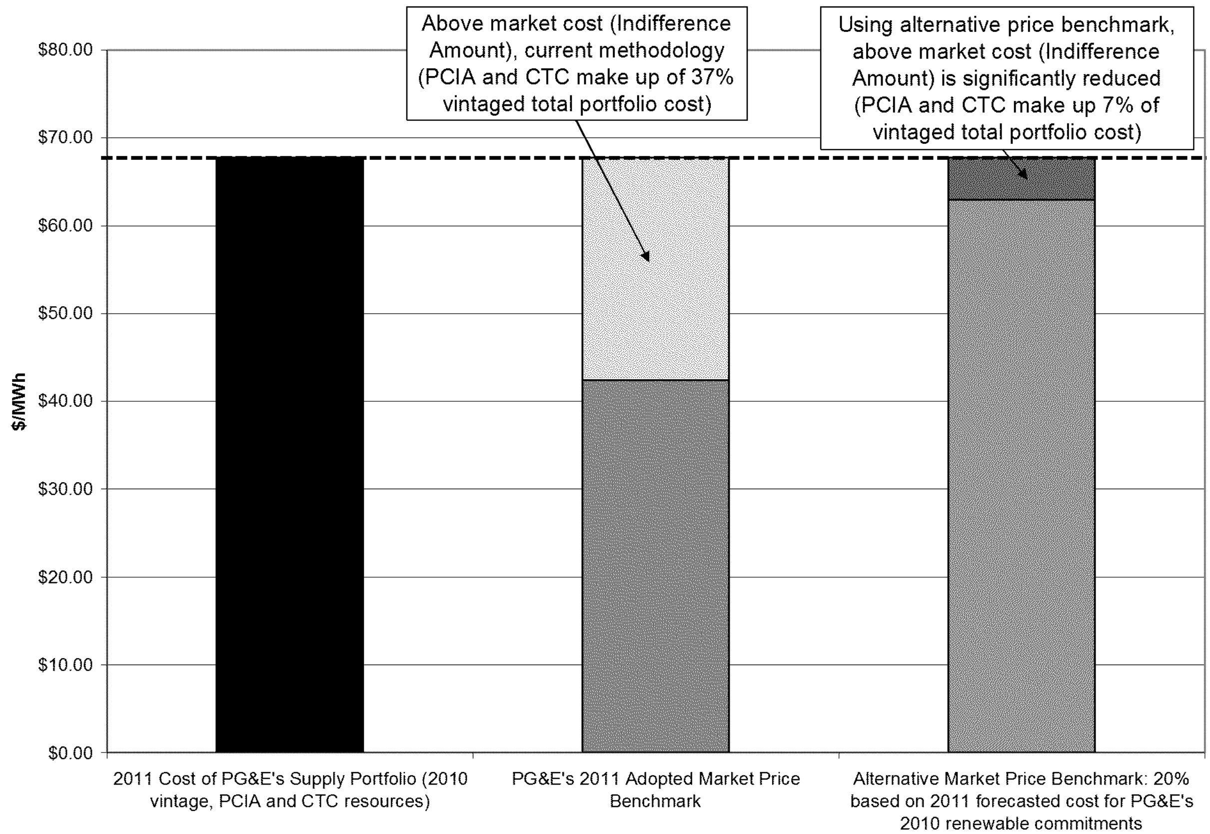
Q. Please compare resulting Indifference Amounts (the PCIA and CTC) for PG&E for 2011 using the Green Benchmark and the approach you describe above and using the current methodology.

A. As shown above, using a renewable supply benchmark of $145/MWh for 20% of the supply portfolio results in a Market Price Benchmark of $63/MWh for PG&E. As shown in PG&E's November 2010 update to its 2011 ERRA Forecast application, the forecasted cost of the Total Portfolio (2010 and 2011 vintages) is $68/MWh. Using the current Market Price Benchmark of $42/MWh results in an above-market cost (the Indifference Amount) for the portfolio of $25/MWh (37% of Total Portfolio Costs), while using a more reasonable Market Price Benchmark of $63/MWh results in an above-market cost of only $5/MWh (7% of Total Portfolio Costs). (Total Portfolio Costs are "breakeven"

[7] Using PG&E's 2011 MPB the calculation is $42.42/MWh x 0.80 + $145/MWh x 0.20 = $63/MWh; using SCE's 2011 MPB the calculation is $44.51/MWh x 0.80 + $145/MWh x 0.20 = $65/MWh.

using a renewable benchmark of $169/MWh.) This comparison is shown graphically in the chart below. In terms of rates (spreading the Indifference Amount over all responsible load), the PCIA for 2010/2011 vintages would fall from a charge of $0.016/kWh to a charge of $0.001/kWh, a reduction of more than 90%. The CTC would fall from a charge of 0.007/kWh to a charge of $0.003/kWh, a reduction of nearly 60%.

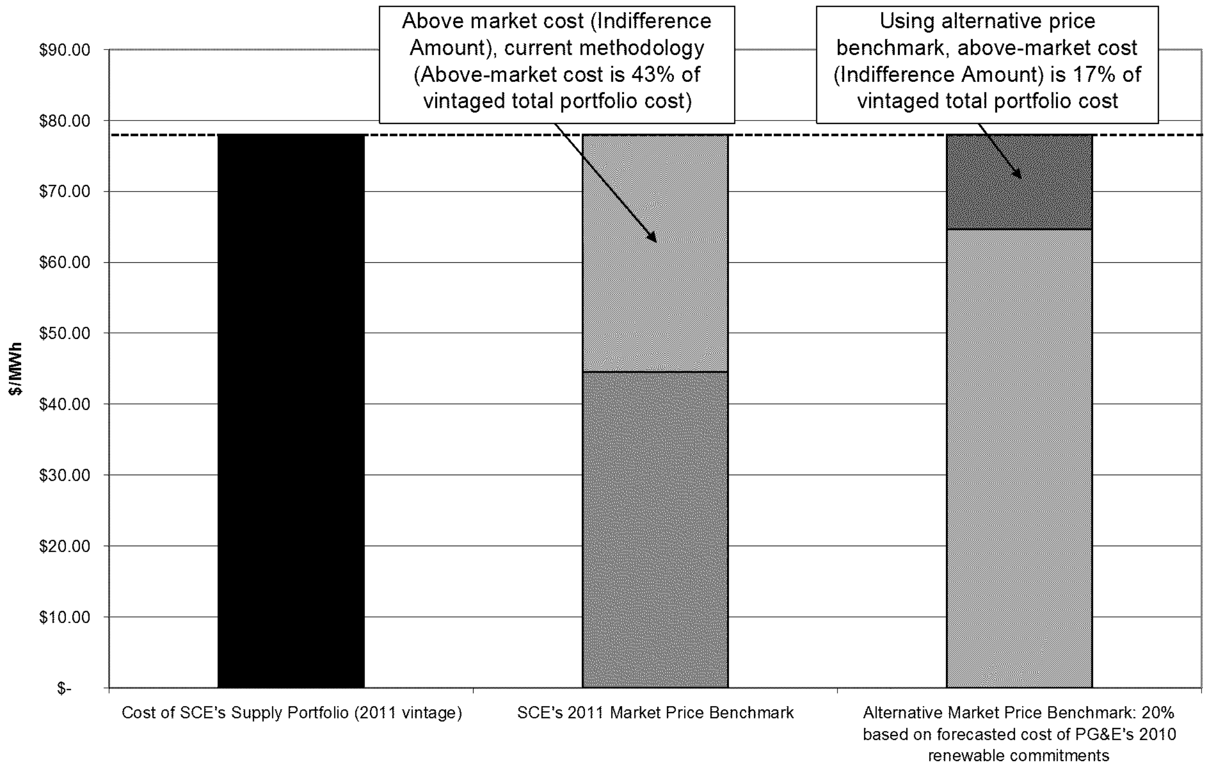
Reduction in Above-Market Costs and Indifference Amount (the PCIA and CTC) Using Renewable Benchmark of $145/MWh (PG&E, 2011)



Q. Do you have similar results for SCE?

A. Yes. Results for SCE, using the same renewable pri ce of $145/MWh, are shown in the chart below, and are very similar to the results for PG&E. Using the current methodology, the Indifference Amount (above-market cost) makes up 43% of SCE's Total Portfolio Costs. Using the alternative approach, the Indifference Amount (above-market cost) drops to 17% of Total Portfolio Costs, a reduction of 60% in the above-market cost, Indifference Amount, and resulting PCIA/CTC.

Reduction in Above-Market Cost and Indifference Amount (the PCIA and CTC) Using Renewable Benchmark of $145/MWh (SCE, 2011)



Q. But that calculation assumes that an IOU can sell renewable supplies at the same price at which it recently purchased renewable supplies. If an IOU loses load due to CCA enrollment or other load transfers to ESPs or POUs, won't the IOU have to dump power at bargain prices that may not reflect their full value?

A. No. First, Departing Customers reduce the IOUs' procurement requirements to meet bundled customer load growth and to meet RPS requirements for remaining bundled customers. As load departs, the IOUs can retain RPS resources that are freed up and use them to meet their RPS requirements, or they can back off their most expensive on-going renewable procurements. Second, to the extent the IOUs are behind on meeting their RPS targets, there will continue to be a strong demand for RPS-eligible supplies. Third, over the mid and long term, the IOUs can plan for load departure that has occurred and will occur, and can adjust their portfolio and new procurements to minimize costs and maximize value. There is no reason to value an IOU's renewable supplies as if they could only be sold at "fire-sale" prices.

H. UNDULY HIGH PCIA AND CTC RATES HAVE A SIGNIFICANT ADVERSE IMPACT ON ALTERNATE ENERGY SUPPLIERS AND THEIR CUSTOMERS

Q. How do PG&E's and SCE's vintaged total portfolio costs compare to their value based on the Market Price Benchmarks for each of them for 2011?

A. As shown in the tables below, the cost of the IOUs' supply portfolios is well above the respective Market Price Benchmarks using the current methodology. For example, for PG&E, forecasted above-market costs for 2011 for the total portfolio of supplies assigned to bundled customers and departing customers of vintage 2010/2011 are forecasted to be $1.7 billion, 37% of the total cost of those resources. [8]

PG&E Forecasted Portfolio Costs and Volumes, 2011			CTC Resources	PCIA Resources	All Resources assigned to 2011/2010 vintage
GWh at customer meter		GWh	15,604	52,978	68,582
Forecasted cost, 2011		$ millions	$ 1,208	$ 3,438	$ 4,647
Value based on Market Price Benchmark ($	$42.42	$ millions	$ 662	$ 2,247	$ 2,909
Above market cost based on Market Price Benchmark		$ millions	$ 547	$ 1,191	$ 1,738
Above market cost as a percent of total costs			45%	35%	37%
Portfolio forecasted cost at customer meter		$/MWh	$ 77.44	$ 64.90	$ 67.75

For SCE, the results are similar. For the total portfolio of resources assigned to bundled customers and departing customers of vintage 2011, SCE's above-market costs are forecasted to be $2.5 billion, 43% of the total cost of those resources.

SCE Forecasted Portfolio Costs and Volumes, 2011			All Resources assigned to 2011 vintage
GWh at customer meter		GWh	74,321
Forecasted cost, 2011		$ millions	$ 5,796
Value based on Market Price Benchmark	$44.51	$ millions	$ 3,308
Above market cost based on Market Price Benchmark		$ millions	$ 2,488
Above market cost as a percent of total costs			43%
Portfolio forecasted cost at customer meter		$/MWh	$ 77.98

Q. What is the financial impact of the resulting PCIA and CTC rates on Departing Customers?

[8] These costs do not include overcollections forecasted to accrue during 2010.

A. As shown in our testimony above, the distortion in the current method is significant. For example, for PG&E, including the value of renewables in the Market Price Benchmark could reduce the PCIA for 2010/2011 vintages from a charge of $0.016/kWh to nearly zero. Note that further adjustments to fully value all supply portfolio attributes, such as load shape and CAISO costs, have not been included in this comparison, and could likely result in a PCIA credit to offset CTC. Using the same methodology for CTC, PG&E's 2011 CTC would be reduced from $0.007/kWh to $0.003/kWh.

At current 2011 rates of $0.016/kWh for PCIA and $0.007/kWh for CTC for PG&E's 2010/2011 vintage customers, $0.024/kWh represents 28% of PG&E's average cost of generation (where the cost of generation includes all generation costs, including the CTC component of generation costs), while more reasonable PCIA and CTC costs are significantly lower, estimated here to be only 5% of PG&E's cost of generation.[9] This unfair cost burden creates a significant competitive disadvantage for alternative energy suppliers. This means that from the outset, before making a single purchase to meet the needs of their customers, alternative energy suppliers must first offset an artificial price differential of 23% ($0.019/kWh) in order to offer a competitively-priced product.

These inflated CTC and PCIA rates impose an artificial and unfair economic barrier to the success of CCA, Direct Access and other alternative supply programs and to the expansion of the renewable energy purchase opportunities of such programs.

III. RECOMMENDED CHANGES TO THE MARKET BENCHMARK CALCULATION

A. SUMMARY

Q: Please describe in detail how the current Market Price Benchmark is determined.

A: As summarized above, the MPB is based on a one-year forward price for power. The current Indifference Amount methodology utilizing the MPB was first established in

[9] Here, PG&E's generation costs, PCIA and CTC are based on rates as reported in PG&E's November 2010 update to its 2011 ERRA Forecast application, showing a system average generation rate for bundled customers of $0.07815/kWh (excluding CTC). On January 1, 2011, PG&E's system average generation rate fell to $0.06690/kWh (excluding CTC), as reported in PG&E's Advice Letter 3727-E-A, and the PCIA and CTC rates increased slightly, further increasing the price differentials cited here.

D.06-07-030 and refined in D.07-01-030.[10] As described above, the MPB is based on a one-year forward price for power. More specifically, mathematically, the MPB from these decisions equals:

MPB = (Weighted average futures quotes in October + Capacity/Resource Adequacy Adder) * (1+ line losses)[11]

Per D.07-01-030, the "weighted average futures quotes in October" refers to weighting October on-peak and off-peak futures quotes for the following calendar year by the number of on-peak and off-peak hours.

Q: Earlier in this testimony, the Joint Parties have pointed out a number of problems with the current Market Price Benchmark. What reforms do the Joint Parties recommend?

A: The Joint Parties make the following recommendations:

1. <u>Reflect in the Market Price Benchmark the value of renewable resources</u>. Rather than using the "weighted average futures quotes in October" as the primary indicator of market prices, the Joint Parties recommend using a benchmark that reflects the weighted average of standard, commodity power (as reflected in the futures quotes) to reflect the market value of non-RPS-compliant supplies, and a Green Benchmark to reflect the market price of RPS-compliant supplies.
2. <u>Reflect in the Market Price Benchmark the load shape of the supply portfolio</u>. The commodity power portion of the benchmark would be shaped in the manner described in Section III.C of this testimony.
3. <u>More accurately reflect in the Market Price Benchmark the value of capacity.</u> Rather than a simple dollar per megawatt-hour value, the capacity adder would be calculated based upon the CAISO's "capacity procurement mechanism" ("ICPM") price and the net qualifying capacity ("NQC") for the portfolio of that IOU. This would be done on a vintaged basis.

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[10] D.06-07-030 refers to the indifference <u>rate</u> methodology as well as the Indifference Amount. SCE and SDG&E calculate a specific indifference rate by dividing the Indifference Amount by the appropriate volumetric denominator. PG&E chooses to not perform this particular calculation and thus only presents an "Indifference Amount."

[11] Formula from Appendix 1 to D.06-07-030, reflecting the on-peak / off-peak weighed averages forward strip from D.07-01-030, Ordering Paragraph 1(c) and 2(e).

4. More accurately account for avoidable costs related to the CAISO. The CAISO charges can be addressed by removing them from the Total Portfolio Cost and by including a basis adjustment to the commodity power price to reflect the actual point of delivery at the appropriate Load Aggregation Point.

Mathematically this would equal:

MPB = ([Weighted Average of the shaped futures quotes in October and Green Benchmark, based on RPS content] + Basis Adjustment + Capacity Adder) * (1+ line losses)

Each of these terms are defined and explained in the following sections.

B. WEIGHTING THE GREEN BENCHMARK AND THE COMMODITY POWER BENCHMARK

Q: Please describe the Joint Parties' proposal for weighting the Commodity Power and Green Benchmarks.

A: The weighting of the two benchmarks would be based upon the RPS-compliant green content of the power included in the vintage-specific Total Portfolio Cost, including, as is the current case, all the costs associated with the portfolio of resources whose cost are included in the CTC revenue requirement. For example, if the power associated with the renewable energy in the resources underlying the Total Portfolio Cost represented 18% of the total forecasted energy deliveries, then the MPB would equal 0.82 times the shaped commodity power price plus 0.18 times the Green Benchmark (plus appropriate capacity, shaping, and loss factors and adjustments).

Q: Would a single set of weights be used for all vintages?

A: No. Since the resources underlying the Total Portfolio vary by vintage, so would the weighting.

Q: What theoretically should the Green Benchmark be?

A: Like the current MPB approach for commodity energy, the Green Benchmark should ideally reflect the forward-looking market cost of RPS-compliant energy.

Q: Does a market for RPS-compliant energy exist?

A: No. In the future, the Joint Parties expect there to be an open, transparent and liquid market for renewable power that will provide price transparency for renewable energy used for RPS compliance. Such a market does not exist. Because such a market does not exist, the only choice that the Commission has to implement a Green Benchmark is to use a reasonable proxy.

Q. Doesn't Decision 11-01-025 create such a market?

A: The Joint Parties are skeptical that the market for the so-called tradable renewable energy credits ("TRECs") that may arise out of D.11-01-025 would be appropriate for use in calculating the MPB. First, that decision places significant restrictions on the use of TRECs, which could result in prices that are not fully reflective of RPS-compliant energy. Second, a number of parties active in that rulemaking proceeding have expressed a variety of objections and concerns to that decision. Given these two overarching uncertainties, we cannot currently recommend pointing to the D.11-01-025 TRECs as a future option for use in setting the Green Benchmark.

Q: What criteria should be used to evaluate a proxy to be used as the Green Benchmark?

A: The proxy would ideally (1) reflect current prices for RPS-compliant renewable energy, (2) be verifiable, (3) be reasonably calculated in the context of a utility ERRA application.

Q: Why is reflecting current prices for RPS-compliant renewable energy important for a proxy?

A: First, the MBP, by design reflects a market price, so it will vary with changing market conditions; any Green Benchmark should be consistent with this. Second, the renewable power industry is not technologically mature. Innovations continue to occur. These innovations affect the cost of producing renewable power, which in time should be reflected in the market cost of renewable power. If a robust market for RPS-compliant renewable power existed, the pricing would also reflect the impact of the cost of producing renewable power. As such, any proxy should rely upon the cost of renewables that are just beginning to go into service (as they would likely be setting the market price were a market to exist).

Q: Why should the Green Benchmark be verifiable?

A: The value of the Green Benchmark will affect the Indifference Amounts (the PCIA and CTC) paid by virtually all Departing Customers. Furthermore, even though they do not pay PCIA explicitly except through their bundled generation rate, bundled customers have an interest in having a fair Green Benchmark, as it is necessary to maintain bundled customer indifference. Thus, virtually all IOU customers have a material interest in ensuring that the inputs to the Indifference Amount are being calculated fairly, accurately, and transparently.

Q: Why is it important that the Green Benchmark be reasonably calculated in the context of the utility ERRA forecast applications?

A: Decisions 03-07-030 and 06-07-030 specify that the CTC and PCIA be calculated in each IOU's ERRA forecast application and the Joint Parties find no reason to change this. Each utility's ERRA Forecast proceeding is an effective, existing mechanism to accomplish this goal, since it is utility-specific, is conducted annually, and already includes collection of the data necessary for the current and the Joint Parties' proposed methodology. As such, whatever the Green Benchmark is, it must be able to be used in the context of the ERRA application.

Q: What do the Joint Parties propose to be used for the Green Benchmark?

A: The Joint Parties propose that the Green Benchmark in *year n* equal the average of the IOUs' RPS-compliant generation costs in year *n* for generators that began delivering in year *n-1* and are projected to begin delivery in year *n*.

Q: How would this work in practice?

A: This is best shown in an example. Consider what the Green Benchmark would have been had it been in place for determining 2011 Indifference Amounts, the PCIA and CTC:

1. Each utility would identify all RPS-compliant resources that began delivery in year 2010 and those projected in their ERRA forecast applications to begin delivery in 2011. This would include both contracts and IOU-owned resources.

2. The IOUs would identify the projected costs of energy produced by each of these resources in 2011.

3. IOUs would then provide these data (costs in dollars and volumes in MWh) to the Energy Division.

4. The Energy Division would then calculate the average cost of power from these resources in 2011 by summing up all the costs from all three IOUs and dividing by the sum of all the MWHs from all three IOUs. This could be calculated or verified by trusted non-market participant(s).

5. This average value would be the Green Benchmark for all three IOUs.

Q: Why does the Joint Parties' recommended Green Benchmark rely on IOU data?

A: There are two reasons for this. First, the IOUs are by far the largest entities in California needing to acquire RPS-compliant resources. In 2011, they are projected to represent 88% of the load subject to the 20% RPS compliance target.[12] As such, they would naturally be the counterparties to the vast majority of renewable transactions going on in the state. Second, and more pragmatically, the IOU data are readily available, as it would be included in the ERRA forecast applications anyway. This proposal simply lifts a few lines of data from each application. Thus, the IOU data would offer a reasonable and implementable proxy for the market price of green power appropriate for use in the Green Benchmark calculation. Moreover, until the IOUs achieve compliance with the full 33% RPS requirement in 2020, they can retain and bank any "excess" RPS compliant resources "freed up" by Departing Customers to meet the upcoming incremental requirements in subsequent years.

Q: Why does the Joint Parties' recommended Green Benchmark use two years of data?

A: New generating resources are not added in a smooth fashion. A large resource may come online in one year, and a few smaller ones the next. As such, by using two years of data the Green Benchmark is not unduly influenced by a single larger project, while still maintaining the "recent" criterion.

Q: Why does the Joint Parties' recommended Green Benchmark use a single benchmark across all three IOUs?

A: There are two reasons for this recommendation. First, as mentioned, new resources are not added smoothly, and thus the same averaging rationale behind the use of two years of data supports the recommendation of averaging across all three IOUs. Second, averaging across all three IOUs addresses potential confidentially issues that could arise by relying upon a single utility's data.

Q: How does the Joint Parties' recommended Green Benchmark reflect current prices for RPS-compliant renewable power?

A: By relying upon resources that are either in their first or second year of power production, the costs associated with only the most recent resources are included.

[12] Calculated from "Department of Water Resources Proposed Revision to the Determination of Revenue Requirement For the Period January 1, 2011 through December 31, 2011." October 18, 2010. Page 13, table D-1.

Q. How does the Joint Parties' recommended Green Benchmark account for the fact that costs for renewable resources vary widely according to technology, location, and many other factors?

A. Our proposal explicitly accounts for this by using the mix of renewables that the IOUs are actually bringing on line in the current period.

Q: Is the Joint Parties' recommended Green Benchmark verifiable?

A: Because it relies upon timely IOU filings at the CPUC, the data are verifiable. Nonetheless, just as the futures-strip portion of the current MPB is calculated by a trusted third party, the Commission's Energy Division, the Joint Parties recommended Green Benchmark would also be calculated by the Energy Division. Furthermore, any party would have the right to hire a non-market participant to review the calculation. The review would be subject to all appropriate Commission confidentiality rules and paid for by the party desiring verification.

Q: Can the Joint Parties' recommended Green Benchmark be calculated in the context of the utility ERRA forecast applications?

A: Yes. The Benchmark could be calculated by the Energy Division in the same timeframe as the current MBP. This would allow sufficient time so that data from the last IOU that files its ERRA forecast, SD&GE on October 1 of each year, would be available to calculate the first IOU's (PG&E's) MPB in time for the rate changes to be included in the decision approving its ERRA forecast application.

Q: Do the Joint Parties propose that this Green Benchmark be used indefinitely?

A: No. As was identified in the first part of this section, the Joint Parties expect there may eventually be an open, transparent and liquid market for RPS compliant renewable energy or renewable attributes. When such a market develops, the Green Benchmark should be based on the market value of the renewable attribute from that market. We do not know when a sufficiently suitable, open, liquid, and transparent market for renewables will develop or the details of how such market will operate. Thus, the use of prices from such a market to adjust the Market Price Benchmark is beyond the scope of this testimony.

Q: In the December 13th Workshop, SCE and PG&E presented a joint proposal that included a proposed Green Benchmark. The presentation characterized the

proposal as "U.S. Dept. of Energy's survey of reported contract premiums for renewable energy in the Western U.S."[13] Did SCE or PG&E provide this survey?

A: When requested, an SCE representative provided an internet URL web address.[14] However, the website is not a survey of contract premiums for renewable energy but rather a sampling of utility green retail pricing programs.

For example, the referenced table shows that the Anaheim Public Utilities offers a "Green Power for the Grid" program in which Anaheim residents and businesses can pay an additional 2¢ per kWh that "goes toward purchasing more of the green energy for the Anaheim Power Grid."[15] The program description says that "The contribution will be added to your utility bill and will be invested in green, renewable power resources for our community."[16] The 2¢/kwh does not explicitly pay for an additional kilowatt hour of green power, let alone represent the incremental cost of RPS-compliant power, but is merely "invested" in green power sources.

If a survey of actual renewable wholesale contract premiums existed, and those premiums were specific and limited to resources compliant with California's RPS requirements, it might provide a useful input into developing a Green Benchmark. However, the table to which SCE and PG&E referred in the Workshop clearly is not such a survey and cannot reasonably be used to develop a Green Benchmark.

Q: You note that the Green Benchmark must, out of necessity, be a proxy for the cost of renewable power. Is there a simpler alternative than creating a Green Benchmark?

A: Yes. RPS-compliant resources can be removed completely from the Indifference Amount calculation. This is, in fact, the preferred option for some of the Joint Parties. Given the flexible mechanisms in place for RPS compliance, renewable generation is never "stranded" due to the departure of load. If in a year an LSE has produced or procured more renewable power that it needs to meet that year's RPS obligations, that incremental

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13 "Joint SCE/PG&E Proposed Modification of Indifference Amount Calculation" DA OIR Phase III Workshop, December 14, 2010, page 4.

14 http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=1

15 http://www.anaheim.net/utilities/adv_svc_prog/green_power/res_form.htm Accessed 1-14-11.

16 http://www.anaheim.net/utilities/adv_svc_prog/green_power/GrnPwrPGM.pdf Accessed 1-14-11.

amount can be banked for future use (or be used to meet prior years' deficits). Second, CCAs and ESPs must acquire the same amount of RPS-compliant renewable power as the investor-owned utilities and the cost of this compliance is borne by their customers. As such, including the costs and volumes of RPS-compliant power in the PCIA and CTC effectively results in these Departing Customers paying not only for the renewable content of the power they consume but also for a fraction of the renewable power consumed by bundled customers.

C. PROPOSAL OF THE JOINT PARTIES TO REFLECT THE MARKET VALUE OF THE PORTFOLIO DELIVERY PROFILE

Q. How should the Market Price Benchmark be adjusted to reflect to market value of the delivery profile of the IOU supply portfolio?

A. The MPB should be adjusted so that it comprises a shaped energy price as opposed to the existing methodology which calculates a flat or baseload energy price as the energy component. The current MPB is based on an implicit assumption that the IOU supply portfolio serves a flatter load profile than it actually does and therefore creates an artificially low market value and artificially high Indifference Amount, and in turn, artificially high PCIA and CTC. Because the IOU supply portfolio is constructed to serve the load of bundled service customers as that load varies from hour-to-hour, the load shape of bundled service customers should be used in valuing the IOU supply portfolio. Using the total bundled load profile to value the IOU supply portfolio is consistent with inclusion of the Total Portfolio Costs in the calculation of Indifference Amounts, PCIA and CTC.

If the utility load profile were flat, it would be appropriate to use a baseload price in the MPB calculation. However, the utility load profile is not flat. Rather, most customers tend to use more energy during the daytime peak hours than they do during the nighttime off-peak hours. A different and more costly mix of resources is necessary to serve a peakier load than a flat load, as such a portfolio requires proportionately more intermediate and peaking resources that tend to have higher operating costs than do baseload resources. Because the IOU supply portfolio includes costs to meet these load shape requirements, unless the MPB appropriately values the delivery profile of the supply portfolio, customers paying the PCIA and CTC will be charged more than necessary to preserve bundled customer indifference.

Q. Would using a shaped energy price require a completely new methodology for establishing the MPB?

A. The shaped energy price can be calculated with a relatively simple modification to the current MPB calculation. Under the current methodology, the forward prices for peak energy and for off-peak energy are used to calculate a forward baseload energy price. This is accomplished by calculating a weighted average of the peak and off-peak forward energy prices, using the number of peak and off-peak hours in the year, respectively, as the weighting factors. The current calculation is shown in the following illustrative example:

Period [Col. 1]	**Price ($/MWh) [Col. 2]**	**Hours [Col. 3]**	**Weighting Factor [Col. 4]**
On-peak	$40.00	5,008	0.572
Off-peak	$28.00	3,752	0.428
Baseload Price	$34.86		

In order to calculate a shaped energy price, the weighting factors should be calculated based on the annual forecast of energy sales to bundled customers during the peak and off-peak periods of the year. An illustrative calculation of a shaped energy price is shown in the following example. The number of peak and off-peak hours from column 3 has been replaced with the forecast of sales to bundled customers during the peak and off-peak periods, resulting in an average price more heavily weighted toward the on-peak period. The actual shaping factors should be based on the hourly load profile used by the utility for its sales and cost forecasts provided in the annual ERRA proceeding.

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

Q. Would the shaped energy price vary by vintage?

A. No. An advantage of using the utility's bundled load profile from its current ERRA sales forecast for the weighting factors is that the shaped energy price for "brown" power would be the same for all PCIA vintages and for the CTC portfolio. Attempting to use different load profiles to calculate a shaped energy price for different vintages would likely yield very little change in the results and add unnecessary complexity to the Indifference Amount, PCIA and CTC calculations.

Q. Are the inputs required for calculating the shaped energy price publicly available?

A. The utility's bundled hourly load profile is used to derive the utility's fuel and purchase power expense forecast presented in the annual ERRA proceeding. This is the same proceeding in which the MPB, Indifference Amounts, PCIA and CTC are set for the coming year, so data availability should not be an impediment to using the bundled load shape in these calculations. However, much of the data in the ERRA proceeding are redacted due to utility assertions of confidentiality. If the utilities are concerned about confidentiality of the hourly load profile data, the Commission's Energy Division or another third party could validate the load profile weighting calculation. The actual weighting factors (annual peak and off-peak load percentages) that would be used to calculate the shaped energy price are highly aggregated and should not raise any legitimate confidentiality concerns.

Further, the utilities publish historical hourly class load profiles that could be used to derive a load profile adjustment for the MPB, and which would not involve use of any confidential data. While this could be an acceptable alternative to using the bundled load profile from the ERRA, it would require an additional set of calculations and is therefore not the preferred approach.

<u>D. PROPOSAL OF THE JOINT PARTIES FOR MPB ADJUSTMENTS TO REFLECT THE VALUE OF CAPACITY</u>

Q. Do you recommend any changes to the way that capacity is reflected in the market price benchmark?

A. Yes. The current market price benchmark includes capacity adders that were the result of a settlement among parties in 2006, when the resource adequacy program was just getting underway. These proxy capacity values should be refined with more current information. The utilities joint workshop proposal would establish the capacity value of the utility portfolio based on the total "Net Qualifying Capacity" ("NQC") of all generation resources (utility owned and power purchases) in the utility portfolio and the price for capacity established by the CAISO in the Interim Capacity Procurement Mechanism

("ICPM"), as that price is modified and approved by FERC from time to time.[17] The capacity value would vary for each portfolio vintage, as the NQC would reflect the specific resources included in each vintage.

The Joint Parties support using the NQC of each vintaged supply portfolio and the ICPM or its successor to value the capacity of the portfolio. The supply portfolio NQC should be the sum of the individual NQC of all resources included in the cost of each vintaged supply portfolio (Total Portfolio Cost), as these vary by vintage, and these data should be made available for verification by the Energy Division and non-market participants as designated by other parties. The ICPM is a reasonable measure of short-term capacity prices as it is the price paid by the CAISO to procure capacity when this becomes necessary due to failure by a load serving entity to meet its resource adequacy obligation or when system conditions necessitate procurement of additional capacity. Further, the ICPM has the benefit of being publicly available.

Q. Should the capacity value be a static value, established based on the current ICPM?

A. No. The capacity value should be updated annually, when the MPB is updated, to reflect changes in the CAISO's ICPM price that are approved by FERC; otherwise there is the risk that the value becomes stale over time and deviates from then-current market values, which would distort the MPB. The ICPM is expected to transition to a new backstop capacity mechanism known as the Capacity Procurement Mechanism (CPM) after March 31, 2011. The ICPM price would be used to establish the PCIA and CTC for 2011 when a decision in this proceeding is issued. If the new CPM price goes into effect during 2011 as planned, it should be used for the 2012 PCIA and CTC.

E. PROPOSAL OF THE JOINT PARTIES TO ACCURATELY ACCOUNT FOR CAISO COSTS

Q. How should costs charged by the CAISO be accounted for in the determination of PCIA and CTC?

A. Certain costs that are charged to the utilities by the CAISO are dependent upon the amount of load for which the utilities provide generation services. These load-based CAISO charges are variable costs that are directly avoided when a non-utility provider,

[17] See presentation #6 attached to the Workshop Report of the Joint Parties, January 14, 2011.

such as an ESP or a CCA, provides generation services to the customer. The non-utility provider pays these costs directly to the CAISO for the customer load for which it provides generation services.

Currently the utilities include forecasted CAISO costs in the ERRA proceeding for recovery in generation rates, and these costs are also included in the Total Portfolio Cost for purposes of calculating the PCIA and CTC. The current methodology inappropriately treats avoidable CAISO costs as if they are unavoidable, above market utility generation-related costs. The result is that Departing Customers pay for the CAISO costs associated with their load through their non-utility provider and also pay a share of bundled service customers' CAISO costs through the PCIA. The load-based costs of CAISO services should be removed from the utility's Total Portfolio Cost for purposes of calculating the PCIA and CTC so that customers paying the PCIA and CTC don't pay more than necessary to maintain bundled customer indifference.

Q. What specific load-based CAISO costs should be removed from the vintaged Total Portfolio costs used to determine PCIA and CTC?

A. All CAISO charges that are allocated to the utility's scheduling portfolio on the basis of load should be eliminated from Total Portfolio Costs. These costs include various charges for grid management services, ancillary services, congestion, unaccounted for energy, neutrality and other load-based fees. Exhibit A delineates the appropriate CAISO charges by individual charge code designation.

Q. Would removing load-based CAISO costs from the Total Portfolio Cost completely eliminate the double-charging of CAISO costs to Departing Customers?

A. As long as the utilities provide a complete and accurate forecast of load-based CAISO costs in their ERRA proceedings, then removing these costs from the Total Portfolio Costs used to calculate the PCIA and CTC would eliminate the double-charging problem described above. However, in past ERRA proceedings there has been insufficient information provided in the utility filings to determine whether the IOU's forecasts of CAISO costs accurately capture all relevant CAISO costs. The Joint Parties have a significant concern that without additional information that would enable third party verification of the reasonableness of the utilities' CAISO cost forecasts, removal of the utilities' forecast load-based CAISO costs may not be a complete solution to this problem.

Q. Is there reason to believe that some CAISO costs are not included in the utility CAISO cost forecasts?

A. It is not clear whether the utilities' CAISO cost forecasts in ERRA include any CAISO costs associated with transmission congestion. These costs should be excluded from vintaged Total Portfolio Costs, because these costs are not reflected in the MPB. Based on statements made by SCE at the workshop on January 4th, 2011, the Joint Parties understand that SCE bases its ERRA cost forecasts on projected prices at the SP15 trading hub, with no accounting for congestion between the SP15 trading hub and the actual point of delivery at the SCE Load Aggregation Point. If that is the case there would be a systematic under-collection of SCE's CAISO costs that would ultimately be recovered in the subsequent year through the ERRA balancing account and inappropriately charged to Departing Customers through the PCIA and CTC. PG&E indicated that it includes congestion costs in its CAISO cost forecast in ERRA, but provided no further details. Additional information regarding how the various CAISO costs are recovered in rates is required from each of the utilities to validate that removing the utilities' forecast CAISO load-based costs from the Total Portfolio Cost will ensure that all appropriate CAISO costs would be eliminated from the PCIA and CTC.

Q. If removing the utility forecast of CAISO load-based costs does not address the removal of all congestion costs from the PCIA and CTC, what further adjustments would be necessary to preserve bundled customer indifference?

A. The market price benchmark should be adjusted so that it represents a market price at the actual delivery points for the utilities' vintaged supply portfolios. The actual delivery points are the Load Aggregation Points ("LAP") for PG&E, SCE and SDG&E, respectively. The current MPB, however, is defined at the trading hub – NP15 for PG&E and SP15 for SCE and SDG&E – and does not account for congestion costs between the trading hub and the LAP.

Q. Can congestion costs between the trading hub and the LAP be estimated?

A. Yes. The CAISO publishes hourly prices for all trading hubs and all LAPs. A reasonable adjustment for congestion costs between the trading hubs and LAPs can be made using historical CAISO data. The joint parties propose using CAISO pricing data for the most recent calendar year to derive a congestion or "basis" adder to the MPB for each of the three utility LAPs. The basis adder would simply be the difference between the day-ahead hourly LAP price for a particular utility and the day ahead hourly trading hub price, averaged over the year.

Q. Would the utilities' allocation of congestion revenue rights impact the CAISO cost forecast and, in turn, PCIA and CTC?

A. It is possible that the utility's holdings of congestion revenue rights would reduce the congestion charges it incurs from the CAISO. However, the existence of congestion revenue rights does not change the justification for ensuring that the MPB is reflective of the appropriate delivery point for the utility supply portfolio. If the utility has excess supply as a result of customers electing to take generation service from a non-utility provider, the utility's supply costs would be reduced based on the energy prices at the LAP and <u>not</u> based on prices at the trading hub, regardless of whether the utility has congestion revenue rights. The LAP price is the appropriate delivery point and should be the basis for the MPB.

Q. Under your proposal, what basis adders should apply for 2011?

A. The basis adders for 2011 would be based on CAISO data for 2010 and would equal $0.99 per MWh for PG&E, $0.82 per MWh for SCE and $0.72 for SDG&E. The average of the hourly day-ahead locational market prices at the three Load Aggregation Points and the two trading hubs are shown in the following table, based on data obtained from the CAISO's Open Access and Real Time Information System (OASIS):

Utility	LMP at Load Aggregation Point ($/MWh)	LMP at Trading Hub ($/MWh)	Basis Adjustment ($/MWh)
PG&E	36.77	35.78	0.99
SCE	36.17	35.35	0.82
SDG&E	36.07	35.35	.072

F. TREATMENT OF SHORT-TERM PURCHASES

Q. Should short term power purchases and sales be excluded from the Total Portfolio Cost and PCIA calculation?

A. There appears to be inconsistency among the utilities on how they are currently treating short term purchases and sales. PG&E reportedly excludes power purchase commitments of less than 12-month's duration from the total supply portfolio while SCE includes these costs. The utilities should be consistent in their treatment of short-term purchase costs in the PCIA. The Joint Parties require additional information to determine whether the PG&E approach or the SCE approach should be adopted.

G. THE SAME MARKET PRICE BENCHMARK SHOULD BE USED FOR INDIFFERENCE AMOUNTS, PCIA AND CTC

Q: Decision 05-12-45 specifies that the CTC be calculated in a manner similar to the Indifference Amount: "The total costs of the CTC resources are compared to the Market Price Benchmark times the generation from CTC resources."[18] Since this calculation relies upon the same MPB as the Indifference Amount, need the MPB in the CTC be updated, and if so, how?

A: Yes, the MPB going into the CTC revenue requirement calculation should be updated to be consistent with the updated MPB used to calculate vintaged Indifference Amounts. Specifically, the bundle of generation resources that are assigned for cost recovery to the CTC should be treated effectively as its own "vintaged" portfolio. To the extent that there are resources included in the CTC portfolio that are RPS-eligible, then the weighting between the standard futures quote and the Green Benchmark should be implemented. The MPB should be adjusted to reflect the market value of the portfolio delivery profile. The Capacity Adder should be based upon the NQC of the resources that make up the CTC generation portfolio. Adjustments should be made to accurately account for CAISO load-based charges, that is, as described above, CAISO load-based charges should not be included in the cost of the CTC portfolio, and a basis adder should be included in the MPB. The same line-loss factor that is used for the MPB should be used to determine Indifference Amounts. This way, the MPB for CTC will remain internally consistent with the methodology used for Indifference Amount calculation.

Q. Does that conclude your direct testimony?

A. Yes.

[18] See D.05-12-045, page 18.

Exhibit A

Load Related CAISO Charges

Charge Code	Description
550	FERC Fee Settlement Due Monthly
721	Intermittent Resources Net Deviation Allocation
752	Monthly Participating Intermittent Resources Export Energy Allocation
4501	GMC - Core Reliability Services Non-Coincident Peak
4505	GMC - Energy Transmission Services Net Energy Withdraw als
4506	GMC - Energy Transmission Services Deviations
4511	GMC - Forward Scheduling
4512	GMC - Forward Scheduling Inter-SC Trades
4534	GMC - Market Usage Ancillary Services
4536	GMC - Market Usage Uninstructed Energy
4537	GMC - Market Usage Forward Energy
4575	GMC - Settlements Metering and Client Relations
4999	Neutrality Adjustment
6090	Ancillary Service Upward Neutrality Allocation
6194	Spinning Reserve Obligation Settlement
6196	Spinning Reserve Neutrality Allocation
6294	Non-Spinning Reserve Obligation Settlement
6296	Non-Spinning Reserve Neutrality Allocation
6457	Declined Hourly Pre-Dispatch Penalty Allocation
6474	Real Time Unaccounted for Energy Settlement
6477	Real Time Imbalance Energy Offset
6480	Excess Cost Neutrality Allocation
6486	Real Time Excess Cost for Instructed Energy Allocation
6594	Regulation Up Obligation Settlement
6636	IFM Bid Cost Recovery Tier 1 Allocation
6678	Real Time Bid Cost Recovery Allocation
6694	Regulation Down Obligation Settlement
6696	Regulation Down Neutrality Allocation
6700	CRR Hourly Settlement
6774	Real Time Congestion Offset
6790	CRR Balancing Account
6791	CRRBA Accrued Interest Allocation
6806	Day Ahead Residual Unit Commitment (RUC) Tier 1 Allocat ion
6947	IFM Marginal Losses Surplus Credit Allocation
6977	Allocation of Transmission Loss Obligation Charge for Real Time Schedules Under Control Agreements
7989	Invoice Deviation Interest Distribution
8826	Monthly Resource Adequacy Standard Capacity Product MD Allocation
8827	Monthly NRSS Resource Adequacy Standard Capacity Product MD Allocation

Exhibit B

John Dalessi

John Dalessi
Principal

Dalessi Management Consulting LLC
3941 Park Drive, Suite 20-201
El Dorado Hills, CA 95762
Tel: 916.293.9730

john@dmcadvisors.com

Professional History

- Principal, Dalessi Management Consulting, LLC
- Director, Navigant Consulting, Inc
- Director – Business Development, Automated Power Exchange
- Manager – Tariff and Market Analysis, PG&E Energy Services
- Manager – Pricing & Analysis, Southern California Edison

Education

- M.A. – Economics, University of California, Santa Barbara
- B.A. – Economics, California State University, Long Beach

John Dalessi is Principal and founder of Dalessi Management Consulting LLC (DMC), which provides strategic advice and technical support to organizations active in the California energy market. Mr. Dalessi, has held senior leadership positions in the wholesale, retail and regulated sectors of the electric utility industry during his twenty-year career. Mr. Dalessi advises public agencies, generation project developers, and private investors on large, multi-million dollar infrastructure projects and energy programs. Prior to forming DMC, Mr. Dalessi held senior management positions at Navigant Consulting, Inc, the Automated Power Exchange, PG&E Energy Services, and Southern California Edison Company.

Professional Experience

» **Resource Planning and Procurement – 2009 – 2011** – Marin Energy Authority - Developed and administered competitive solicitations for power supply, renewable energy and data management services required for operations as a Community Choice Aggregator. Managed preparation of electric load forecasts and resource plans, program electric rates, program budgets and regulatory compliance activities.

» **Generation Development and Contract Support** – Confidential Client – Managed preparation of a successful offer into the Pacific Gas and Electric Company 2008 All Source Request For Offers. Managed the bid preparation process on behalf of the client, a large generation project developer, and prepared an extensive project description demonstrating the viability of the project's siting, pemitting and financing plans. Managed an internal team of technical experts and subcontractors to perform technical studies in support of the project relating to transmission system impact and interconnection requirements, natural gas supply and pipeline routing, and water supply. Led development of the project's permitting plan.

» **Organizational and Business Planning – 2006 – 2009** – Marin Energy Authority and San Joaquin Valley Power Authority - Assisted twenty-one local governments in Northern and Central California in the formation of joint powers agencies for provision of retail electric service. Work resulted in the formation of the San Joaquin Valley Power Authority in December of 2006 and the Marin Energy Authority in December of 2009. Authored the state's first Community Choice Aggregation Implementation Plan certified by the California Public Utilities Commission, detailing how the CCA program would be organized, operated and funded.

» **Open Access Same Time Information System (OASIS) 2006-2009** – Led implementation and provided ongoing project management for an OASIS for a publicly owned transmission provider. Negotiated transmission agreements with transmission customers, developed and administered transmission credit policy, and coordinated posting of Available Transfer Capability in accordance with the open access transmission tariff, business practices, and NERC mandatory reliability standards.

» **Load Aggregation Feasibility Analyses – 2003-2007** – Various California Cities and Counties - Represented the interests of nearly twenty local governments in the CPUC's implementation proceeding as it relates to exit fees, transactions costs, and provision of customer information to potential community choice aggregators. These communities represent over 2,000 MW of load currently served by the investor-owned utilities. Met with dozens of local governments throughout California to explain the benefits, risks and challenges associated with implementation of electric aggregation programs, beginning with the enactment of AB 117 in January 2002. Developed and performed detailed financial modeling for numerous local governments that are investigating electric aggregation and other municipal energy options. A particular area of focus has been how communities can cost-effectively meet or exceed the California Renewable Portfolio Standards. Also investigated opportunities for cities and counties to partner with water and irrigation districts to finance development of generation resources and provide operator services to the aggregation programs. Clients included the Counties of Los Angeles, Marin and San Diego, the Cities of Beverly Hills, West Hollywood, Oakland, Pleasanton, Berkeley, Vallejo, Emeryville, Richmond, the East Bay Municipal Utilities District, and the Kings River Conservation District.

Renewable Energy Resources – 2003-2007 – Local Government Commission, Sacramento – Modeled cost-effectiveness of procuring renewable energy through power purchase contracts, public agency resource ownership/financing, and purchase of renewable energy credits. Evaluated costs and operating characteristics of the renewable technologies most likely to be utilized to meet the California Renewable Portfolio Standard, including wind, solar, biomass, and geothermal resources. Quantified the operating impact of utilizing intermittent resources such as wind and solar and assessed options for firming/shaping these resources. Researched applicability of available subsidies, such as investment/production tax credits and public goods funds administered by the California Energy Commission, for municipal utilization of renewable resources to meet and exceed the minimum renewable portfolio requirements. Benchmarked renewable utilization against the renewable energy in the supply portfolios of PG&E, SCE, and SDG&E.

» **NERC Reliability Standards – 2006-2010** – Transmission Agency of Northern California – Conducted comprehensive assessment of applicable NERC reliability standards following passage of the Energy Policy Act of 2005. Conducted review of compliance, assessment of documentation and developed additional documentation to demonstrate compliance in preparation for mandatory self-certification and compliance audits.

» **Open Access Transmission Tariff Reform – 2006-2007** – Monitored OATT reform initiative at FERC culminating in issuance of Order 890. Assisted transmission provider in assessing changes necessary to its OATT for compliance with Order 890.

» **Distribution Utility Assessment – 2005-2006** – Presidio Trust – Assessed financial performance of distribution utility operations and identified performance improvement strategies. Evaluated opportunities for improving top line revenues, strategic partnering and asset divestiture.

» **Municipal Energy Options – 2003-2004** – City of Chula Vista - Assisted the City of Chula Vista in assessing feasibility of various options for city provision of electric and gas services to customers within the city. Constructed alternative electric supply portfolios and determined ancillary services and operations costs for each option. Developed financial models comparing revenues, costs, and opportunities for cost savings relative to continuing service from the host utilities.

» **California Independent System Operator – 2003** – Transmission Agency of Northern California, Sacramento - Represented the interests of the Transmission Agency of Northern California and Silicon Valley Power in the ISO's Market Redesign efforts. Participated in working groups and provided comments on various proposals and tariff amendments to the ISO and the Federal Energy Regulatory Commission.

» **Federal Energy Regulatory Commission – 2003** – Silicon Valley Power, Santa Clara - Provided litigation support to Silicon Valley Power in a dispute over PG&E's attempt to impose scheduling coordinator costs through Silicon Valley Power's interconnection agreement with PG&E.

» **Transmission Pricing – 2003** – Transmission Agency of Northern California, Sacramento- Analyzed FERC's proposed pricing incentives for transmission owners to expand the transmission grid and join Regional Transmission Organizations. Drafted comments for the Transmission Agency of Northern California.

» **Generator Interconnection Standards – 2002** – Transmission Agency of Northern California, Sacramento - Provided comments to FERC on behalf of the Transmission Agency of Northern California regarding FERC's proposed standard generator interconnection procedures and agreements. Advised client evaluating interconnection of a generator regarding policy on transmission credits for applicant funded network upgrades.

» **Demand Response – 2002 –** California Power Authority, Sacramento - Developed a five-year demand response program for the California Power Authority (CPA) that allows the State of California to use demand reserves to offset peaking capacity requirements. The program includes scheduling the demand reserves into the California ISO's ancillary services markets on an aggregated basis and real time monitoring of customer performance. The reserves can also be used as day-ahead call options dispatched on a localized basis to relieve transmission congestion. Proposed the concept to CPA and wrote the program design, including the metering and telemetry requirements for loads qualifying to participate in the ISO's ancillary services markets. Garnered input in program design from key stakeholders representing major customer groups, technology vendors, and market operators. Assessed market barriers to wide-scale demand response participation.

» **Strategic Planning Wholesale Market Services – 2000 – 2001 –** APX, Santa Clara - Prepared market and competitor analysis for wholesale power exchange and scheduling services in North America, Asia and Europe. Contributed to drafting the company strategic plan. Participated in negotiations with NYMEX involving a proposed joint venture to provide physical scheduling for electricity futures contracts that go to delivery. Helped re-focus company business strategy on profitable scheduling coordination and settlement services. Created North American sales and revenue forecast for corporate budgeting. Analyzed potential merger between APX and the California Power Exchange. Evaluated political, regulatory, and financial implications. Presented recommendations to corporate board of directors.

» **Competitive Retail Pricing – 1999-2000** – PG&E Energy Services, San Francisco - Structured commodity and risk management products for PG&E Energy Service's retail electric commodity customers. Drafted retail commodity electricity sales agreements. Developed models to assess competitive supply options in regions throughout the United States, considering default service utility tariffs and wholesale market conditions. Restructured power sales agreements to maximize the risk-adjusted value of the company's electric portfolio. Modeled utility ratemaking, revenue allocation, and rate design to evaluate impact of changes on value of retail portfolio. Analyzed time series data on California ISO charges to develop fixed price commodity rates unbundled ancillary services pass-through rates.

» **Rate Design –1999 –** Southern California Edison Company, Rosemead - Designed Southern California Edison's unbundled rates for generation, transmission, distribution, competition transition charges, and other nonbypassable charges. Developed rates based on marginal cost of service for customer classes and individual customers within classes, structured to eliminate inter-class and intra-class subsidies. Sponsored testimony on various revenue allocation, rate design, and ratemaking issues. Developed departing load charges for customers leaving the utility system through self-generation, municipalization, or other forms of distribution bypass. Developed methodology for calculating the bundled service energy charges and direct access credits based on SCE's cost of procuring electricity from the wholesale market. Structured rate incentives for non-firm (interruptible) customers based on the marginal costs of generation, transmission, and distribution capacity. Developed interruptible rate for wholesale transmission customers. Conducted bill impact analyses of rate changes using population billing data and sample load research data. Assisted in conducting customer survey to determine preferences for various rate structures and pricing options.

- » **Cost of Service –1999** – Southern California Edison Company, Rosemead - Calculated marginal cost of service for customer classes for use in SCE's revenue allocation and rate designs. Developed marginal cost based floor prices for special contract negotiations and flexible pricing options. Analyzed impacts of different marginal costing methods on utility rate structure and wrote position papers on marginal costing methods. Evaluated impacts of customers installing own distribution substations and migrating to high voltage service. Performed cost of service studies for subgroups of customers to determine justification for establishing new customer classes for ratemaking purposes. Conducted study that quantified the margin contribution for the largest 100 customers as well as by customer type (SIC code) using load research sample data.

- » **Sales and Revenue Forecasting - 1999**– Southern California Edison Company, Rosemead - Led development of SCE's models to forecast sales and revenues for various regulatory proceedings and internal budgeting purposes. Forecasted net revenues under alternative rate designs and ratemaking mechanisms to help develop company positions for regulatory proceedings.

Exhibit C

MARK E. FULMER

PROFESSIONAL EXPERIENCE

Principal
MRW & Associates, LLC
(1999 - Present)
Conducts economic and technical studies in support of clients involved in regulatory and legislative proceedings, power project development and end-user energy option assessment. Work includes analyses of rate design and ratemaking issues; pro forma analysis of cogeneration and distributed generation facilities; economic analysis of end-use energy-efficiency projects.

Project Engineer
Daniel, Mann, Johnson & Mendenhall
(1996 - 1999)
Acted as project manager and technical advisor on energy efficiency projects. Work included management of PG&E program to promote innovative energy efficient technologies for large electricity users. Coordinated the implementation of an intranet-based energy efficiency library. Directed technical and market analyses of small commercial and residential emerging technologies.

Associate
Tellus Institute
(1990-1996)
Advised public utility commissions in five states on electric and gas DSM, integrated resource planning and industry restructuring issues. Testified before the Hawaii PUC on behalf of a gas distribution utility concerning a competing electric utility's demand-side management plan. Submitted testimony on the rate design of a natural gas utility to the Pennsylvania Public Utilities Commission. Analyzed national energy policies for a set of non-governmental agencies, including critiquing the DOE's national energy forecasting model. Developed model to track greenhouse gas emission reductions resulting from state-level carbon taxes.

Research Assistant
Center for Energy and Environmental Studies, Princeton University
(1988-1990)
Researched the technical and economic viability of gas turbine cogeneration using biomass in the cane sugar and alcohol industries. First researcher to apply "pinch" analysis and a mixed-integer linear programming model to minimize energy use in cane sugar refineries and alcohol distilleries.

EDUCATION

M.S.E., Mechanical and Aerospace Engineering, Princeton University, 1991

B.S., Mechanical Engineering, University of California, Irvine, 1986

SELECTED PUBLICATIONS

"California: Crisis Over?" *Project Finance NewsWire*. Co-author Chadbourne & Parke LLP. October 2001.

"Market Transformation Effect Indicators for Government, Utilities, Retailers and Manufacturers," invited panelist in a roundtable discussion at the American Council for an Energy Efficient Economy (ACEEE) 1998 Summer Study.

"Evaluation of Food Processing Effluent Treatment Alternatives," paper presented at the American Chemical Society meeting, Las Vegas, Nevada. December 1997. Co-Author.

"A Social Cost Analysis of Alternative Fuels for Light Vehicles," in Energy Strategies for a Sustainable Transportation System, ACEEE, Washington, DC. 1995.

"Strategies for Reducing Energy Consumption in the Texas Transportation Sector," project for the Texas Sustainable Energy Development Council, Austin, Texas. June 1995. Co-author.

"Mistakes, Misconceptions, and Misnomers in DSM Cost-Effectiveness Analysis," peer reviewed paper at the ACEEE 1994 Summer Study. Principal author and presenter.

"The Role of Gas Heat Pumps in Electric DSM," presented at the 6th National Demand-Side Management Conference, Miami Beach, Florida. March 1993. Principal author and presenter.

"Applying an Integrated Energy/Environmental Framework to the Analysis of Alternative Transportation Fuels," invited paper at the European Council for an Energy Efficient Economy (ECEEE) 1993 Summer Study. Principal author.

"The Environmental Impacts of Demand-Side Management," Electric Power Research Institute report TR-101673. 1992. Co-author.

"Cogeneration Applications of Biomass Gasifier/Gas Turbine Technologies in the Cane Sugar and Alcohol Industries," proceedings, Energy and Environment in the 21st Century, MIT Press, Cambridge, Massachusetts. 1991. Co-author.

"A Technical and Economic Assessment of the Co-Production of Electricity and Alcohol From Sugar Cane," presented at the International Engineering Conference on Energy Conversion (IECEC-90), American Institute of Chemical Engineers, New York, NY. August 1990. Principal author and presenter.

Mark E. Fulmer
Prepared Testimony

1. Rhode Island Public Utilities Commission No. 2025
   Prepared Testimony on Behalf of Rhode Island Department of Public Utilites and Carriers (Commission Staff). Testimony addressed the costs, savings, and cost-effectiveness of the proposed demand-side management programs of Providence Gas Company. April 1993.

2. Pennsylvania Public Utility Commission R-943029
   Prepared Testimony on Behalf of the Pennsylvania Office of Consumer Advocate. Testimony reviewed 1307(f) filing of Columbia Gas of Pennsylvania on the impact of the proposed gas cost recovery mechanism on residential customers. May 1994.

3. Public Utilities Commission of the State of Hawaii No. 94-0206
   Prepared Testimony on Behalf of the Gas Company of Hawaii (Gasco). Testimony identification of Gasco's concerns regarding HECO's proposed DSM programs for competitive energy end-use markets. December 1994.

4. Arizona Corporation Commission No. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630. E01933A-02-0069, E-01933A-98-0471
   Rebuttal Testimony on behalf of Constellation NewEnergy, Inc. and Strategic Energy, L.L.C. Testimony addressed the future of the Arizona Independent System Administrator. July 28, 2002.

5. FERC Docket Nos. EL00-95-075 and EL00-98-063
   Affidavit on Behalf of Duke Energy Trading and Marketing LLC . March 20, 2003.

6. CPUC Rulemaking 01-10-024
   Prepared Testimony on Behalf of the Alliance for Retail Energy Markets. Testimony addressed the utility procurement plans with respect to resource adequacy. June 23, 2003

7. CPUC Rulemaking 01-10-024
   Rebuttal Testimony on Behalf of the Alliance for Retail Energy Markets. July 14, 2003.

8. Arizona Corporation Commission No. E-00000A-02-0051
   Rebuttal Testimony on behalf of Constellation NewEnergy, Inc. and Strategic Energy L.L.C. August 29, 2003.

9. Arizona Corporation Commission No. E-01345A-03-0437
   Direct Testimony on behalf of Constellation NewEnergy and Strategic Energy, Inc. February 3, 2004

10. CPUC Rulemaking 03-10-003
    Direct Testimony of Mark E. Fulmer on Behalf of The City and County of San Francisco on Community Choice Aggregation Transaction Costs. April 15, 2004
11. CPUC Rulemaking 03-10-003
    Reply Testimony of Mark E. Fulmer on Behalf of The City and County of San

Francisco on Cost Responsibility Surcharge for Community Choice Aggregation. May 7, 2004

12. CPUC Rulemaking 03-10-003
Rebuttal Testimony of Mark E. Fulmer on Behalf of The City and County of San Francisco on Cost Responsibility Surcharge for Community Choice Aggregation. May 20, 2004

13. CPUC Rulemaking 04-04-003
Testimony of Mark Fulmer on Behalf of Strategic Energy LLC and Constellation NewEnergy concerning the Long Term Procurement Plans of PG&E, SCE and SDG&E. August 6, 2004

14. CPUC Rulemaking 04-04-003
Rebuttal Testimony of Mark Fulmer on Behalf of Strategic Energy LLC and Constellation NewEnergy concerning the Long Term Procurement Plans of PG&E, SCE and SDG&E. August 20, 2004

15. CPUC Rulemaking 03-10-003
Opening Testimony of Mark E. Fulmer on Behalf of the City and County Of San Francisco on Allocation of Costs for Community Choice Aggregation Phase 2. April 28, 2005

16. CPUC Rulemaking 03-10-003
Opening Testimony of Mark E. Fulmer on Behalf of the City and County of San Francisco on Allocation of Costs for Community Choice Aggregation Phase 2 (April 28, 2005)

17. CPUC Rulemaking 04-12-014
Testimony of Mark E. Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning Southern California Edison's Test Year 2006 General Rate Case Application (May 6, 2005)

18. CPUC Rulemaking 03-10-003
Rebuttal Testimony of Mark E. Fulmer on Behalf of the City and County Of San Francisco on Allocation of Costs for Community Choice Aggregation Phase 2. (May 16, 2005)

19. CPUC Rulemaking 04-12-014
Testimony of Mark E. Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning Southern California Edison's Test Year 2006 General Rate Case Application (May 25, 2005)

20. CPUC Application 06-03-005
    Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition Concerning Phase 2 of the Pacific Gas and Electric Co.2007 General Rate Case Marginal Cost, Revenue Allocation and Rate Design (October 27, 2006)

21. CPUC Application 07-01-045
    Testimony of Mark E. Fulmer on Behalf of The Alliance for Retail Energy Markets and The California Manufacturers and Technology Association Concerning Southern California Edison's Application to Update is Direct Access and Other Service Fees (June 22, 2007)

22. CPUC Rulemaking 08-03-002
    Testimony of Mark Fulmer Behalf of Debenham Energy, LLC. Concerning Tariffs Supportive of Green Distributed Generation (October 31, 2008)

23. CPUC Application 09-02-022
    Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition Concerning Pacific Gas & Electric's 2009 Rate Design Window Application (July 31, 2009)

24. CPUC Application 09-02-019
    Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition Concerning the Cost Recovery Proposed By PG&E in its Application to Implement A Photovoltaic Program (August 14, 2009)

25. CPUC Application 09-12-020
    Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition Concerning Phase 1 Of Pacific Gas & Electric Company's Test Year 2011 General Rate Case (May 19, 2010)

26. CPUC Application 10-03-014
    Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition Concerning Phase I1 Of Pacific Gas & Electric Company's Test Year 2011 General Rate Case (October 6, 2010)

Exhibit D

Margaret A. Meal, CFA

Professional Experience

Manager of Regulatory and Legislative Affairs, San Francisco Public Utilities Commission, Power Enterprise (February 2010 to present):

Expertise, analysis and advocacy regarding regulatory issues that affect the SFPUC's electricity operations and its clean power initiatives. Policy development and analysis, economic analysis and business planning, and analysis and assessment of power markets and commercial opportunities. In-depth understanding of current and proposed state and federal energy policies and regulations, rate making, rate design and cost structures for electric utilities, and risk assessment of power supply alternatives.

Independent Consultant (1997-2010):

Consulting services including financial advisory services, business planning and regulatory advocacy, including complex analysis of business and regulatory constraints and opportunities in the power sector.
- Investment screening, selection, structuring, due diligence, documentation and closing
- Economic and financial analysis, including financial structuring, risk assessment, analysis and negotiation of power purchase and other commercial agreements, due diligence, asset and corporate valuations
- Develop business plans, market and technology assessments, debt and equity offerings
- Analysis of electric utility regulation, ratemaking and procurement plans
- Oral and written testimony before Public Utilities Commissions in California, Colorado, Michigan, Minnesota and Oregon, and before the California State Senate Energy, Utilities and Communications Committee

Representative clients include trade associations, municipal utilities, independent power companies and a consumer group.

Senior Project Manager and Principal, MRW & Associates, Inc. (1991-1997):
- Structured and negotiated debt and equity investments in renewable and conventional power facilities, focusing on investments and acquisitions in emerging technologies and emerging power market structures.
- Provided strategic advice to new and established market players regarding financial structuring, market potential, regulatory constraints and uncertainties, and competitive threats and opportunities.
- Prepared bids for corporate and asset acquisitions and detailed financial models supporting those bids.
- Led project teams, managed project budgets and supervised and trained junior staff.

Assistant Vice President, Trust Company of the West (1989-1991):

Structured, negotiated and managed debt and equity investments in renewable, waste fuel and cogeneration facilities for a $200 million pension fund portfolio, focusing on creating new financial structures (mezzanine debt and preferred equity positions) to fill existing capital market gaps. Detailed project and investment analysis including contract review, asset valuation, projections of financial performance and estimates of expected returns and variability of returns under varying market conditions.

Education

BS, Stanford University, Civil Engineering, with distinction; Tau Beta Pi
MS, University of California at Berkeley, Energy and Resources
Chartered Financial Analyst (CFA), CFA Institute and Member, CFA Society of San Francisco

WRITTEN AND ORAL TESTIMONY

Before the California Public Utilities Commission in A.10-03-014, on behalf of the City and County of San Francisco, in Pacific Gas and Electric Company's 2011 General Rate Case Phase 2, regarding PG&E's proposals to introduce a Conservation Incentive Adjustment and otherwise modify its residential rate design (rebuttal testimony October 2010, revised November 2010).

Before the Michigan Public Service Commission, on behalf of the Michigan Wholesale Power Association, in Consumers Energy's and Detroit Edison's Renewable Energy Plan proceedings, regarding financing constraints and debt equivalence costs and penalties for bidders offering long term power purchase agreements in the utilities' proposed design of their requests for proposals and bid evaluation for procurement of renewable resources (Consumers Energy testimony March 2009, Detroit Edison testimony April 2009).

Before the Public Utilities Commission of Colorado, on behalf of the Colorado Independent Energy Association, in Public Service Company of Colorado's 2007 Integrated Resource Plan proceeding, regarding the impact of power purchase agreements on the credit profile of Public Service Company of Colorado and the use of proposed adders in bid evaluation (answer testimony April 2008; cross-answer testimony June 2008).

Before the California Public Utilities Commission in R.06-02-013, on behalf of Hercules Municipal Utility, regarding proposals for non-bypassable charges to be imposed on departing customers (April 2007).

Before the California Public Utilities Commission in R.06-02-013, on behalf of the Independent Energy Producers Association, regarding the impact of power purchase agreements on the credit profiles of the California investor-owned utilities (March 2007).

Before the Minnesota Public Utilities Commission, on behalf of Excelsior Energy, Inc., regarding the impact of a proposed power purchase agreement on the credit profile of Northern States Power Company (Minnesota) (October 2006).

Before the Public Utilities Commission of Colorado, on behalf of the Colorado Independent Energy Association, regarding the impact of power purchase agreements on the credit profile of Public Service Company of Colorado (August 2006).

Before the City and County of San Francisco Assessment Appeals Board, on behalf of the City and County of San Francisco, regarding the fair market value of the Potrero Power Plant (November 2005).

Before the California State Senate Energy, Utilities and Communications Committee, on behalf of The Utility Reform Network, to describe and quantify the impacts of various plans of reorganization on both PG&E's ratepayers and PG&E's shareholders (September 2003).

Before the California Public Utilities Commission in OII 02-04-026 (Ratemaking Implications of the PG&E Bankruptcy), on behalf of The Utility Reform Network, quantifying the cost of PG&E's proposed settlement agreement for ratepayers, and demonstrating that the excess cost generates windfall profits for PG&E's shareholders as compared to traditional cost-of-service ratemaking (August 2003).

Before the California Public Utilities Commission in OII 02-04-026 (Ratemaking Implications of the PG&E Bankruptcy), on behalf of The Utility Reform Network, regarding the savings potential of using a bond issuance supported by a dedicated rate component as part of a plan for Pacific Gas and Electric Company's emergence from bankruptcy (January 2003).

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Electric Industry Restructuring Implications for Project Financing. 13th Annual Meeting of the Independent Energy Producers Association. Fallen Leaf Lake, CA. November 1, 1994.

CERTIFICATE OF SERVICE

I, KIANA V. DAVIS, declare that:

I am employed in the City and County of San Francisco, State of California. I am over the age of eighteen years and not a party to the within action. My business address is City Attorney's Office, City Hall, Room 234, 1 Dr. Carlton B. Goodlett Place, San Francisco, CA 94102; telephone (415) 554-4698.

On January 31, 2011, I served:

TESTIMONY OF
JOHN P. DALESSI
MARK E. FULMER
MARGARET A. MEAL
ON BEHALF OF
THE JOINT PARTIES
ON
A FAIR AND REASONABLE METHODOLOGY TO DETERMINE THE POWER CHARGE INDIFFERENCE ADJUSTMENT (PCIA) AND THE COMPETITION TRANSITION CHARGE (CTC)Y

by electronic mail on all parties in CPUC Proceeding No. R.07-05-025

The following addresses without an email address were served:

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

CLINT SANDIDGE
MANAGER, POLICY & REGULATION
RRI ENERGY, INC.
1000 MAIN STREET
HOUSTON, TX 77002

MALCOLM REINHARDT
ACCENT ENERGY
1299 FOURTH STREET, SUITE 302
SAN RAFAEL, CA 94901

LES GULIASI
DIRECTOR, REGULATORY AFFAIRS
RRI ENERGY, INC
720 WILDCAT CANYON ROAD
BERKELEY, CA 94708

I declare under penalty of perjury that the foregoing is true and correct and that this declaration was executed on January 31, 2011, at San Francisco, California.

/S/

KIANA V. DAVIS