BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

WORKSHOP REPORT OF THE JOINT PARTIES

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AND ON BEHALF OF THE JOINT PARTIES

January 14, 2011

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WORKSHOP REPORT OF THE JOINT PARTIES

I. INTRODUCTION AND SUMMARY

As directed in the *Assigned Commissioner's Ruling Adopting Amended Scoping Memo and Schedule* ("Scoping Memo"), issued on November 22, 2010, as amended by the e-mail rulings issued on November 24, 2010 and January 7, 2011, this workshop report is filed by the Marin Energy Authority, the Direct Access Customer Coalition, the Alliance for Retail Energy Markets, the City and County of San Francisco, the California State University, the California Municipal Utilities Association, Commercial Energy, Pilot Power Group, Inc., Energy Users Forum, BlueStar Energy, San Joaquin Valley Power Authority, the School Project for Utility Rate Reduction and the Retail Energy Supply Association ("RESA")[1] (collectively, the "Joint Parties"). While the workshops have led to productive exchanges on a number of issues, the parties have not reached full resolution of the issues. As noted at the conclusion of this workshop report, the Joint Parties are willing to engage in continued discussion with all parties in this proceeding to attempt to achieve resolution of the issues outlined below, provided that continued discussions do not cause the schedule set forth in the Scoping Memo for testimony and a final decision to be delayed.

[1] RESA's members include: Champion Energy Services, LLC; ConEdison *Solutions*; Constellation NewEnergy, Inc.; Direct Energy Services, LLC; Energy Plus Holdings, LLC; Exelon Energy Company; GDF SUEZ Energy Resources NA, Inc.; Green Mountain Energy Company; Hess Corporation; Integrys Energy Services, Inc.; Just Energy; Liberty Power; MXenergy; Gexa Energy; Noble Americas Energy Solutions LLC; PPL EnergyPlus; Reliant Energy Northeast LLC. The comments expressed in this filing represent the position of RESA as an organization but may not represent the views of any particular member of RESA.

II. <u>OVERVIEW OF THE WORKSHOPS</u>

There have been four workshop meetings, on December 7, 2010, December 14, 2010, December 15, 2010, and January 4, 2011, each directed by Energy Division staff. Over the course of the workshops, there were eight separate presentations, as follows:

1. *Addressing RPS Compliance Costs in the PCIA/Indifference Calculation* presented by Mark Fulmer on behalf of the Joint Parties on December 7, 2010 ("Presentation #1).
2. *Concerns With The Current Indifference Methodology* presented by Meg Meal on behalf of City and County of San Francisco and the Joint Parties on December 7, 2010 ("Presentation #2").
3. *Market Price Benchmark Refinements: CAISO Services* presented by John Dalessi on behalf of the Joint Parties on December 7, 2010 ("Presentation #3").
4. *Indifference Calculation Modification* presented by Pacific Gas & Electric ("PG&E") on December 7, 2010 ("Presentation #4").
5. *Cost Responsibility Surcharge Development of Indifference Amount* presented by Southern California Edison ("SCE") on December 7, 2010 ("Presentation #5").
6. *Joint SCE/PG&E Proposed Modification of Indifference Amount Calculation* presented by SCE on December 14, 2010 ("Presentation #6")
7. *Switching Rules for CCA Programs* presented by Marin Energy Authority on December 15, 2010 ("Presentation #7").
8. *Joint Parties Counterproposal on PCIA Reform* presented by Mark Fulmer on behalf of the Joint Parties on January 4, 2011 ("Presentation #8").

Presentations 1-3 and 5-8 are attached to this report. In addition, the investor owned utilities ("IOUs") provided specific data in response to an e-mail request sent to the working group participants by Energy Division staff on December 14, 2010. Each utility's data response is also attached to this report. The Joint Parties are appreciative of the opportunity that the workshops provided for exchanging and discussing proposals to modify the Power Charge Indifference Amount ("PCIA"). Reforms to the PCIA calculations, especially the Market Price Benchmark ("MPB"), are urgently needed in light of very significant increases that have already been put into effect for PG&E's PCIA for 2011, and that are expected to go into effect for SCE and San Diego Gas & Electric ("SDG&E"). In the next section of this report, the Joint Parties set forth their views on the status of each of the topics raised in the workshops.

While this report attempts to summarize issue by issue the tenor of the discussions at the workshops, the proposals put forward by the Joint Parties on the one hand and by the IOUs on the other were presented as packages. Thus, tentative agreement on individual issues is conditioned on achieving agreement on related issues. The Joint Parties presented a comprehensive proposal responsive to the proposal of the IOUs addressing all issues related to the PCIA. The IOUs represented that their proposal is conditioned on resolution of all Phase 3 issues, including switching rules and financial assurance issues currently subject to further proceedings in this and in the community choice aggregation ("CCA") docket R.03-10-003.

III. STATUS OF WORKSHOP ISSUES

A. Green Benchmark Adder

There is general agreement among the parties that the PCIA calculation needs to be modified to reflect the value of the IOUs' renewable procurement commitments that are assigned to departing load. The Joint Parties and the IOUs have each made specific proposals to address this issue, but have not reached consensus, as reflected in the presentations. (See presentations # 6 and #8.)

B. Capacity Adder

The Joint Parties did not initially propose a change to the Capacity Adder in the MPB. The IOUs in turn proposed to value the capacity embedded in their portfolios based on the payment made by the California Independent System Operator ("CAISO") when it purchases capacity under it Interim Capacity Procurement Mechanism ("ICPM"), as that payment is reflected in the CAISO tariff, and as it may be modified over time. (See presentation #6.) The Joint Parties have expressed that the proposal put forth by the IOUs may be acceptable, conditioned on further review and explanation of the information provided by the IOUs in order to verify that the ICPM is applied to the Net Qualifying Capacity ("NQC") of all of the resources included in the PCIA calculation (by vintage) for each IOU. In addition, in the future such information should be made publicly available and independently verified by the Energy Division and an independent third party.

C. CAISO Costs

In the first workshop, the Joint Parties proposed including tariffed CAISO costs in the Market Price Benchmark. (See presentation #3.) The IOUs proposed that load-related CAISO costs should be eliminated from the Total Portfolio Costs of each vintage year. (See presentation #6.) Joint Parties have tentatively agreed that eliminating appropriate CAISO costs from the Total Portfolio Costs can adequately address this issue, subject to verification by the Energy Division and an independent third party that all appropriate CAISO costs have in fact been removed from the Total Portfolio Costs.

D. LAP-HUB adder

While the Joint Parties have tentatively agreed that eliminating the appropriate CAISO costs from the Total Portfolio Costs would be an acceptable modification to the PCIA, an issue remains of whether or not there should be an adjustment to the MPB to reflect the fact that there is a differential between prices at the CAISO defined hubs and the load aggregation points ("LAP") that are the ultimate points of delivery for the IOUs. PG&E stated that all congestion costs, including costs for congestion between the hub and the LAP, are included in its forecast of CAISO costs and that removal of CAISO costs as discussed in C above would address the Joint Parties concerns. SCE stated that it does not include a forecast of congestion costs between the hub and the LAP in its rates, which raises the question of how these congestion costs incurred by SCE are ultimately recovered in SCE's rates and the potential for systematic under-collections. Unless all congestion costs are included in the IOU forecast of CAISO costs and these CAISO costs are removed from the Total Portfolio Cost, the Joint Parties believe that an adder should be included in the MPB to reflect the cost of congestion between the hub and LAP prices.

E. Short Term Purchases

In the course of the workshops, PG&E noted that short term purchases (net of short term sales) that it makes are not included in the Total Portfolio Costs for any vintage year. SCE reported that it does include those costs in the total portfolio, but that it would prefer to adopt PG&E's practice. The Joint Parties have asked for aggregated information from each of the IOUs on the quantity and costs of short term purchases so that they can assess the impact of these purchases on the PCIA. Upon receipt of this information, the Joint Parties will be better able to formulate a position on this issue.

F. Shaping Portfolio Power

In the first workshop, the Joint Parties noted that the MPB does not include the value of resources needed to serve the shaped load of customers even though costs associated with these resources are included in the Total Portfolio Costs. (See presentation #3.) The Joint Parties proposed that the forwards-based portion of the MPB be load-weighted based on the bundled customer load profile. (See presentations #3 and #8.) The IOUs responded that the weighting be based upon its "generator profile," which includes only the production profile of the long-term resources (i.e., it does not include the contribution of any spot- or short-term purchases.) (See presentation #6). The Joint Parties tentatively do not oppose the IOU's approach, subject to further review and analysis.

G. Application of changes to the MPB to the calculation of the CTC

The Joint Parties have expressed the view that the modifications adopted for the MPB calculation should be made applicable to the calculation of the Competitive Transition Charge ("CTC"). The IOUs have not agreed to that position.

H. PCIA-URG and PCIA-DWR issues

SCE has asked that its DA-CRS tariff be simplified so as not to explicitly show "PCIA-URG" and "PCIA-DWR" designations for each departing load type and vintage but a single PCIA for each departing load type and vintage. The Joint Parties do not object to those modifications.

I. Continuous DA customers

SCE noted that customers who are Continuous DA do not lose their "continuous DA status" when they return to bundled service and then subsequently re-return to direct access service. SCE notes that this retention results in non-optimal CRS outcomes. The Joint Parties do not have a position on this issue.

J. Transition Bundled Service Rate

The Joint Parties have generally agreed with the IOUs that the TBS rate should be calculated in a manner consistent with the calculation of the MPB. The Joint Parties emphasize, however, that the TBS rate must include all costs relevant to procuring energy and serving load, including all relevant CAISO charges. The Joint Parties have requested from each IOU, but not yet received, a listing of the specific CAISO charge codes currently included in the TBS to determine whether additional charge codes should be added. (See Section L below for additional issues associated with the TBS rate.)

K. PCIA/CTC Issues

As established in D.06-07-030, the PCIA is calculated residually: the PCIA equals the Indifference Rate minus the CTC. Thus, the PCIA is the rate tool by which bundled customer indifference criterion is maintained. This calculation can reasonably result in a negative PCIA, so long as the underlying Indifference Rate is no less than zero.[2] The IOUs have proposed that the PCIA should not be allowed to go negative (See presentation #6). The Joint Parties oppose this proposal.

L. Other Phase III Issues

At the time the Assigned Commissioner agreed to expand this proceeding to include review of the PCIA as requested in the Joint Parties Motion of September 23, 2010, there had been substantive discussions on all other Phase III issues. On November 15, 2010, as directed by the June 15, 2010 *Assigned Commissioner and the Administrative Law Judge Ruling Clarifying Scope and Scheduling Further Proceedings*, parties submitted reports to the Commission. In those reports, several Phase III issues were resolved or deferred to other proceedings. However, the parties had been unable to reach agreement on the issues under consideration by "Working Group 1" which included issues associated with Transition Bundled Rate, switching rules and ESP financial security requirements, even though the Direct Access Parties[3] submitted a comprehensive proposal for addressing these issues.[4] The inability to resolve these issues has

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[2] In practice, a floor of zero is set for the Indifference Rate. In years when the Indifference Rate calculation is negative, the negative amount is "banked" and credited against future positive Indifference Rates.

[3] The Direct Access Parties are Alliance for Retail Energy Markets (AReM), BlueStar Energy, California Alliance for Choice in Energy Solutions (CACES), California Large Energy Consumers Association (CLECA), California Manufacturers and Technology Association (CMTA), California State University (CSU), Direct Access Customer Coalition (DACC), Energy Users Forum (EUF), School Project for Utility Rate Reduction (SPURR), and Walmart.

[4] A copy of that report is appended to this report.

been due, at least in part, to the fact that the parties disagree on the statutory requirements associated with the ESP financial security requirements, and the ALJ had required the parties to submit legal briefs on this issue on April 15, 2010. The e-mail ruling issued by ALJ Pulsifer on January 7, 2011 approved the request made by parties at the January 4 workshop to expedite resolution of this threshold statutory interpretation disagreement by moving up the date of the required legal briefs to January 24, 2011.

In the meantime, Joint Parties remain concerned about comments made by the IOUs at each of the four workshops described herein (presentation #6, page 2) that they are unprepared to reach consensus on any of the issues associated with modifications to the PCIA unless and until consensus is reach on ALL of remaining Phase III issues, specifically including the financial security requirements, as the IOUs apparently believe a partial settlement will reduce their negotiating flexibility. Joint Parties urge the Commission to assist in ending the current stalemate by demonstrating an intention to quickly resolve all of these issues. Specifically, in requesting that the ALJ accelerate the date for filing legal briefs on the statutory interpretation issue which is the key to the financial security requirement, the moving parties asked that the Commission issue an expedited interim decision on that single issue at the earliest opportunity. Whether such an interim decision is issued prior to or after hearings are held on the material factual issues in the case, it will certainly resolve a major obstacle to meaningful settlement discussions, and it could greatly facilitate a resolution on the other issues in this Phase of the proceeding.

At the same time, the Commission should recognize and acknowledge that there is little, if any, nexus between the issues involved in updating and improving the PCIA calculation and the remaining Phase III issues—the TBS rate, switching rules, and financial security requirements--which most parties agree are interconnected. Accordingly, the Commission should move quickly to resolve each set of issues as quickly as possible, even if that means issuing interim decisions on specific issues rather than waiting to issue a single comprehensive decision on all the issues in this Phase of the proceeding..

IV. CONCLUSION

The Joint Parties are grateful for the Energy Division Staff's leadership in the workshops that have taken place. Significant progress has been made, although no comprehensive agreement was reached. While Joint Parties believe that additional discussion may be fruitful, Joint Parties would not support, at this time, any delay in the procedural schedule established in the Scoping Memo.

Respectfully submitted,

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January 14, 2011

Presentation 1

Addressing RPS Compliance Costs in the PCIA/Indifference Calculation

Workshop # 1 on Departing Load PCIA Methodologies

Presented by Mark Fulmer, MRW & Associates LLC
On behalf of the Joint Parties

December 7, 2010

Problem:

- The current Market Price Benchmark does not reflect the value of renewable resources even though the cost of these resources is included in the Indifference Rate calculation underlying the PCIA.
- As a result, above market costs are inappropriately shifted to departing load customers.

Potential Options

1. Remove all RPS renewables (costs and MWhs) from the indifference calculation
2. Adjust the Market Price Benchmark to reflect RPS values
3. Segregate RPS resources from conventional and create a separate benchmark/indifference calculations for each
4. Allocate a share of the renewable attributes to CCAs/ESPs.
5. *Other ideas?*

1. Remove RPS from the Indifference Calculation

Rationale:

- Consistent with flexible RPS compliance
- RPS assets are never “stranded” as long as the departed load doesn’t cause the IOU to be excessively long on RPS power
- Departing loads are responsible for costs of their own RPS compliance
- Simplicity: don’t have to construct a price proxy for renewable power

2: Adjust the Market Price Benchmark

- Have the market price benchmark equal a weighted average of the brown market power forwards and a green price benchmark
- Weight the two factors based on that year's RPS requirement
- E.g., assuming a 20% RPS requirement, the Market Price Benchmark would equal:

(Forward Price x 80% + Green Benchmark x 20% + other adders) x (1+ line losses)

2: Adjust the Market Price Benchmark

Example: Based on SCE November ERRA:

- Average 2011 Forwards: $35.27/MWh
- RA Adder: $7/MWh
- Line Losses: 5.3%
- Current Benchmark: ($35.27 + $7) x 1.053 = $44.51

- Green Benchmark: $120/MWh*, 20% RPS requirement
- New Benchmark:

[(0.8 x $35.37) + (0.2 x $120) + $7] x 1.053 = $62.35/MWh

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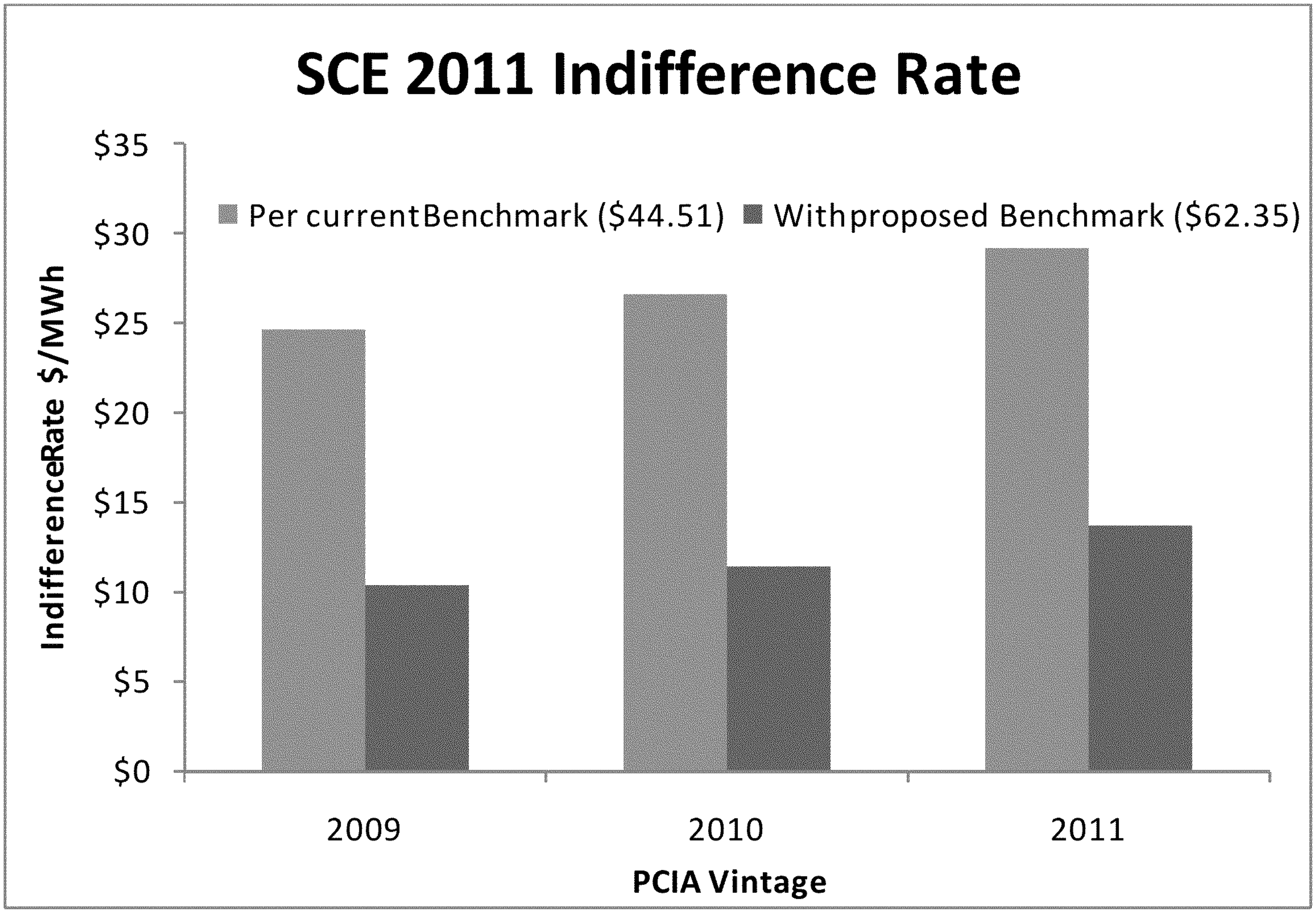
* $120/MWh is for illustration purposes only

Impact of Weighted Average Benchmark on Indifference Rate



How Should a Green Benchmark Be Set?

- RPS Market Price Referent (MPR)
  - But the MPR is long-term index
- REC values
  - REC market does not yet exist, so does not address immediate need for relief
- Some other "Green" Market Price
  - No published indices
- A Proposal: Infer market price from current year's IOU RPS-compliant purchases

Green Benchmark Proposal

The benchmark in year *n* would be the weighted average cost of all new renewable PPAs and utility-owned RPS compliant resources entering the revenue requirement in year *n*.

Green Benchmark Proposal

Rationale:

- We need a current price for the full spectrum of renewables
- The California IOUs are the primary buyers of renewables in the state (and likely the WECC)
- What the major buyers are paying for renewables is *de facto* what the market price is, as they are conducting most of the transactions

Green Benchmark Proposal

- Issues:
  - There would be some volatility, as the mix of new resources would change from year to year. How much? How big a problem would it be?
  - Would the Green Benchmark be IOU specific or a weighted average of all three?
  - How would it be reported, so as to protect IOU confidentiality AND provide for independent verification?

3. Separate RPS and conventional indifference calculations

- Create two parallel calculations based on two sets of resources and costs: those used for RPS compliance and those not.
- Use the Green Benchmark to calculate the indifference rate associated with RPS-compliant resources
- Use a brown/market benchmark to calculate the indifference rate associated with non-RPS resources

3. Separate RPS and conventional <u>indifference calculations</u>

- Each calculation would be based on the actual volumes in the RPS and non-RPS bucket
- Would allow more transparency in the Indifference rates
- Would add a level of complexity –two indifference calculations rather than one.

4. Allocate renewable attributes to CCAs/ESPs

- If no green benchmark is added, transfer some RPS attributes (RECs and/or any RPS compliance elements) to the providers of the departed load (CCAs and ESPs)
- How?

Recap

- Remove RPS renewables from the calculation
  - Avoids all need to set a benchmark for renewables
- Adjust the Market Price Benchmark for RPS
  - A challenge to come up with a Green Benchmark
- Separate Indifference calculations for brown and green power
  - Adds transparency but also complexity
- Allocate some portion of the renewable attributes to CCAs/ESPs
  - How?

Presentation 2

Concerns With The Current Indifference Methodology

CleanPowerSF
San Francisco Public Utilities Commission
And on behalf of the Joint Parties

December 7, 2010
CPUC Workshop Regarding Revisions to the PCIA Methodology
R 07-05-025

What we learned from PG&E's 2011 ERRA Forecast Proceeding

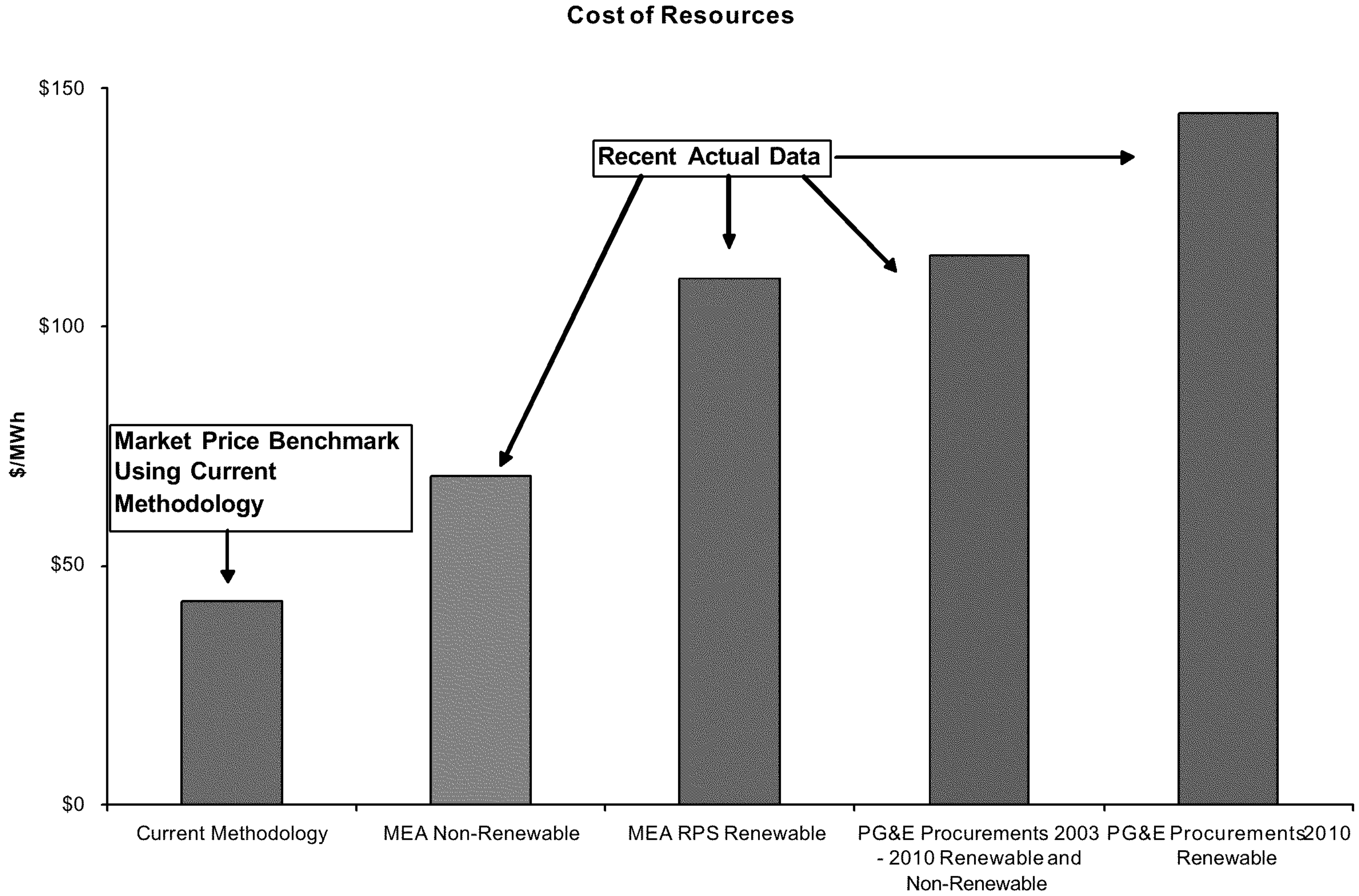
- Market prices based on recent transactions are significantly higher than market prices that fall out of the current Market Price Benchmark (MPB) formula

- Several attributes (and IOU costs) are included in the IOU resource portfolios assigned to departing load, but neither the value of these attributes nor the IOU costs are reflected in the Market Price Benchmark

- Result: Market value is understated
  Above market costs are overstated
  Bundled customer indifference is not achieved

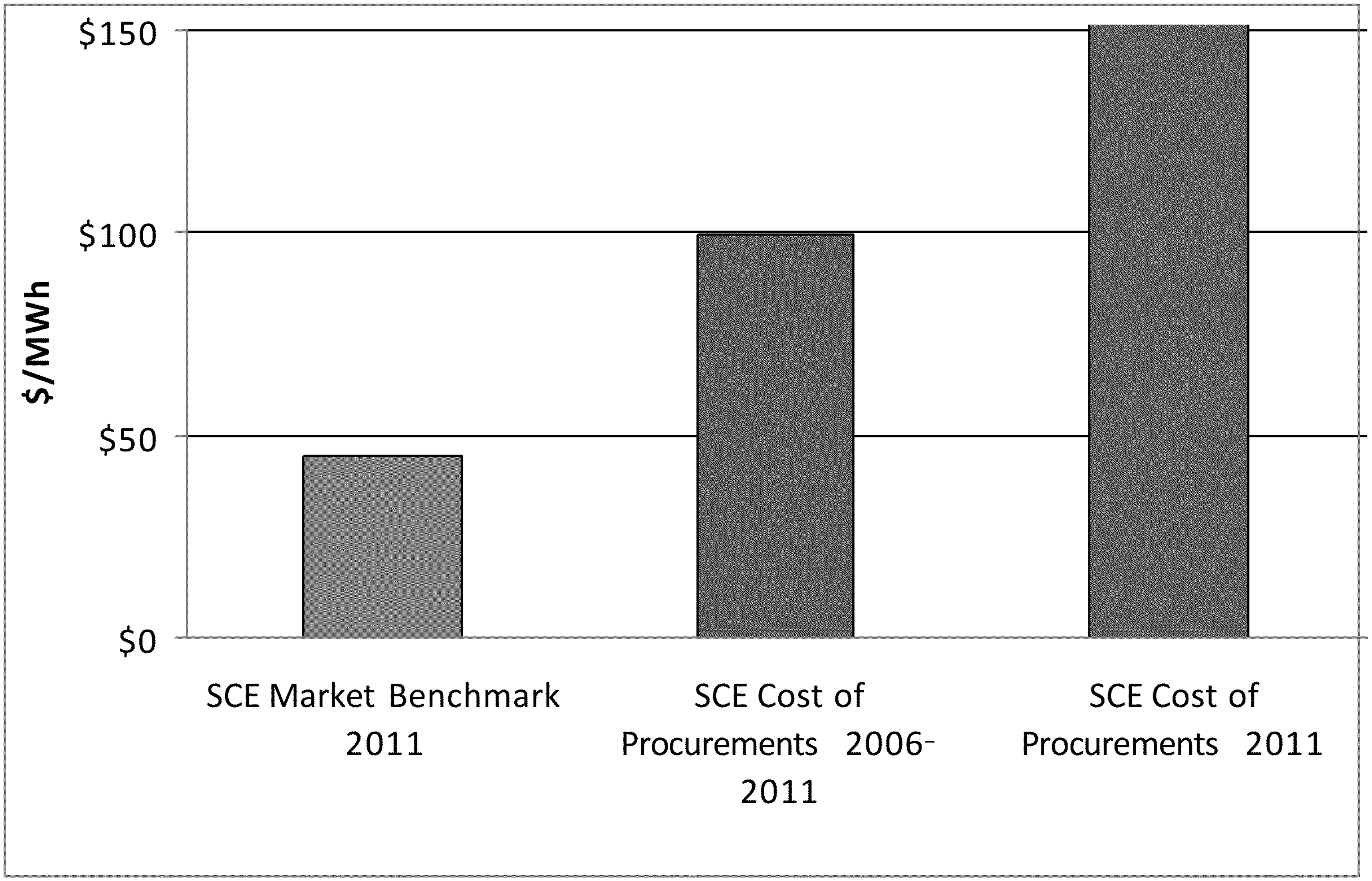
Current Market Price Benchmark compared to recent market data

(PG&E ERRA 2011, based on November 5, 2010 update)



SCE ERRA 2011 Results are Similar

(SCE ERRA 2011, based on SCE's November 10, 2010 update)



Current Indifference Methodology

Compare:	IOU cost of procurement commitments made on behalf of bundled and departing load: **Total Portfolio Cost**
To:	Market cost of those commitments based on a **Market Price Benchmark**
Where:	Current Market Price Benchmark (PG&E) = NP15 (24x7) + Capacity Adder ($4/MWh) x 1.06 for distribution losses

Current MPB excludes key attributes included in Total Portfolio

<u>Total Portfolio:</u>

- Includes non-RPS and RPS resources
- Is shaped to system load profile
- Includes RA/Capacity
- Is delivered to the customer meter, including
  - CAISO costs
  - Distribution losses

<u>Market Price Benchmark:</u>

- Includes non-RPS only (NP15/SP15), **<u>no RPS</u>**
- Flat load profile, **<u>not shaped</u>**
- Includes RA adder
- Includes losses from delivery point to meter
- **<u>Excludes all other delivery costs, e.g., CAISO costs</u>**

Bundled Customers Retain All RPS Attributes and Compliance Benefits

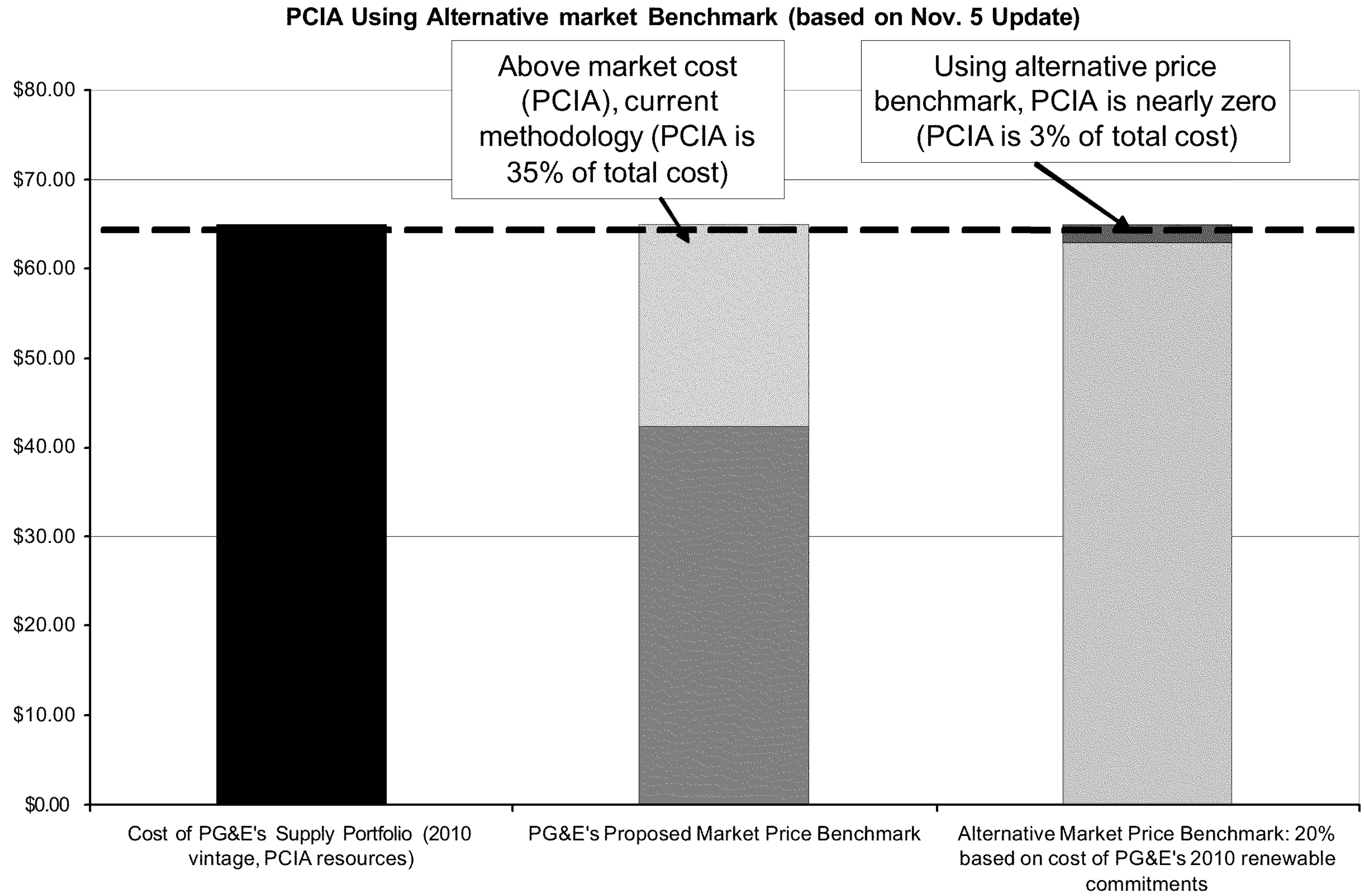
<u>Example: 100 MWh/yr bundled load</u>

- 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%
  - RPS increment can be banked or used currently by remaining bundled load

<u>Under current Indifference Methodology:</u>

- RPS attributes remain with and benefit remaining bundled customers
- Departing load pays twice: once to IOU, once to meet its own RPS requirement

Current Methodology Does Not Result in Bundled Customer Indifference



Presentation 3

Market Price Benchmark Refinements:
CAISO Services

PCIA Workshop #1

December 7th, 2010

Presented By John Dalessi,

Dalessi Management Consulting

Problem

- The market price benchmark methodology does not include the value of CAISO services even though the costs associated with CAISO services are included in the total portfolio cost.

Avoidable CAISO Charges

- As load migrates to non-bundled service, certain charges paid by the utilities to the CAISO for services will be avoided.
- These include a variety of charge types for grid management services, ancillary services and other uplift charges.
- CCAs and ESPs pay for these services directly to the CAISO and should not also pay for utilities' costs.
- Market price benchmark should also be adjusted for basis differential: i.e., the difference between the Trading Hub price (NP15 or SP15) and the Load Aggregation Point (DLAP_PG&E, DLAP_SCE, DLAP_SDG&E) price to reflect portfolio value at the appropriate delivery point.

Load Based CAISO Charges

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

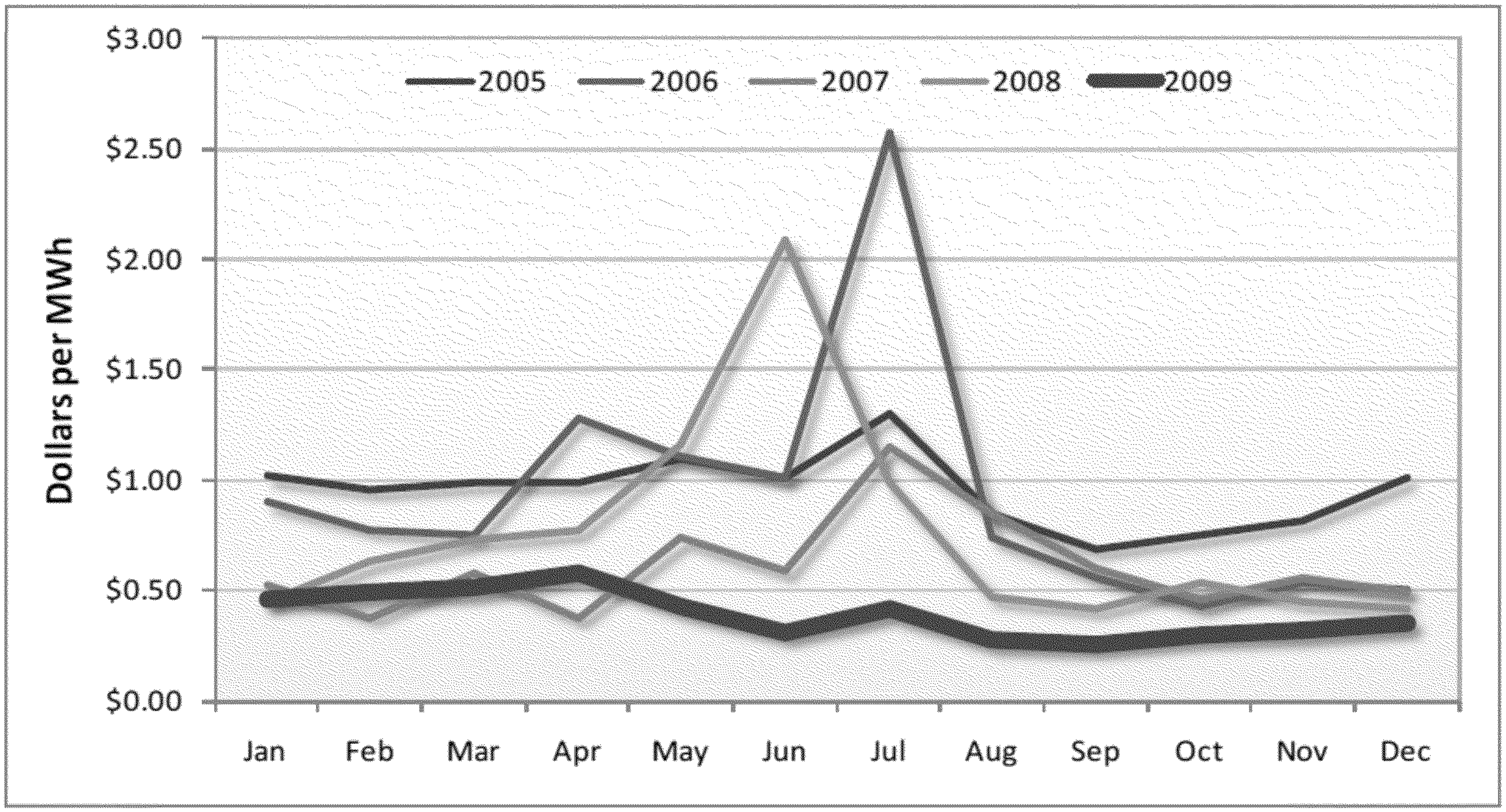
Proposed Benchmark Adjustment for CAISO Services

- Use historical data to derive average basis between Trading Hub and LAP day-ahead prices.
- Use ERRA forecast of CAISO costs for the relevant charge codes as an adder to the benchmark:

  CAISO Services Adder ($/MWh) = CAISO Cost Forecast ($)
  /Bundled Sales Forecast (MWh)
- Adjust for value of self-provided ancillary services – m a yneed to use a reasonable proxy value for ancillary services based on published CAISO data; e.g., prior year's average AS costs per MWh of load.

Ancillary Services Costs

Figure 6.3 Ancillary service cost per MWh of load (2005 – 2009)



CAISO Cost Example

- As an example of the magnitude of CAISO costs that should be included in the benchmark, MEA's load-based CAISO charges have been averaging approximately $3.25 per MWh since MEA's inception:

GMC:	$1.15
Ancillary Services:	$0.45
Other Allocated Charges:	$0.75
PG&E LAP – N P 1 5 Hub:	$1.00
Total CAISO Services	$3.25

- CAISO costs in utility portfolio should be similar, but will need data to confirm.
- Incorporating CAISO costs in benchmark using the above estimates would reduce the "indifference fee" by approximately $2.85 for PG&E and $2.75 for SCE.

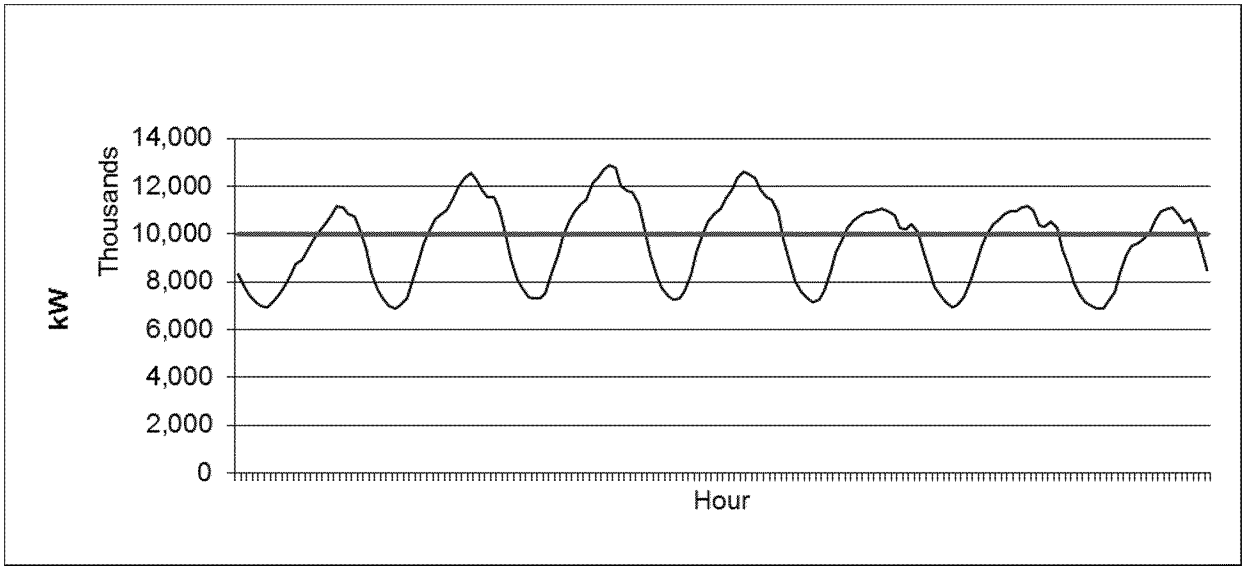
Market Price Benchmark Refinements: Shaped Delivery Profile

PCIA Workshop #1
December 7th, 2010

Presented By John Dalessi
Dalessi Management Consulting

Problem

- The market price benchmark methodology does not include the value of resources needed to serve the shaped load of customers even though costs associated with these resources are included in the total portfolio costs.



Proposed Solution

- Replace the <u>baseload</u> price used in the benchmark with a load-weighted (shaped) energy price (Load Shape Adjustment).
- For administrative simplicity, use the utility system load profile to derive the load shape adjustment.

Current Method

- Current benchmark methodology derives a baseload forward price by weighting calendar year average on-peak and off-peak forward prices by the respective on-peak and off-peak hours in the year.
- Example of current calculation:

CY2011 On-peak price ($/MWh)	40
CY2011 Of-peak price ($/MWh)	28
CY2011 On-peak hours	5,008
CY2011 Off-peak hours	3,752
Weightedaverage (calculatedbaseload) price ($/MWh)	**35**

Adjustment for Load Shape

- Could use the utility's system load shape to determine on-peak and off-peak MWh and use these values to calculate a weighted average (shaped) price.
- Utility load shapes can be estimated from publicly available information using published statistical hourly class load profiles and forecast of sales by class (ERRA).
- Sum all hourly MWh during on-peak hours (6 am to 10 pm M-Sa) in each month and sum all hourly MWh during off-peak hours in each month.
- Use these as the weighting factors in the calculation of shaped energy price.

Option 1 – Load Weighted Average, Annual

- Use on-peak and off-peak annual strips and weight by on-peak and off-peak usage.
- Captures intra-month peak and off-peak profile.

CY2011 On-peak price ($/MWh)	40
CY2011 Of-peak price ($/MWh)	28
CY2011 On-peak load (MWh)	50,000,000
CY2011 Off-peak load (MWh)	25,000,000
Weightedaverage (shaped) price ($/MWh)	**36**

Option 2 – Load Weighted Average, Monthly

- Use monthly on-peak and off-peak forward prices and weight by monthly on-peak and off-peak usage.
- Captures seasonal price/load correlations as well as intra-month peak and off-peak profile.

Month	On-peak price ($/MWh)	On-peak MWh		Month	On-peak price ($/MWh)	On-peak MWh
January	35	4,137,250		July	50	5,205,900
February	35	3,676,290		August	50	5,026,340
March	35	3,950,320		September	50	4,598,210
April	35	3,888,680		October	35	3,990,520
May	35	4,349,640		November	35	3,804,930
June	50	4,509,100		December	35	4,174,100
Weighted Average (Shaped) Price ($/MWh)				**37**		

Option 3 – Load Weighted Average, Hourly

- Neither of the previous options accounts for the positive correlation between hourly loads and prices.
- Option 3 would use a load shape adjustment to the forward baseload price. The adjustment would be derived using historical CAISO day-ahead energy prices and the utility hourly system load shape:

  Shape Factor = $\sum_{i\ 1}^{8760} P_i L_i \,/\, \sum_{i\ 1}^{8760} L_i \,/\, AvgPi$

  Where P_i equals CAISO day ahead price in hour i and L_i equals utility system load in hour i.

- Multiply calculated baseload price (per current methodology) times the Shape Factor.

Presentation 5

Cost Responsibility Surcharge Development of Indifference Amount

DA OIR Phase III Workshop
December 7, 2010

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Adopted Methodology

- Pursuant to D.06-07-030 (as modified), SCE develops an "indifference amount" annually in the ERRA forecast proceeding;
  - For each vintage year, SCE calculates the cost of the total portfolio of all generation resources signed in that year to serve bundled service customers' load.
  - The generation portfolio for each vintage year includes all resources and contracts entered into to serve bundled load for that year.
  - Energy Division produces a market price benchmark (MPB) for the forecast year, which includes:
    - Value of energy (average price for a 12-month forward strip over 31 days in October)
    - Value of RA/generation capacity (per MWh adder)
    - Line losses (per MWh adjustment)
  - Each portfolio is valued at the MPB to produce a market value for the total portfolio.
  - The market value of the portfolio is subtracted from the total portfolio cost for each year to determine any above-market costs, identified as the "indifference amount," which can be positive or negative.
  - Statutory CTC revenue is subtracted from the indifference amount to produce the Power Charge Indifference Adjustment (PCIA).
  - CTC and PCIA revenue requirements are allocated to individual rate groups using the top 100-hours method to determine rates.

Adopted Methodology – Example

Southern California Edison Company
Illustrative Vintaged Indifference Rate Calculation
2011

	VINTAGE									
	Pre 2003	2003	2004	2005	2006	2007	2008	2009	2010	2011
Supply (GWhs)	56,402	56,402	56,402	56,412	62,565	65,642	69,744	72,820	77,948	79,998
Supply At Cust Meter	53,590	53,590	53,590	53,600	59,446	62,369	66,266	69,189	74,061	76,010
Total Portfolio Cost ($000)	3,530,145	3,530,145	3,530,145	3,530,412	3,970,792	4,290,981	4,592,901	5,038,091	5,346,740	5,635,200
Market Price Benchmark ($/MWh)	44.51	44.51	44.51	44.51	44.51	44.51	44.51	44.51	44.51	44.51
Market Cost ($000)	2,385,288	2,385,288	2,385,288	2,385,721	2,645,934	2,776,041	2,949,516	3,079,623	3,296,467	3,383,205
Vintaged Above Market Cost	1,144,857	1,144,857	1,144,857	1,144,691	1,324,857	1,514,940	1,643,384	1,958,468	2,050,273	2,251,995
Total GWh Sales (All Customers)	86,710	86,710	86,710	86,710	86,710	86,710	86,710	86,710	86,710	86,710
System Avg. Indifference Rate ($/MWh)	13.20	13.20	13.20	13.20	15.28	17.47	18.95	22.59	23.65	25.97
Vintaged Above Market Cost	1,144,857	1,144,857	1,144,857	1,144,691	1,324,857	1,514,940	1,643,384	1,958,468	2,050,273	2,251,995
Less: On-Going CTC	597,638	597,638	597,638	597,638	597,638	597,638	597,638	597,638	597,638	597,638
System Level PCIA Rev Rqmt	547,219	547,219	547,219	547,053	727,219	917,302	1,045,746	1,360,830	1,452,635	1,654,357

Adopted Methodology – Historical Indifference Rates

Vintaged DA/CCA CRS

	AL 2225.-E 2008	AL 2320-E 2009	AL 2336-E 2009	AL 2346-E 2009	AL 2446-E 2010	A.10-08-001 2011
Market Price Benchmark (MPB) ($/MWh)	77.91	71.16	71.16	71.16	61.64	44.51
Indifference Charge ($/MWh)						
2001/2002	4.54	3.46	4.28	3.78	4.06	15.87
2003	4.63	3.82	4.63	4.13	4.06	15.87
2004	4.63	3.84	4.66	4.15	4.09	15.87
2005	6.26	3.85	4.67	4.16	4.09	15.87
2006	9.81	7.80	8.60	8.23	6.67	17.59
2007	11.24	10.44	11.23	10.86	9.05	20.15
2008	12.50	11.42	12.21	11.84	10.17	21.27
2009		12.38	13.17	12.79	12.51	24.69
2010					13.43	26.56
2011						29.23

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Presentation 6

Joint SCE/PG&E Proposed Modification of Indifference Amount Calculation

DA OIR Phase III Workshop
December 2010

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Adopted Indifference Calculation

- Pursuant to D.06-07-030 (as modified), the utility develops an "indifference amount" annually in the ERRA forecast proceeding:
  - For each vintage year, the utility calculates the cost of the total portfolio of all generation resources assigned to that year.
  - The generation portfolio for each vintage year includes all resources and contracts entered into to serve bundled load for that year.
  - Energy Division produces a market price benchmark (MPB) for the forecast year, which includes:
    - Value of energy (average price of a 12-month forward strip)
    - Value of RA/generation capacity (per MWh adder)
    - Line losses (per MWh adjustment)
  - Each portfolio is valued at the MPB to produce a market cost ($/MWh) for the total portfolio.
  - The market cost of the portfolio is subtracted from the total portfolio cost for each year to determine any above-market costs, identified as the "indifference amount," which can be positive or negative.
  - Statutory CTC revenue is subtracted from the indifference amount to produce the Power Charge Indifference Adjustment (PCIA) amount.
  - CTC and PCIA revenue requirements are allocated to individual rate groups using the top 100-hours method to determine rates.

Proposed Modifications to the Indifference Calculation

- Market Price Benchmark
  - Update the generation capacity adder included in the MPB
  - Adjust MPB to reflect value of renewable resources in portfolio
- Total Portfolio Cost
  - Exclude forecasted CAISO costs associated with load (variable) and the IOU's short-position at ISO on a non-vintaged basis.
  - Includes cost of contracted/owned resources.
- **SCE's/PG&E's proposed modifications to the indifference calculation are predicated on:**
  - Simple changes to existing methodology based on publicly available data.
  - Continuation of DA switching rules requiring 6 month notice to depart or return to bundled portfolio service (BPS).
  - Minimum 18-month stay on BPS.
  - ESP Security Requirements for involuntary returns calculated using the method recommended in CCA Bond/Re-Entry Fee Settlement.
  - Update of the Transitional Bundled Service (TBS) rate consistent with MPB changes for generation capacity and RPS value.

Proposed Method for Including and Updating Capacity Value in MPB

- Existing Generation Capacity Adder
  - Current value of $7/MWh for SCE ($62.5/kW-yr) and $4/MWH for PG&E adopted in D.06-07-030 (based on annualized cost of combined cycle combustion turbine) is added to MPB
- Proposed method - Include a capacity adder based on the price set in the CAISO's Interim Capacity Procurement Mechanism (ICPM) (to be superseded by Capacity Procurement Mechanism (CPM)) in effect when the annual MBP is calculated.
- ICPM (or CPM) is the CAISO's capacity backstop mechanism:
  - Public source of data on capacity value
  - Reflects actual CAISO capacity payments to generators
  - Expected to be regularly updated
  - Currently $41/kW-yr, CAISO proposed CPM of $55/kW-yr pending
- Remove the existing energy adder for capacity and adjust the market cost calculation of the total portfolio by multiplying procured, net qualifying capacity (MW), by vintage, by the CPM. NQC accounts for the intermittent characteristics of certain generation resources.

Proposed Method for Reflecting Value of Renewable Resources in MPB

- Establish a MPB adder to incorporate the value of renewable energy in the portfolio using public data
  - U.S. Dept. of Energy's survey of reported contract premiums for renewable energy in the Western U.S.
  - Replace with transparent REC market value, if/when available
- Weight MPB, before loss adjustment, based on proportion of total energy portfolio supplied by RPS eligible renewable energy
  - Exclude pre-2003 resources (legacy QF's priced at avoided cost)

Example

- 2009 vintage for 2011 PCIA
  - Assume an average price of a 12-month forward strip of $50/MWh
  - Assume current ICPM value for Capacity $41/kW-yr
  - Assume renewable premium value of $20/MWh (from DOE)
  - Assume the RPS percentage of 18% in total portfolio for 2009 vintage
  - Assume total generation portfolio 60 million MWh for 12 months
  - Assume capacity portfolio (NQC) for 12 months of 150,000 MW-months
  - Calculation of Adjusted MBP ($/MWh):

    ($50*82%)+(($50+$20)*18%)=$53.60
  - Calculation of market value of energy portfolio ($/MWh):

    $53.60*60 = $3,216 M
  - Calculation of market value of capacity portfolio:

    (($41*1000)/12)*150,000= $512.5 M
  - Adjust energy for losses consistent with existing method assume 4%
- Revised market value equals $3,216*104% + $512.5 = $3,857.14
- Current market value equals ($50*60*104%)+($7*60) = $3,540.00

Proposed Indifference Amount Calculation

- Exclude forecasted costs associated with load-related ISO charge types from non-vintaged portfolio. Need to identify charge-types to be excluded.
- Exclude forecasted costs associated energy purchases at ISO to fill anticipated short position.
- Non-vintaged costs appear proportionately in all vintaged portfolios.
- Calculate revised market value, for each vintage portfolio, by adding the revised market energy (with renewable value) to market capacity.
- Subtract revised market value from total portfolio cost, by vintage to produce indifference amounts.
- Indifference amount is allocated to rate groups for purposes of rate design based on top-100 hours method. Groups who contribute proportionately more to the system peak receive a higher allocation.
- Indifference rates, by rate group, are calculated based on total energy for each group (bundled, DA, CCA).

Load Shape Weighting of the MPB Already Accounted for in Allocation of Above Market Costs

- Existing method
  - MPB reflects unweighted average (flat profile) of annual forward prices
  - Generation portfolio cost reflects system profile (relatively flat)
- Under the existing method, the indifference amount reflects the differential on a system basis between the total portfolio costs and the market value of the portfolio.
  - This approach correctly develops an indifference amount for ALL customers.
- The allocation of above-market costs to rate groups (based on each group's contribution to the system peak) accounts for the load profiles of the different types of customers.
  - The existing method correctly produces lower indifference amounts for rate groups with proportionately lower consumption of peak resources, consistent with rate design of generation charges for bundled customers.
- If load profile weighting of the MPB is incorporated the appropriate load shape would be the generation profile, consistent with the profile underlying the total portfolio cost.

Modify TBS Price Consistent with MBP Modifications

- Existing TBS
  - Reflects day-ahead market prices for energy
  - Includes load-related CAISO charge types
  - Weighted to reflect applicable customer class profile
- Proposed modification:
  - Adjust TBS to be consistent with MPB modifications to reflect additional costs incurred by IOU in procuring energy and capacity for TBS customers (based on current year vintage calculations):
    - CAISO charges consistent with adjustments made to total portfolio
    - Market energy scaled consistent with renewable value adder

      Energy Scalar = (energy at market / energy at revised MPB)
    - Market energy scaled consistent with RA/capacity adder

      Capacity Scalar = (energy at market / market energy plus capacity)

Other CRS Issues for Consideration

- SCE supports the need for resolution of the CTC / PCIA issue raised by PG&E.
- Designation of PCIA-URG and PCIA-DWR needs to be reconsidered given impending elimination of DWR generation from total portfolios and the incorrect classification of "New Gen" above-market costs as DWR.
  - Distinction can be eliminated with no impact in ratemaking or cost responsibility.
- Address potential issue with "continuous DA" customers and new world generation created in D.08-09-012.
- Potential Method for Reflecting Value of "Provider of Last Resort" (POLR) Service provided by IOU's.
  - No proposal at this time.
  - Need for a POLR proposal is a function of outcome on switching rules, TBS, ESP financial security requirement and minimum BPS stay.

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Presentation 7

Switching Rules for CCA Programs

Marin Energy Authority

December 15, 2010

Switching rules should not apply to CCA customers

* CPUC decisions related to DA customers were made at a time when no CCA programs existed in CA
* IOU's have other mechanisms in place to protect bundled customers from any departing CCA load
* Past actions by the IOU in Marin have compromised CCA customer decision-making
* Technical problems caused by the IOU in Marin have impacted and continue to impact CCA customer decision-making
* Switching rules encourage non-cooperative behavior

Prior CPUC decisions were made in advance of CCA implementation

* No CCA program existed when switching rules were established, thus, potential impacts on CCA programs were unknown
* Switching rules for DA are now being reevaluated – considering CCA switching rules on a parallel track seems appropriate
* Prior CPUC decisions were made at a time when IOU cooperation with CCA efforts was anticipated
* CCAs are currently engaged in implementation activities

3-year retention rule is arbitrary & duplicative

* Outside CA, there is no 3-year retention rule benefiting the incumbent utility or the CCA
* Lack of symmetry: Inside CA, there is no 3-year retention rule benefiting CCA programs – only the IOUs
* MEA uses other strategies to manage load/resource balances without limiting customer choice
* IOUs in CA already have measures in place to protect against departing load (PCIA, etc.)
* CCA customers are small residential and small business consumers, so load migration is easier to manage

Actions in Marin have impacted customer decision-making

* Marketing and customer communications
* Technical/implementation issues
* The 3-year retention rule limits customer choice

Presentation 8

JOINT PARTIES COUNTERPROPOSAL ON PCIA REFORM

1. **Energy Benchmark**

    a. **IOU Proposal**: Weight the Market Price Benchmark (MPB), before loss adjustment, based on the proportion of total energy in a portfolio supplied by RPS eligible renewable energy; exclude pre-2003 resources (legacy QFs price, which are priced at "avoided cost").

    b. Joint Parties Counter-Proposal:

    i. Weight the MPB by vintage, before loss adjustment, based upon the RPS-compliant content of the resources going into that vintage. Do not exclude renewable legacy QFs from the RPS-renewables fraction**.**

    ii. Use revised MPB methodology to establish CTC also.

2. Green Benchmark/adder

    a. **IOU Proposal**: "U.S. Dept. of Energy's survey of reported contract premiums for renewable energy in the Western U.S."

    b. **Joint Parties Counter-Proposal**: The Green Benchmark in year *n* would be calculated using the costs and volumes for RPS-compliant resources owned or contracted by the IOUs that are forecast to commence delivery in year *n* or that commenced delivery in year *n*-1. Thus, for the Green Benchmark in year *n:*

    i. Each IOU would identify all its owned and contracted RPS-resources that began delivery in year *n*-1 and those projected to begin delivery in year *n*.

    ii. The IOUs would provide to the Energy Division their forecast of costs and volumes for such resources included in the ERRA filing for year *n*. The cost of such resources shall be the projected revenue requirement in year *n* for each such resource.

    iii. The Energy Division calculates the projected average cost of power from those resources in year *n* by summing up all the costs and dividing by the sum of all the MWHs for all three IOUs. This could be verified by trusted non-market participant(s). This value would be the Green Benchmark for all three IOUs.

    iv. Phase into use of REC values to develop the Green Benchmark when such values are not depressed by regulatory restrictions on the use of RECs and an appropriate market is up and running and demonstrated to be robust/liquid/etc.

3. **Capacity Costs**

    a. **IOU Proposal**: Create a Market Value of Capacity (line 40 in the SCE spreadsheet) for each IOU by multiplying the CAISO's ICPM (as approved by FERC) by the net qualifying capacity (NQC) for the portfolio of that IOU. This is done on a vintaged basis, and includes the NQC of intermittent renewables. Note: as filed at FERC, the mechanism is no longer called "interim capacity procurement mechanism" or "ICPM.' Instead it is referred to just as "capacity procurement mechanism" or "CPM."

    b. **Joint Parties Counter-Proposal**: The IOUs' proposal may be acceptable subject to further review and explanation of the information provided that verifies the NQC for each IOU. The NQC calculation should be made public and vetted by Energy Division and an independent party to verify the accuracy of NQC used in the calculations.

4. **CAISO costs**

    a. **IOU Proposal**: Exclude CAISO costs from the TPC (Total Portfolio Cost).

    b. **Joint Parties Counter-Proposal**:

        i. Removing the CAISO costs from the TPC is acceptable, subject to verification by Energy Division and an independent party .

        ii. Include an adder for the price difference between the hub and the LAP. The adder would be calculated for each utility using hourly prices from the CAISO day-ahead market from the prior calendar year. The adder for the current year would be the average of hourly prices at the relevant Load Aggregation Point (PG&E, SCE or SDG&E) from the prior calendar year minus the average of hourly prices at the relevant Trading Hub (NP15 for PG&E and SP15 for SCE and SDG&E) from the prior calendar year.

5. **Include or exclude projections of short-term purchases in the TPC**

    a. **IOU Proposal:** PG&E reports that it excludes resources with a contract of less than a year in the Indifference Rate calculation (I.e., it excludes very short term contracts and projected spot purchases). SCE reports that it includes short-term purchases/sales in its TPC. The IOUs propose to use the PG&E approach going forward.

    b. **Joint Parties Counter-Proposal**: The IOU proposal may be acceptable subject to further review and support. In particular, the Joint Parties require more information on the magnitude of the short term purchases/sales and the impact they have on the indifference adjustment.

6. **Shaping of Brown Power Benchmark**

a. **IOU Proposal:** Weight the peak- and off-peak forwards according to the IOU's generation profile.

b. **Joint Parties Counter-Proposal**: The Joint Parties propose to weight the peak- and off-peak forwards according to the IOU's bundled load shape. This offers a reasonable balance between precision and workability. The Joint Parties are willing to consider the IOU proposal but require more information about how the generation profile would be calculated, and what is included. The Joint Parties are concerned the IOU proposal could be unnecessarily complicated, requiring for example, a vintaged shape.

7. <u>Other issues:</u>

- **T**he IOUs don't want to allow the PCIA to go negative. Joint Parties response: Do not agree.

- Update TBS rate to be consistent with MPB. Joint Parties response: Agree in principle.

- Resolution of PCIA issues dependent on acceptance of IOU position on other outstanding DA issues. Joint Parties response: Do not agree. Reform of the PCIA calculation does not and should not be linked to resolution of all other DA matters at issue in this proceeding. Nevertheless, Joint Parties note that a coalition of parties have previously submitted a specific proposal on switching rules, TBS rate, and minimum stay provisions that is not too far apart from the latest proposal of the IOUs. With respect to the financial security arrangements applicable to ESPs and CCAs, there is much less agreement, but the issue is set to be resolved through litigation. Specifically, a decision on the bond for CCAs is pending before the CPUC, and there is a ruling by the ALJ in this proceeding providing for the financial security requirements for ESPs to be briefed.

- Fix SCE's PCIA-DWR / PCIA-URG framework. Joint Parties response: Agree.

- Any other proposals which are not addressed in this response should be deemed rejected.

Direct Access Parties Comprehensive Proposal

Proposal for TBS/Switching Rules/Minimum Stay/Financial Security Working Groups
Presented at October 18, 2010 meeting
For Discussion Purposes Only

Supporters (referred to as "Joint Parties"):
- **Alliance for Retail Energy Markets**
- **BlueStar Energy**
- **California Large Energy Consumers Association**
- **California Manufacturers and Technology Association**
- **California State University**
- **Direct Access Customer Coalition**
- **Energy Users Forum**
- **School Project for Utility Rate Reduction**
- **Walmart**

I. Overview:

The purpose of this proposal is to build on areas of potential consensus with respect to switching restrictions, minimum stay provisions, applicability of TBS rate, and ESP financial security requirements, consistent with applicable statutes, including Section 394.25(e) of the Public Utilities code which reads as follows:

> (e) If a customer of an electric service provider or a community choice aggregator is involuntarily returned to service provided by an electrical corporation, any reentry fee imposed on that customer that the commission deems is necessary to avoid imposing costs on other customers of the electrical corporation shall be the obligation of the electric service provider or a community choice aggregator, except in the case of a customer returned due to default in payment or other contractual obligations or because the customer's contract has expired. As a condition of its registration, an electric service provider or a community choice aggregator shall post a bond or demonstrate insurance sufficient to cover those reentry fees. In the event that an electric service provider becomes insolvent and is unable to discharge its obligation to pay reentry fees, the fees shall be allocated to the returning customers.

Section II of this proposal provides definitions to key terms that are used in the proposal. Sections III through VII outlines the specific components of the proposal with respect to switching restrictions applicable to voluntary and involuntary returns of customers to utility service; the calculation mechanism for ESP financial security requirements; and comments about the TBS rate. Section VIII presents the underlying rationale for this proposal.

II. Defined Terms: For purposes of this proposal, the following are defined terms:

SB_GT&S_0015034

1. An ***involuntary return*** of a Direct Access customer to service from a Utility Distribution Company (UDC) has occurred when the UDC has initiated the DASR process to return a customer to UDC bundled service due to any of the following events:
   a. The Commission has revoked the ESP's registration.
   b. The ESP-UDC Agreement has been terminated.
   c. The ESP or its authorized CAISO Scheduling Coordinator ("SC") has defaulted on its CAISO SC obligations, such that the ESP is no longer has an appropriately authorized CAISO Scheduling Coordinator.
2. An ***involuntary return*** of a Direct Access customer to UDC bundled service has not occurred as a result of the following events:
   a. A customer's contract with an ESP has expired.
   b. An ESP discontinues service to a customer due to that customer's default under their service agreement with the ESP.
3. A ***voluntary return*** of a Direct Access customer to UDC bundled service has occurred under either of the following conditions:
   a. An ESP has ceased to serve a customer because the contract between the ESP and the customers has expired.
   b. A customer has given the utility six months notice that the customer intends to return to UDC bundled service.
4. ***Re-entry fees*** are the sum of (i) the difference between marginal portfolio costs incurred or benefits obtained by the UDC to serve a customer that has been involuntarily returned to UDC bundled service and the amounts collected from that customer for service during the first six months that a customer is on UDC bundled service after the involuntary return, and (ii) the administrative costs incurred by the UDC to enroll the customer into UDC bundled service. For clarity, Re-entry Fees are applicable with respect to the UDCs procurement plan and resource adequacy requirements, and are not applicable to any costs associated with transmission or distribution or other utility charges already paid by Direct Access customers.

III. Switching Restrictions Applicable to *voluntary return* customers:

1. ***Voluntary return*** customers must give six months notice before returning to utility service from Direct Access service.
2. If a ***voluntary return*** customer remains on Direct Access service for the full six month notice period, upon the customer's return to utility service at the end of the six month notice period, the customer will receive service under the applicable tariff.
3. A ***voluntary return*** customer that returns to utility service without six months notice because its contract with an ESP has expired, or the customer has otherwise terminated its current relationship with the ESP, and no new ESP service has been initiated, will be charged the TBS rate for utility service for six months.

4. During the first 60 days of the of the six month period that the customer is on TBS service (referred to as the safe harbor period), the ***voluntary return*** customer may leave utility service and return to Direct Access service by having an ESP submit a DASR for service that will begin no later than the first meter read after the end of the 60 day safe harbor period.
5. The ***voluntary return*** customer will be subject to the non-bypassable charge vintage that is applicable to its new Direct Access service, if the customer does not leave the UDC service within the safe harbor period. If the customer does leave UDC service within the safe harbor period, that customer will retain the non-bypassable charge vintage to which the customer was subject at the time of the voluntary return.
6. If the ***voluntary return*** customer has not elected new Direct Access service by the end of the safe harbor period, the remainder of the six month service on TBS service will be provided to the customer, after which time the customer will be returned to the applicable tariff, and will be subject to the minimum stay provisions.
7. A DASR may be submitted for a ***voluntary return*** customer to leave utility service at then end of the minimum stay as of (1) the first scheduled meter read date that is 5 days after the customer has provided notice to the utility that the customer intends to return, so long as that scheduled meter read date is after the end of the customer's minimum stay period, or (2) the date of a special on-time meter read that is agreed to by the UDC, ESP, and customer and is after the end of the customer's minimum stay period.

IV. Switching Restrictions Applicable to *Involuntary Return* Customers:

1. ***Involuntary return*** customers will pay the TBS rate for the first six months that they are on utility service after the involuntary return.
2. The ***involuntary return*** customer may notify the utility that it plans to return to Direct Access service any time during the first 60 days that it is on TBS service, and will then have the remainder of the six month period to return to Direct Access service by having an ESP submit a DASR for service that will begin no later than the first meter read after the end of the six month period.
3. An ***Involuntary return*** customer who leaves utility service within the six month period will retain the non-bypassable charge vintage to which it was subject at the time of the involuntary return.
4. If the ***involuntary return*** customer has not elected Direct Access service by the end of the six month period, the customer will have no further rights to retain its previous non-bypassable charge vintage, and at the end of the six month period will be returned to an applicable tariff service, and will be subject to the minimum stay provisions.
5. A DASR may be submitted for an ***involuntary return*** customer to leave utility service at the end of the customer's minimum stay as of (1) the first scheduled meter read date that is 5 days after the customer has provided notice to the utility that the

customer intends to return, so long as that scheduled meter read date is after the end of the customer's minimum stay period, or (2) the date of a special one-time meter read that is agreed to by the UDC, ESP, and customer and is after the end of the customer's minimum stay period.

V. **Minimum Stay Provisions:** The minimum stay for ***voluntary return*** customers will be 12 months, which begins at the end of the safe harbor period or when the customers returns to utility service after having given six months notice. The minimum stay for an ***involuntary return*** customer will be 12 months and will begin at the end of the six month TBS rate period.

Separate issue with respect to TBS service: The Joint Parties request that the working group consider a mechanism that would allow customers to remain on TBS at their election beyond the six month notice period, so as to preserve their option to return to Direct Access service beyond the safe harbor period without being subject to a minimum stay on UDC service. Any customer making such election would be required to do so during the safe harbor period and would be required to give the UDC six months notice before transitioning from TBS service to an applicable utility tariff.

VI. **ESP financial security requirements:** ESPs will be required to post financial security to the IOUs to cover expected re-entry fees for customers that are involuntarily returned to utility service, as the terms "involuntary return" and "re-entry fees" are defined above. The calculation of expected re-entry fees shall be based on the ESP expected load over a six month period multiplied by expected, reasonable differences between the TBS rate and market prices, plus estimated administrative fees to enroll the expected ESP load into utility service.

VII. **TBS Rate:** Modifications to the TBS rate to reflect Resource Adequacy, as proposed by the IOUs at the January 12 and 13 workshops, are acceptable. There must be further discussion of all CAISO charge codes and how those are reflected in the TBS rate.

VIII. **Rationale for this proposal:**

1. The PU code section 395.25(e) financial security requirements are intended to protect the IOUs' bundled customers from involuntary returns of Direct Access customers.
2. Statute does not require customers who are returned involuntarily to utility service to be returned immediately to an applicable bundled tariff.
3. The definition of voluntary and involuntary returns does not affect the level of the security requirement; it only becomes applicable with respect to the conditions under which the utility will be able to access the financial security.
4. Six months is sufficient time for utilities to adjust their portfolios to integrate involuntarily returned load.

5. Utility planning processes should be conducted under a presumption that the Direct Access cap will be full. Consistent with that assumption, there is no need for a long minimum stay because customers are going to be only able to leave utility service when there are temporary opening in an existing cap or expansion of the cap.
6. Because any customer who departs utility service after the one year period will be assuming responsibility for exit fees based on the then current applicable vintage, bundled customers are not exposed to increased costs as a result of customers leaving utility service, so there is no need for a multi-month notice period for customers to leave utility service.

SDG&E Data Response

DATA RQUEST ED-01
R.07-05-025
DIRECT ACCESS
DATE RECEIVED : DECEMBER 14, 2010
DATE RESPONDED : DECEMBER 21, 2010

QUESTION 1

Provide the average cost of renewables in the IOU portfolio based on 2009 FERC Form #1 generation resource information.

SDG&E Response 1

Based on SDG&E's 2009 FERC Form 1 purchase power data, the average cost for 2009 renewable delivered energy is $61.91. See attached spreadsheet, DirectAccessReopeningOIR_DR_ED_001-Q01SDGE.xls.

DirectAcessReopenin
gOIR_DR_ED_001_Q

Name of Company or Public Authority	MWHs Purchased	Capacity Pay ($)	Energy Pay ($)	Total ($)	Avg. Price ($/MWH)
RENEWABLE BILATERAL CONTRACTS (Excluding REC only purchases):					
City of San Diego (Pt. Loma Renewable)	13,425		1,014,918	1,014,918	
Covanta Delano Inc	361,710		24,605,914	24,605,914	
Covanta Otay 3	24,659		1,319,379	1,319,379	
Covanta Otay 1	5,839		589,304	589,304	
Fortistar Renewables GP LLC Miramar	29,978		1,578,171	1,578,171	
Fortistar Renewables GP LLC North City	4,413		231,851	231,851	
Fortistar Renewables GP LLC Prima Deshecha	39,995		1,996,427	1,996,427	
FPL Energy Green Power Wind LLC	33,249		1,746,691	1,746,691	
Gas Recovery Systems Coyote Canyon	50,447		2,710,224	2,710,224	
Gas Recovery Systems Sycamore Canyon	11,570		627,723	627,723	
Iberdola Renewables	86,601		4,311,756	4,311,756	
Kumeyaay Wind LLC	143,027		7,308,578	7,308,578	
Oasis Power Partners LLC	156,244		7,697,720	7,697,720	
PacifiCorp	441,153		31,317,745	31,317,745	
San Diego County Water Authority	20,213		1,035,376	1,035,376	
Co-generation (renewables only)	28,112	459,169	1,251,963	1,711,132	
Subtotal	**1,450,635**	**459,169**	**89,343,740**	**89,802,909**	**61.91**

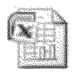
DATA RQUEST ED-01
R.07-05-025
DIRECT ACCESS
DATE RECEIVED : DECEMBER 14, 2010
DATE RESPONDED : DECEMBER 21, 2010

QUESTION 2

Provide, in spreadsheet form, calculations demonstrating the inclusion of modifications reflected in the Joint IOU proposal for revising the Indifference Rate calculations.

SDG&E Response 2:

See attached spreadsheet, DirectAccessReopeningOIR_DR-ED_001-Q2&5.xls
in the "2010 benchmark – response to 2" tab for illustrative calculations reflecting the inclusion of Joint IOU proposed modifications to the determination of Indifference revenues.



DirectAccessReopeni
ngOIR_DR_ED_001-(

		Proposed Method
		SP15
		SDG&E
October 1 through October 31	**Avg On-peak Price**	**$59.41**
October 1 through October 31	**Avg Off-peak Price**	**$41.02**
2010		
Total Portfolio Generation (MWh)	17,003,346	
On Peak Generation (MWh)	11,701,815	
Off Peak Generation (MWh)	5,301,531	
On Peak Weight	69%	
Off Peak Weight	31%	
Calculated Baseload Price ($/MWh)		**$53.68**
RPS %	12%	
Renewable Premium	$ 20.00	
Adjusted MPB		**$ 56.08**
Adjust for Line Losses		1.043
Adjusted MPB (inc. Line Losses)		**$ 58.49**
Market Value of Energy Portfolio ($)	$ 994,528,293	
NQC (MW)	4,314	
Capacity Adder ($/kw-yr)	$ 41.00	
Market Value of Capacity Portfolio ($)	$ 176,868,260	

	Proposed Method	
		SP15
		SDG&E
October 1 through October 31	**Avg On-peak Price**	**$59.41**
October 1 through October 31	**Avg Off-peak Price**	**$41.02**
2010		
Total Portfolio Generation (MWh)	17,003,346	
On Peak Generation (MWh)	11,701,815	
Off Peak Generation (MWh)	5,301,531	
On Peak Weight	69%	
Off Peak Weight	31%	
Calculated Baseload Price ($/MWh)		**$53.68**
RPS %	0%	
Renewable Premium	$ -	
Adjusted MPB		**$ 53.68**
Adjust for Line Losses		1.043
Adjusted MPB (inc. Line Losses)		**$ 55.99**
Market Value of Energy Portfolio ($)	$ 951,965,516	
NQC (MW)	4,314	
Capacity Adder ($/kw-yr)	$ 41.00	
Market Value of Capacity Portfolio ($)	$ 176,868,260	

DATA RQUEST ED-01
R.07-05-025
DIRECT ACCESS
DATE RECEIVED : DECEMBER 14, 2010
DATE RESPONDED : DECEMBER 21, 2010

QUESTION 3

Provide data relevant to the issue of the exemptions identified for "continuous DA" customers in D.08-09-012.

SDG&E Response 3:

This issue does not apply to SDG&E. Please see Schedule DA-CRS which has a category for "New Non-Continuous DA customers" as approved in Advice Letter 2166-E from D.10-04-010.

http://www.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_DA-CRS.pdf

DATA RQUEST ED-01
R.07-05-025
DIRECT ACCESS
DATE RECEIVED : DECEMBER 14, 2010
DATE RESPONDED : DECEMBER 21, 2010

QUESTION 4

Provide preliminary scalars used for revision of the existing Transitional Bundled Service (TBS) rate consistent with proposed changes to the indifference rate calculation as discussed in response to question #2.

SDG&E Response 4:

The scalers are embedded within the calculations for the response to question 2.

DATA RQUEST ED-01
R.07-05-025
DIRECT ACCESS
DATE RECEIVED : DECEMBER 14, 2010
DATE RESPONDED : DECEMBER 21, 2010

QUESTION 5

Provide an estimate of the impact on the existing indifference rate calculation of removing renewable generation resources from the total portfolio.

SDG&E Response 5:

Please see spreadsheet in response 2, "2010 benchmarks –response to 5" tab for an estimation of the impact of removing renewable generation resources from the determination of indifference revenues.

Southern California Edison Data Response

SOUTHERN CALIFORNIA EDISON COMPANY
Rulemaking 07-05-025
Data Response

SCE Data Request No.:	ED_001-01		
Request Date:	December 14, 2010	Requester DR No.:	ED_DR001
Date Sent:	December 17, 2010	Requesting Party:	Steve Roscow, Energy Division
SCE Witness:	James Schichtl		

QUESTION 1

Provide the average cost of renewables in the IOU portfolio based on 2009 FERC Form #1 generation resource information.

ANSWER 1

Based on SCE's 2009 FERC Form 1 purchase power data, the average cost for 2009 renewable generation resources is $82.09 (energy and capacity costs combined). Isolating energy costs only, the average cost for 2009 renewable generation resources is $61.75. See attached Excel spreadsheet titled "SCE FERC Form 1 Data – Renewable Generation Resources".

SOUTHERN CALIFORNIA EDISON COMPANY
Rulemaking 07-05-025
Data Response

SCE Data Request No.:	ED_001-01		
Request Date:	December 14, 2010	Requester DR No.:	ED_DR001
Date Sent:	December 17, 2010	Requesting Party:	Steve Roscow, Energy Division
SCE Witness:	James Schichtl		

QUESTION 2

Provide, in spreadsheet form, calculations demonstrating the inclusion of modifications reflected in the Joint IOU proposal for revising the Indifference Rate calculations.

ANSWER 2

See attached spreadsheet titled "DA OIR Workshop – IR Proposal Worksheet". Inputs and assumptions provided in the worksheet and incorporated in the revised indifference rate calculation are illustrative and subject to update.

Revision – Original version (12/17) has been updated to reflect SCE's generation profile, and to directly reference the DOE report on renewable premiums, included on tab "DOE Renewable Premium."

SOUTHERN CALIFORNIA EDISON COMPANY
Rulemaking 07-05-025
Data Response

SCE Data Request No.:	ED_001-01		
Request Date:	December 14, 2010	Requester DR No.:	ED_DR001
Date Sent:	December 17, 2010	Requesting Party:	Steve Roscow, Energy Division
SCE Witness:	James Schichtl		

QUESTION 3

Provide data relevant to the issue of the exemptions identified for "continuous DA" customers in D.08-09-012.

ANSWER 3

Based on historical data as of November 2010, SCE currently has 908 non-Residential customers identified as "continuous DA", as defined. Of these, 862 currently are served on direct access and are identified having original vintage (i.e., have never returned to bundled service). The remaining 46 customers receive bundled portfolio service. Of these, a single customer is accepted to return to DA under the SB 695 reopening and will now be identified as a 2010 vintage customer for purposes of CRS (and maintain their continuous DA designation).

Continuous DA Customers as of Nov 2010

Rate Class	DA Accounts		Bundled Accounts		Total Continuous DA	
	Number	kWh	Number	kWh	Number	kWh
Nonres	862	186,876,513	46	11,218,953	908	198,095,466
Res	7,078	61,179,923	9,800	86,681,315	16,878	147,861,238
Total	7,940	248,056,436	9,846	97,900,268	17,786	345,956,704

SOUTHERN CALIFORNIA EDISON COMPANY
Rulemaking 07-05-025
Data Response

SCE Data Request No.:	ED_001-01		
Request Date:	December 14, 2010	Requester DR No.:	ED_DR001
Date Sent:	December 17, 2010	Requesting Party:	Steve Roscow, Energy Division
SCE Witness:	James Schichtl		

QUESTION 4

Provide preliminary scalars to be used for revision of the existing Transitional Bundled Service (TBS) rate consistent with proposed changes to the indifference rate calculation as discussed in response to question #2.

ANSWER 4

See the attached spreadsheet titled “DA OIR Workshop – IR Proposal Worksheet”, tab “IOU Spreadsheet”, line 72.

SOUTHERN CALIFORNIA EDISON COMPANY
Rulemaking 07-05-025
Data Response

SCE Data Request No.:	ED_001-01		
Request Date:	December 14, 2010	Requester DR No.:	ED_DR001
Date Sent:	December 17, 2010	Requesting Party:	Steve Roscow, Energy Division
SCE Witness:	James Schichtl		

QUESTION 5

Provide an estimate of the impact on the existing indifference rate calculation of removing renewable generation resources from the total portfolio.

ANSWER 5

The table included below shows the reduction and percentage reduction to estimated indifference rates for all vintages in 2011.

Indifference Rate ($/MWh)	Excluding Renewables	Including Renewables	Change	% Change
2001/2002	11.01	15.88	(4.87)	-31%
2003	11.01	15.88	(4.87)	-31%
2004	11.01	15.88	(4.87)	-31%
2005	11.01	15.88	(4.87)	-31%
2006	12.88	17.60	(4.72)	-27%
2007	15.02	20.16	(5.14)	-25%
2008	16.12	21.28	(5.16)	-24%
2009	19.09	24.70	(5.61)	-23%
2010	20.23	26.57	(6.34)	-24%
2011	21.13	29.25	(8.12)	-28%

Southern California Edison Company

Illustrative Vintaged Indifference Rate Calculation - 2011 Forecast Year

	Vintage Year									
Proposed IR Calculation	2001	2003	2004	2005	2006	2007	2008	2009	2010	2011
Supply (GWhs)	53,525	53,525	53,525	53,528	59,566	61,884	65,551	67,969	71,967	74,524
Supply At Cust Meter (GWhs)	50,831	50,831	50,831	50,834	56,568	58,769	62,252	64,548	68,345	70,773
Total Portfolio Cost ($000)	3,697,410	3,697,410	3,697,410	3,697,580	4,107,458	4,428,221	4,686,952	5,085,296	5,419,965	5,738,761
ISO Load-Related Costs ($000)	71,823	71,823	71,823	71,827	79,929	83,039	87,960	91,204	96,569	100,000
Revised Portfolio Cost ($000)	3,625,587	3,625,587	3,625,587	3,625,753	4,027,529	4,345,182	4,598,992	4,994,092	5,323,396	5,638,761
Market Price Benchmark ($/MWh)	49.22	49.22	49.22	49.22	48.88	49.41	49.28	49.45	49.64	50.05
Market Value of Portfolio ($000)	2,634,642	2,634,642	2,634,642	2,634,787	2,911,728	3,057,793	3,230,107	3,360,800	3,572,811	3,729,999
Vintaged Above Market Cost ($000)	990,945	990,945	990,945	990,966	1,115,801	1,287,389	1,368,885	1,633,292	1,750,585	1,908,762
Total System Sales (GWhs)	85,111	85,111	85,111	85,111	85,111	85,111	85,111	85,111	85,111	85,111
System Avg. Indifference Rate ($/MWh)	11.64	11.64	11.64	11.64	13.11	15.13	16.08	19.19	20.57	22.43

Forward Strip Price (On Peak) - $/MWh										40.58
Forward Strip Price (Off Peak) - $/MWh										28.17
Generation Energy Portfolio										
On-Peak										65%
Off-Peak										35%
Weighted MPB - $/MWh	36.24	36.24	36.24	36.24	36.24	36.24	36.24	36.24	36.24	36.24
Simple Average MPB - $/MWh	35.27	35.27	35.27	35.27	35.27	35.27	35.27	35.27	35.27	35.27
Renewable Supply (GWhs)	8,998	8,998	8,998	8,998	8,998	10,990	11,195	12,187	13,621	15,621
Renewable %	16.8%	16.8%	16.8%	16.8%	15.1%	17.8%	17.1%	17.9%	18.9%	21.0%
Renewable Premium ($/MWh)										19.96
Market Value of RPS Energy ($000)	505,682	505,682	505,682	505,682	505,682	617,632	629,153	684,902	765,492	877,891
Market Value of Non-RPS Energy ($000)	1,613,633	1,613,633	1,613,633	1,613,747	1,832,557	1,844,358	1,969,841	2,021,507	2,114,433	2,134,607
Capacity Procurement (MW-Months)	150,827	150,827	150,827	150,836	167,850	174,381	184,716	191,529	202,796	210,000
CPM ($/MW)										41.00
Market Value of Capacity ($000)	515,327	515,327	515,327	515,357	573,489	595,803	631,114	654,391	692,885	717,500
Market Value of Portfolio ($000)	2,634,642	2,634,642	2,634,642	2,634,787	2,911,728	3,057,793	3,230,107	3,360,800	3,572,811	3,729,999

Proposed Indifference Rate ($/MWh)	2001	2003	2004	2005	2006	2007	2008	2009	2010	2011
Domestic	13.78	13.78	13.78	13.78	15.52	17.91	19.04	22.72	24.35	26.55
TC-1	14.35	14.35	14.35	14.35	16.16	18.65	19.83	23.66	25.36	27.65
GS-1	10.40	10.40	10.40	10.40	11.71	13.51	14.36	17.14	18.37	20.03
GS-2	14.63	14.63	14.63	14.63	16.47	19.00	20.21	24.11	25.84	28.17
TOU-GS-3	7.08	7.08	7.08	7.08	7.98	9.20	9.78	11.67	12.51	13.64
TOU-8-Sec	10.47	10.47	10.47	10.47	11.79	13.61	14.47	17.26	18.50	20.17
TOU-8-Pri	9.63	9.63	9.63	9.63	10.84	12.51	13.30	15.87	17.01	18.55
TOU-8-Sub	7.59	7.59	7.59	7.59	8.55	9.86	10.49	12.51	13.41	14.63
PA-1	12.63	12.63	12.63	12.63	14.22	16.40	17.44	20.81	22.30	24.32
PA-2	7.87	7.87	7.87	7.87	8.87	10.23	10.88	12.98	13.91	15.17
TOU-PA	5.58	5.58	5.58	5.58	6.29	7.25	7.71	9.20	9.86	10.76
TOU-PA-5	11.15	11.15	11.15	11.15	12.55	14.48	15.40	18.37	19.69	21.47
St Lighting	0.04	0.04	0.04	0.04	0.05	0.06	0.06	0.07	0.08	0.09

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
2									2009 FERC FORM 1 PAGES 326 - 327								
3				Name of Company or Public Authority	Stat	Ferc Rate	Avg.	Actual Demand (MWH)		MWH	Power Exchanges		Cost / Settlement of Power				
4				(Footnote Affiliations)	Class	Sched No.	Mo. Bill	Avg. Mo.	Avg. Mo.	Purchased	MWH	MWH	Demand	Energy	Other		Total
5							Demand	NCP Dmd	CP Dmd		Received	Delivered	($)	($)	($)		($)
6	Page	Line #	QFID #	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)		(m)
7																	
8			6111	AES TEHACHAPI NORTHWIND	OS4		N/A			9,326	-	-	119,722.39	393,844.19	-		513,566.58
9			6043	AES TEHACHAPI WIND (85-A)	OS4		N/A			21,074	-	-	261,693.52	850,226.25	-		1,111,919.77
10			6044	AES TEHACHAPI WIND (85-B)	OS4		N/A			28,866	-	-	454,726.73	1,180,807.05	-		1,635,533.78
11			6040	AES TEHACHAPI WIND (VG 2)	OS4		N/A			11,528	-	-	116,079.67	471,765.72	-		587,845.39
12			6041	AES TEHACHAPI WIND (VG 3)	OS4		N/A			10,104	-	-	120,220.79	426,325.53	-		546,546.32
13			6042	AES TEHACHAPI WIND (VG 4)	OS4		N/A			9,380	-	-	105,643.93	381,577.70	-		487,221.63
14			6039	AES TEHACHAPI WIND (VG I)	OS4		N/A			13,074	-	-	128,360.92	543,802.46	-		672,163.38
15			6090	ALTA MESA PWR PUR CONTRCT	OS4		N/A			67,912	-	-	1,799,172.02	2,660,565.14	-		4,459,737.16
16			4137	AMERICAN ENERGY INC.	OS1		N/A			789	-	-	3,222.04	28,713.55	-		31,935.59
17			4030	BATES, DANIEL M, ET AL	OS4		N/A			458	-	-	11,378.59	22,153.58	-		33,532.17
18			6213	BNY WESTERN TRUST CO	OS2		N/A			31,479	-	-	338,115.18	1,954,981.11	-		2,293,096.29
19			6011	BOX CAR I PPCT	OS4		N/A			11,878	-	-	199,232.28	489,936.45	-		689,168.73
20			6097	BOX CAR II PPCT	OS4		N/A			20,374	-	-	397,883.55	851,159.91	-		1,249,043.46
21			4152	CALLEGUAS MUN WTR DIST	OS2		N/A			765	-	-	2,793.19	27,332.71	-		30,125.90
22			4010	CALLEGUAS MWD 1-CONEJO	OS4		N/A			21	-	-	1,704.01	(385.15)	-		1,318.86
23			4022	CALLEGUAS MWD 2-CHATSWRTH	OS4		N/A			6,660	-	-	144,572.09	271,429.25	-		416,001.34
24			4052	CALLEGUAS MWD 3-SNTA ROSA	OS4		N/A			398	-	-	14,617.45	15,024.61	-		29,642.06
25			6060	CALWIND RESOURCES INC	OS4		N/A			15,850	-	-	288,801.69	665,298.00	-		954,099.69
26			6236	CALWIND RESOURCES INC	OS1		N/A			52,289	-	-	92,161.01	2,107,970.30	-		2,200,131.31
27			1133	CAMBRIAN ENERGY WOODVILLE	OS2		N/A			1,274	-	-	574.58	58,398.55	-		58,973.13
28			6057	CAMERON RIDGE LLC III	OS2		N/A			142,205	-	-	2,535,629.72	8,807,507.64	-		11,343,137.36
29			6091	CAMERON RIDGE LLC IV	OS4		N/A			37,753	-	-	679,742.28	2,336,444.20	-		3,016,186.48
30			4034	CENTRAL HYDRO/ISABELLA	OS4		N/A			12,760	-	-	746,231.52	480,285.21	-		1,226,516.73
31			4054	CITY OF SANTA ANA	OS3		N/A			-	-	-	4.08	(112.72)	-		(108.64)
32			1038	COLMAC ENERGY INC	OS2		N/A			355,159	-	-	10,234,868.18	22,221,870.78	-		32,456,738.96
33			6055	CORAM ENERGY GROUP LTD	OS4		N/A			11,714	-	-	103,466.39	480,570.47	-		584,036.86
34			6029	CORAM ENERGY LLC	OS2		N/A			29,793	-	-	49,378.85	1,213,799.72	-		1,263,178.57
35			3030	COSO ENERGY DEVELOPERS	OS2		N/A			506,441	-	-	12,333,497.79	31,729,759.54	-		44,063,257.33
36			3008	COSO FINANCE PARTNERS	OS2		N/A			599,842	-	-	13,092,596.40	37,509,060.01	-		50,601,656.41
37			3029	COSO POWER DEVELOPERS	OS2		N/A			560,925	-	-	13,526,263.09	35,088,914.42	-		48,615,177.51
38			2804	COUNTY SAN. DIS. OF O.C.	OS4		N/A			(251)	-	-	(24.50)	(17,346.13)	-		(17,370.63)
39			6089	CTV PPCT	OS4		N/A			30,200	-	-	539,073.28	1,170,246.16	-		1,709,319.44
40			5010	CURTIS, EDWIN	OS3		N/A			4	-	-	0.35	211.27	-		211.62
41			4071	DEEP SPRINGS COLLEGE	OS3		N/A			8	-	-	3.26	356.04	-		359.30
42			3004	DEL RANCH, LTD/NILAND 2	OS2		N/A			344,714	-	-	8,056,443.38	21,562,361.56	-		29,618,804.94
43			4008	DESERT POWER CO	OS2		N/A			1,231	-	-	4,168.49	49,974.37	41,645.13	(7)	95,787.99
44			4025	DESERT WATER AGCY/WHTEWTR	OS4		N/A			916	-	-	31,724.91	30,219.58	-		61,944.49
45			6063	DESERT WIND I PPCT	OS4		N/A			80,454	-	-	1,539,723.15	4,927,192.34	-		6,466,915.49
46			6113	DESERT WIND II PPCT	OS4		N/A			206,913	-	-	3,888,271.11	12,400,756.02	-		16,289,027.13
47			6114	DESERT WIND III PPCT	OS4		N/A			81,176	-	-	1,738,100.63	4,992,970.56	-		6,731,071.19
48			4026	DESERT WTR AGCY/SNOWCREEK	OS4		N/A			524	-	-	12,703.55	20,755.15	-		33,458.70
49			6053	DIFWIND FARMS LTD V	OS4		N/A			14,255	-	-	330,843.73	549,267.48	-		880,111.21
50			6088	DIFWIND PARTNERS LTD	OS4		N/A			29,093	-	-	596,504.99	1,086,801.15	-		1,683,306.14
51			6305	DILLON WIND LLC	OS		N/A			155,228	-	-	-	9,265,457.68	-		9,265,457.68
52			6095	DUTCH ENERGY	OS4		N/A			21,124	-	-	585,398.17	813,626.27	-		1,399,024.44
53			6056	EDOM HILLS PROJECT 1	OS4		N/A			31,741	-	-	410,041.47	1,928,698.10	-		2,338,739.57
54			3009	ELMORE, LTD/NILAND 3	OS2		N/A			332,207	-	-	8,032,231.05	20,769,058.46	-		28,801,289.51
55			6062	ENERGY DEV & CONSTR CORP	OS4		N/A			33,608	-	-	552,555.48	1,347,819.50	-		1,900,374.98
56			6031	EUI MANAGEMENT PH, INC.	OS4		N/A			49,406	-	-	1,098,434.35	3,055,792.40	-		4,154,226.75
57			6004	FPL ENERGY CABAZON WIND	OS4		N/A			84,198	-	-	1,136,036.58	5,256,091.38	-		6,392,127.96
58			1005	GENERATING RES REC PTNRS	OS2		N/A			12,637	-	-	25,945.44	542,939.83	-		568,885.27
59			3107	GEYSERS POWER CO LLC QFID	OS2		N/A			1,971,000	-	-	-	102,297,962.57	-		102,297,962.57
60			4055	GOLETA WATER DISTRICT	OS3		N/A			117	-	-	1,086.70	3,648.25	-		4,734.95
61			3001	HEBER GEOTHERMAL CO	OS2		N/A			367,510	-	-	6,778,305.96	22,956,018.72	-		29,734,324.68
62			4006	HENWOOD ASSOC/MILLNER CR	OS2		N/A			780	-	-	13,396.97	39,157.84	-		52,554.81

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
2									2009 FERC FORM 1	PAGES 326 - 327							
3				Name of Company or Public Authority	Stat	Ferc Rate	Avg.	Actual Demand (MWH)		MWH	Power Exchanges		Cost / Settlement of Power				
4				(Footnote Affiliations)	Class	Sched No.	Mo. Bill	Avg. Mo.	Avg. Mo.	Purchased	MWH	MWH	Demand	Energy	Other		Total
5							Demand	NCP Dmd	CP Dmd		Received	Delivered	($)	($)	($)		($)
6	Page	Line #	QFID #	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)		(m)
7																	
63			4004	HI HEAD HYDRO, INC	OS2		N/A			1,944	-	-	28,142.65	116,614.38	-		144,757.03
64			1209	IMPERIAL VALLEY RES RECOV	OS2		N/A			60,975	-	-	-	4,452,252.99	(272,040.00)	(50)	4,180,212.99
65			1099	INLAND EMPIRE UTIL AGNCY	OS1		N/A			1,379	-	-	2,426.53	61,138.07	-		63,564.60
66			4017	IRVINE RANCH WATER DIST	OS2		N/A			(71)	-	-	(9.46)	(4,936.10)	-		(4,945.56)
67			4039	KAWEAH RIVER POWER AUTH	OS4		N/A			35,096	-	-	1,698,774.98	1,332,213.80	-		3,030,988.78
68			1009	L A CO SAN #2 (P HILLS A)	OS1		N/A			5,296	-	-	12,231.98	330,854.33	-		343,086.31
69			1090	L A CO SAN #2 (P HILLS B)	OS2		N/A			365,409	-	-	9,505,097.94	22,976,877.03	-		32,481,974.97
70			1082	L A CO SAN #2 (P VERDES)	OS2		N/A			(1,202)	-	-	(4,647.37)	(74,202.66)	-		(78,850.03)
71			1077	L A CO SAN #2 (SPADRA)	OS2		N/A			43,724	-	-	1,313,486.25	2,766,321.11	-		4,079,807.36
72			4029	LA CO FLOOD CONTROL DIST	OS4		N/A			4,254	-	-	233,710.81	169,703.85	-		403,414.66
73			3026	LEATHERS, L P (NILAND 4)	OS2		N/A			331,668	-	-	7,506,221.43	20,757,015.09	-		28,263,236.52
74			4028	LOWER TULE RIVER IRRIG	OS4		N/A			1,141	-	-	31,323.94	41,252.91	-		72,576.85
75			5017	LUZ SOLAR PARTNERS III	OS2		N/A			84,441	-	-	5,065,210.46	5,415,216.01	-		10,480,426.47
76			5018	LUZ SOLAR PARTNERS IV	OS2		N/A			83,412	-	-	5,052,331.81	5,339,423.74	-		10,391,755.55
77			5051	LUZ SOLAR PARTNERS IX	OS2		N/A			200,488	-	-	17,616,715.86	13,004,986.62	-		30,621,702.48
78			5019	LUZ SOLAR PARTNERS V	OS2		N/A			78,343	-	-	5,325,445.85	5,002,634.85	-		10,328,080.70
79			5020	LUZ SOLAR PARTNERS VI	OS2		N/A			93,379	-	-	5,886,554.02	6,052,190.04	-		11,938,744.06
80			5021	LUZ SOLAR PARTNERS VII	OS2		N/A			90241	-	-	5,790,237.88	5,861,590.39	-		11,651,828.27
81			5050	LUZ SOLAR PARTNERS VIII	OS2		N/A			191,510	-	-	15,557,119.88	12,463,812.49	-		28,020,932.37
82			3003	MAMMOTH PACIFIC #1	OS2		N/A			44,941	-	-	837,625.78	2,806,500.36	-		3,644,126.14
83			3027	MAMMOTH PACIFIC #2	OS4		N/A			94,500	-	-	1,897,337.00	5,847,956.84	-		7,745,293.84
84			3018	MAMMOTH PACIFIC L.P. I	OS2		N/A			103,903	-	-	2,157,849.31	6,444,449.29	-		8,602,298.60
85			6308	MESA WIND POWER CORP	OS1		N/A			58,178	-	-	114,991.22	2,305,624.58	-		2,420,615.80
86			1210	MM TAJIGUAS ENERGY LLC 1	OS2		N/A			23,254	-	-	-	1,703,960.81	-		1,703,960.81
87			6006	MOGUL WIND PARTNERSHIP I	OS1		N/A			9,506	-	-	-	723,616.05	-		723,616.05
88			4147	MONTE VISTA WATER DIST	OS1		N/A			57	-	-	151.40	341.46	-		492.86
89			4051	MONTECITO WATER DIST	OS4		N/A			563	-	-	16,907.19	22,783.75	-		39,690.94
90			4031	MOSS, RICHARD	OS4		N/A			390	-	-	7,842.79	16,001.96	-		23,844.75
91			4107	MWD CORONA	OS2		N/A			18,515	-	-	-	1,729,028.47	-		1,729,028.47
92			4108	MWD RED MOUNTAIN	OS2		N/A			15,272	-	-	-	1,304,668.63	-		1,304,668.63
93			4106	MWD TEMESCAL	OS2		N/A			18,437	-	-	-	1,719,540.72	-		1,719,540.72
94			4105	MWD VENICE	OS2		N/A			9,855	-	-	-	1,219,238.27	-		1,219,238.27
95			6052	NAWP INC.(EAST WINDS PRO)	OS4		N/A			7,944	-	-	152,477.20	309,761.32	-		462,238.52
96			6234	OAK CREEK ENGY SYS INC II	OS1		N/A			79,564	-	-	1,696,271.59	4,945,019.70	-		6,641,291.29
97			3104	ORMESA GEOTHERMAL 1 # 310	OS2		N/A			435,237	-	-	8,492,352.58	27,140,008.80	-		35,632,361.38
98			3108	ORNI 18, LLC	OS2		N/A			29,449	-	-	-	2,454,362.54	-		2,454,362.54
99			6338	PACIFICORP	OS2		N/A			110,354	-	-	-	7,567,864.30	-		7,567,864.30
100			6112	PAINTED HILLS WIND DEV	OS4		N/A			36,904	-	-	468,022.34	2,278,275.58	-		2,746,297.92
101			6335	PUGET SOUND ENERGY	OS2		N/A			500,000	-	-	-	50,004,483.44	-		50,004,483.44
102			6024	RIDGETOP ENERGY, LLC I	OS4		N/A			154,239	-	-	2,743,493.42	6,169,232.96	-		8,912,726.38
103			6092	RIDGETOP ENERGY, LLC II	OS4		N/A			80,769	-	-	2,070,031.06	5,608,008.33	-		7,678,039.39
104			1225	RIVERSIDE CTY WASTE MGMT	OS4		N/A			3,945	-	-	-	452,360.03	-		452,360.03
105			1007	ROYAL FARMS	OS3		N/A			95	-	-	158.75	3,551.04	-		3,709.79
106			6136	S & L RANCH	OS3		N/A			-	-	-	-	(57.17)	-		(57.17)
107			3050	SALTON SEA IV	OS2		N/A			355,137	-	-	7,310,630.77	29,596,755.73	-		36,907,386.50
108			3039	SALTON SEA POWER GEN #1	OS2		N/A			81,648	-	-	2,238,297.45	7,600,536.64	-		9,838,834.09
109			3028	SALTON SEA POWER GEN #2	OS2		N/A			136,363	-	-	3,313,829.41	8,525,750.99	-		11,839,580.40
110			3025	SALTON SEA POWER GEN #3	OS2		N/A			391,368	-	-	9,594,411.37	24,496,620.74	-		34,091,032.11
111			4014	SAN BERNARDINO MWD 1	OS3		N/A			323	-	-	1,409.90	13,177.24	-		14,587.14
112			4100	SAN BERNARDINO MWD 3	OS3		N/A			181	-	-	95.92	6,569.42	-		6,665.34
113			6064	SAN GORGONIO FARMS, INC	OS2		N/A			54,819	-	-	527,295.23	2,078,341.11	-		2,605,636.34
114			6058	SAN GORGONIO WESTWINDS II	OS4		N/A			29,240	-	-	616,209.33	1,796,532.51	-		2,412,741.84
115			6009	SAN GORGONIO WIND FARMS	OS2		N/A			7,577	-	-	33,552.80	262,680.37	-		296,233.17
116			6087	SEC 16-29 TRUST -ALT III	OS4		N/A			80,619	-	-	1,664,850.14	2,997,739.85	-		4,662,589.99
117			3021	SECOND IMPERIAL GEO CO	OS2		N/A			246,066	-	-	6,918,307.53	15,477,338.41	-		22,395,645.94

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
2	2009 FERC FORM 1 PAGES 326 - 327																
3				Name of Company or Public Authority	Stat	Ferc Rate	Avg.	Actual Demand (MWH)		MWH	Power Exchanges		Cost / Settlement of Power				
4				(Footnote Affiliations)	Class	Sched No.	Mo. Bill	Avg. Mo.	Avg. Mo.	Purchased	MWH	MWH	Demand	Energy	Other		Total
5							Demand	NCP Dmd	CP Dmd		Received	Delivered	($)	($)	($)		($)
6	Page	Line #	QFID #	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)		(m)
7																	
118			6051	SECTION 20 TRUST	OS4		N/A			40,517	-	-	834,484.84	1,551,604.26	-		2,386,089.10
119			6094	SECTION 22 TRUST (SN JAC)	OS4		N/A			42,990	-	-	924,266.51	1,662,844.44	-		2,587,110.95
120			5233	SIERRRA SUNTOWER, LLC	OS1		N/A			90	-	-	556.66	4,572.59	-		5,129.25
121			6065	SKY RVR PTNRSHP-WILD I	OS4		N/A			77,876	-	-	1,235,639.62	4,790,443.47	-		6,026,083.09
122			6066	SKY RVR PTNRSHP-WILD II	OS4		N/A			42,194	-	-	577,968.41	2,580,417.43	-		3,158,385.84
123			6067	SKY RVR PTNRSHP-WILD III	OS4		N/A			44,068	-	-	487,939.97	2,693,884.51	-		3,181,824.48
124			5005	SUNRAY ENERGY, INC.	OS2		N/A			42,487	-	-	5,345,027.36	1,623,681.19	-		6,968,708.55
125			6037	TEHACHAPI PWR PUR TRUST	OS4		N/A			118,078	-	-	2,074,497.80	7,248,625.00	-		9,323,122.80
126			6105	TERRA-GEN 251 WIND X	OS4		N/A			10,168	-	-	136,701.02	396,759.71	-		533,460.73
127			6106	TERRA-GEN 251 WIND XI	OS4		N/A			8,830	-	-	124,650.22	335,732.75	-		460,382.97
128			6107	TERRA-GEN 251 WIND XII	OS4		N/A			10,556	-	-	149,941.25	657,317.97	-		807,259.22
129			6108	TERRA-GEN 251 WIND XIII	OS4		N/A			7,710	-	-	99,854.74	478,185.35	-		578,040.09
130			3011	TERRA-GEN DIXIE VALLEY	OS2		N/A			422,219	-	-	10,839,176.98	26,408,240.09	-		37,247,417.07
131			6098	THE BANK OF NY TRUST CO	OS4		N/A			3,252	-	-	75,732.89	200,516.61	-		276,249.50
132			4035	THREE VALLEYS MWD FULRTN	OS4		N/A			1,208	-	-	30,117.36	48,597.80	-		78,715.16
133			4036	THREE VALLEYS MWD MIRAMAR	OS4		N/A			1,554	-	-	33,389.59	64,893.97	-		98,283.56
134			4037	THREE VALLEYS MWD WILLMS	OS4		N/A			1,713	-	-	45,675.85	68,713.48	-		114,389.33
135			1132	TOYON LANDFILL GAS CONV	OS4		N/A			9,511	-	-	(833.06)	417,908.54	-		417,075.48
136			1126	VENTURA REGIONAL SANITATI	OS4		N/A			13	-	-	0.75	609.76	-		610.51
137			1221	VENTURA REGIONAL SNT DIST	OS4		N/A			2,683	-	-	-	254,202.39	-		254,202.39
138			6102	VICTORY GARDEN/PHASE IV	OS4		N/A			16,820	-	-	239,045.40	1,051,787.65	-		1,290,833.05
139			6103	VICTORY GARDEN/PHASE IV	OS4		N/A			13,185	-	-	213,716.71	833,687.16	-		1,047,403.87
140			6104	VICTORY GARDEN/PHASE IV	OS4		N/A			15,890	-	-	187,743.07	983,529.30	-		1,171,272.37
141			3006	VULCAN/BN GEOTHERMAL	OS2		N/A			299,659	-	-	5,621,582.94	18,741,301.35	-		24,362,884.29
142			1093	W.M. ENERGY SOLUTIONS,INC	OS7		N/A			14,328	-	-	21,762.86	557,510.30	-		579,273.16
143			1095	W.M.ENERGY SOLUTIONS,INC.	OS7		N/A			11,871	-	-	18,580.27	468,000.49	-		486,580.76
144			4016	WALNUT VALLEY WATER DIST	OS4		N/A			853	-	-	18,020.60	35,632.06	-		53,652.66
145			6096	WESTWIND TRUST	OS4		N/A			25,767	-	-	623,981.71	1,025,005.53	-		1,648,987.24
146			6118	WINDPOWER PARTNERS 1993	OS4		N/A			8,421	-	-	80,256.11	521,471.66	-		601,727.77
147			6035	WINDPOWER PTNRS 1993 L.P.	OS2		N/A			9,255	-	-	84,732.01	573,088.94	-		657,820.95
148			6030	WINDPOWER PTNRS 1993 LP	OS2		N/A			22,888	-	-	170,013.40	1,421,425.14	(78,495.52)	(50)	1,512,943.02
149			6061	WINDRIDGE INC	OS4		N/A			1,722	-	-	4,622.64	74,523.94	-		79,146.58
150			6012	WINDSONG WIND PARK	OS2		N/A			3,137	-	-	15,981.10	178,251.23	-		194,232.33
151			6019	ZEPHYR PARK, LTD	OS2		N/A			9,308	-	-	172,176.16	577,954.81	-		750,130.97
152																	
153				SUB-TOTAL PURCHASED POWER						12,650,344	-	-	257,255,103.09	778,543,567.61	(308,890.39)		1,035,489,780.31
154				RENEWABLE ENERGY CREDITS											2,939,330.46		2,939,330.46
155																	
156				TOTAL PURCHASED POWER						12,650,344	-	-	257,255,103.09	778,543,567.61	2,630,440.07		1,038,429,110.77

160 OS1 "EVERGREEN" MEANS MINIMUM OF ONE YEAR, WITH AUTOMATIC ANNUAL
161 RENEWAL THEREAFTER. THE AVAILABILITY AND RELIABILITY OF ENERGY
162 DELIVERED IS ON AN AS-AVAILABLE BASIS.

164 OS2 LONG-TERM POWER PURCHASE AGREEMENTS WITH RENEWABLE /
165 ALTERNATIVE RESOURCES. "LONG-TERM" MEANS FIVE YEARS OR GREATER.
166 THE AVAILABILITY AND RELIABILITY OF ENERGY DELIVERY MUST MATCH THE
167 DEDICATED FIRM MW AS SPECIFIED IN THE CONTRACT.

169 OS3 EVERGREEN POWER PURCHASE AGREEMENT WITH RENEWABLE / ALTERNATIVE
170 RESOURCES LESS THAN 100 KW. "EVERGREEN" MEANS MINIMUM OF ONE YEAR,
171 WITH AUTOMATIC ANNUAL RENEWAL THEREAFTER. THE AVAILABILITY AND
172 RELIABILITY OR ENERGY DELIVERED IS ON AN AS-AVAILABLE BASIS.

Total Renewable Cost (Capacity & Energy)	1,038,429,110.77
Total MWhs	12,650,344
$ / MWhs	82.09

Total Renewable Cost (Energy only)	781,174,007.68
Total MWhs	12,650,344
$ / MWhs	61.75

1/14/2011

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Page	Line #	QFID #	Name of Company or Public Authority (Footnote Affiliations) (a)	Stat Class (b)	Ferc Rate Sched No. (c)	Avg. Mo. Bill Demand (d)	Actual Demand (MWH) Avg. Mo. NCP Dmd (e)	Actual Demand (MWH) Avg. Mo. CP Dmd (f)	MWH Purchased (g)	Power Exchanges MWH Received (h)	Power Exchanges MWH Delivered (i)	Cost / Settlement of Power Demand ($) (j)	Cost / Settlement of Power Energy ($) (k)	Cost / Settlement of Power Other ($) (l)		Total ($) (m)
	OS4		LONG-TERM POWER PURCHASE AGREEMENTS WITH RENEWABLE / ALTERNATIVE RESOURCES. "LONG-TERM" MEANS FIVE YEARS OR GREATER. THE AVAILABILITY AND RELIABILITY OF ENERGY DELIVERED IS ON AN AS AVAILABLE BASIS.													
	OS7		LONG-TERM POWER PURCHASE AGREEMENTS WITH RENEWABLE / ALTERNATIVE RESOURCES. "LONG-TERM" MEANS FIVE YEARS OR GREATER. THE AVAILABILITY AND RELIABILITY OF ENERGY DELIVERY MUST MATCH THE DEDICATED FIRM MW AS SPECIFIED IN THE CONTRACT.													
	OS8		SCE CUSTOMERS ON THE FRINGE OF SCE'S SERVICE AREA.													
	OS9		TERMINATION AGREEMENT.													
	OS10		REPLACEMENT FOR LOST ENERGY DUE TO DIVERSION FROM MILL CREEK.													
	OS11		SETTLEMENT FOR GENERATION DEVIATION FROM TRANSMISSION SERVICE SCHEDULE.													
	OS12		LOWER COLORADO RIVER MULTI-SPECIES CONSERVATION PROGRAM.													
	OS13		BROKERS													

PG&E Data Response

PACIFIC GAS AND ELECTRIC COMPANY
Direct Access Reopening OIR
Rulemaking 07-05-025
Data Response

PG&E Data Request No.:	ED_001-01		
PG&E File Name:	DirectAccessReopeningOIR_DR_ED_001-Q01		
Request Date:	December 14, 2010	Requester DR No.:	ED_DR001
Date Sent:	December 16, 2010	Requesting Party:	Steve Roscow
PG&E Witness:	Donna Barry	Requester:	Energy Division on behalf of Joint Parties

QUESTION 1

Provide 2009 FERC Form #1 Data (IOU's) – Average cost of renewables in IOU portfolio.

ANSWER 1

The 2009 FERC Form 1 purchase power data is shown in Attachment 1. Attachment 2 summarizes the renewable data and calculates an average cost for 2009 renewable delivered energy.

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) *An Original (2) A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (ie., transactions 'involving a balanc ing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (ie., th e supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emerg ency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service fi rm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of t he contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reli ability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" me ans longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, c apacity, etc. and any settlements for imbalanced exchanges.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1						
2	PAGES 326 AND 327 WERE INTENTIONALLY					
3	LEFT BLANK. SEE NEXT PAGES FOR THE					
4	REQUIRED INFORMATION					
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18						
19						

Name of Respondent	This Report Is:	Date of Report	Year of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) *An Original (2) A Resubmission	(Mo, Da, Yr)	End of 2009/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (t). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (1) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
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Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) *An Original (2) A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	QUALIFYING FACILITIES (QF's)		(3)	(4)		
2						
3	THERMAL: ENHANCED OIL RECOVERY					
4						
5	AERA ENERGY LLC. (COALINGA)	LU		N/A	2.982	N/A
6	AERA ENERGY LLC. (N. MIDWAY SUNSET)	LU		N/A	0.000	N/A
7	AERA ENERGY LLC. (OXFORD)	LU		N/A	0.000	N/A
8	AERA ENERGY LLC. (S. BELRIDGE)	LU		N/A	8.271	N/A
9	BADGER CREEK LIMITED	LU		42.000	47.694	N/A
10	BEAR MOUNTAIN LIMITED	LU		42.000	48.861	N/A
11	BERRY PETROLEUM COGEN	LU		N/A	37.066	N/A
12	BERRY PETROLEUM COMPANY	LU		N/A	12.352	N/A
13	CHALK CLIFF LIMITED	LU		42.000	47.762	N/A
14	CHEVRON U.S.A. INC. (FEE C)	LU		N/A	4.088	N/A
15	CHEVRON U.S.A INC. (FEE A)	LU		N/A	1.824	N/A
16	CHEVRON U.S.A. INC. (SE KERN RIVER)	LU		N/A	12.867	N/A
17	CHEVRON U.S.A. INC. (MCKITTRICK)	LU		N/A	6.162	N/A
18	CHEVRON USA (COALINGA)	LU		N/A	9.785	N/A
19	CHEVRON USA (CYMRIC)	LU		N/A	8.593	N/A
20	CHEVRON USA (EASTRIDGE)	LU		N/A	9.586	N/A
21	CHEVRON USA, INC. (NORTH MIDWAY)	LU		N/A	0.427	N/A
22	CHEVRON USA (TAFT/CADET)	LU		N/A	3.514	N/A
23	COALINGA COGENERATION COMPANY	LU		33.000	40.545	N/A
24	DAI / OILDALE , INC.	LU		29.000	29.755	N/A
25	DOUBLE "C" LIMITED	LU		47.000	50.433	N/A
26	HIGH SIERRA LIMITED	LU		47.000	47.162	N/A
27	KERN FRONT LIMITED	LU		47.000	49.153	N/A
28	LIVE OAK LIMITED	LU		42.000	48.452	N/A
29	MCKITTRICK LIMITED	LU		42.000	47.957	N/A
30	MIDSET COGEN. CO.	LU		N/A	37.336	N/A
31	MIDWAY-SUNSET COGEN. CO.	LU		N/A	29.075	N/A
32	PLAINS EXPLORATION AND PRODUCTION COMPANY (DOM	LU		N/A	2.173	N/A
33	PLAINS EXPLORATION AND PRODUCTION COMPANY (WELI	LU		N/A	1.331	N/A
34	SALINAS RIVER COGEN CO	LU		N/A	38.208	N/A
35	SARGENT CANYON COGERATION COMPANY	LU		N/A	36.991	N/A
36	TEXACO EXPLORATION & PRODUCTION, INC. (FEE A)	LU		N/A		N/A
37	TEXACO EXPLORATION & PRODUCTION, INC. (FEE C)	LU		N/A		N/A
38	TEXACO EXPLORATION & PRODUCTION, INC. (SE KERN RI\	LU		N/A		N/A
39	TEXACO INC. (MCKITTRICK)	LU		N/A	0.000	N/A
40						
41	Subtotal			413.000	720.406	
42						
43	THERMAL: COGENERATION					
44						
45	ALTAMONT COGENERATION CORP.	LU		5.700	0.000	N/A
46	BLUEGRASS CONTAINER COMPANY, LLC	LU		N/A	0.000	N/A
47	CALPINE KING CITY COGEN.	LU		111.000	120.435	N/A
48						
49						

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Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) *An Original (2) A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report End of 2009/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

Megawatthours Purchased (g)	POWER EXCHANGES Megawatthours Received (h)	Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
							1
							2
							3
							4
16,746			163,354	760,586		923,940	5
-						-	6
-						-	7
13,062			97,943	566,261		664,204	8
352,399			9,733,184	15,515,119		25,248,303	9
371,450			10,125,967	16,620,124		26,746,091	10
291,146			3,049,651	12,906,314		15,955,965	11
91,021			934,582	4,051,655		4,986,237	12
367,425			9,138,194	16,574,043		25,712,237	13
11,015			114,385	437,114		551,499	14
26,549			253,888	1,107,558		1,361,446	15
72,295			805,030	3,593,456		4,398,486	16
37,239			404,840	1,645,744		2,050,584	17
63,487			654,271	2,898,000		3,552,271	18
49,116			479,357	2,182,496		2,661,853	19
37,890			249,055	1,781,270		2,030,325	20
71			427	2,947		3,374	21
14,672			147,955	553,791		701,746	22
301,965			3,110,441	13,684,559		16,795,000	23
221,305			6,012,898	9,754,842		15,767,740	24
242,874			6,157,068	11,959,336		18,116,404	25
208,908			5,529,873	10,142,372		15,672,245	26
238,357			6,438,345	11,529,306		17,967,651	27
383,009			9,853,451	17,325,813		27,179,264	28
387,055			9,825,482	17,406,733		27,232,215	29
300,067			3,159,955	13,473,015		16,632,970	30
58,182			1,059,356	3,019,257		4,078,613	31
11,104			118,367	479,889		598,256	32
4,825			34,665	221,178		255,843	33
277,909			2,898,444	12,620,918		15,519,362	34
273,499			2,939,779	12,370,475		15,310,254	35
						-	36
						-	37
						-	38
(55)			242	(4,151)		(3,909)	39
							40
4,724,587	-	-	93,490,449	215,180,020	-	308,670,469	41
							42
							43
							44
-						-	45
(138)			68	(10,667)		(10,599)	46
624,902			23,954,307	26,123,114		50,077,421	47
							48
							49

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Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) *An Original (2) A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1						
2	THERMAL: COGENERATION (cont.)					
3	CALPINE GILROY COGEN, L.P.	LU		N/A	0.000	N/A
4	CALPINE MONTEREY COGEN INC.	LU		20.900	29.585	N/A
5	CALPINE PITTSBURG POWER PLANT	LU		N/A	9.048	N/A
6	CARDINAL COGEN	LU		N/A	31.433	N/A
7	UCSF	LU		N/A	2.056	N/A
8	CHEVRON RICHMOND REFINERY	LU		N/A	15.636	N/A
9	CHEVRON USA (CONCORD)	LU		N/A	1.707	N/A
10	CONOCOPHILLIPS COMPANY	LU		N/A	7.070	N/A
11	CROCKETT COGEN	LU		240.000	228.639	N/A
12	FRESNO COGENERATION CORPORATION	LU		33.000	30.250	N/A
13	FRITO LAY COGEN	LU		N/A	0.772	N/A
14	GATX/CALPINE COGEN-AGNEWS INC.	LU		24.000	26.683	N/A
15	GRAPHIC PACKING INT'L (BLUE GRASS)	LU		N/A	18.100	N/A
16	GREENLEAF UNIT #1	LU		49.200	49.780	N/A
17	GREENLEAF UNIT #2	LU		49.200	49.659	N/A
18	MARTINEZ COGEN LIMITED PARTNERSHIP	LU		10.000	36.228	N/A
19	MONTEREY POWER COMPANY	LU		5.500	0.000	N/A
20	NAPA STATE HOSPITAL	LU		N/A	0.489	N/A
21	OCCIDENTAL OF ELK HILLS	LU		N/A	0.000	N/A
22	OILDALE ENERGY LLC	LU		29.000	40.125	N/A
23	OROVILLE COGEN	LU		7.500	5.016	N/A
24	PE - BERKELEY, INC.	LU		22.470	26.586	N/A
25	PE - KES KINGSBURG,LLC	LU		34.500	32.872	N/A
26	RHODIA INC. (RHONE- POULENC)	LU		N/A	0.659	N/A
27	RIPON COGENERATION, LLC	LU		42.000	48.931	N/A
28	SANGER POWER, L.L.C.	LU		38.000	41.654	N/A
29	SAINT AGNES MED. CTR	LU		N/A	1.049	N/A
30	SAN JOAQUIN POWER COMPANY	LU		8.526	0.000	N/A
31	SAN JOSE COGEN	LU		N/A	0.158	N/A
32	SRI INTERNATIONAL	LU		N/A	2.078	N/A
33	SUNNYSIDE	LU		N/A	0.000	N/A
34	UNITED AIRLINES (COGEN)	LU		25.650	26.963	N/A
35	WHEELABRATOR LASSEN INC.	LU		42.000	19.505	N/A
36	YUBA CITY COGEN	LU		46.000	49.002	N/A
37						
38	Subtotal			844.146	952.166	
39						
40	THERMAL: WASTE TO ENERGY					
41						
42	GWF POWER SYSTEMS INC. #1	LU		16.000	19.479	N/A
43	GWF POWER SYSTEMS INC. #2	LU		16.000	19.298	N/A
44	GWF POWER SYSTEMS INC. #3	LU		16.000	18.983	N/A
45	GWF POWER SYSTEMS INC. #4	LU		16.000	19.284	N/A
46	GWF POWER SYSTEMS INC. #5	LU		16.000	19.464	N/A
47	HANFORD L.P.	LU		22.000	24.990	N/A
48	MONTEREY REGIONAL WASTE MGMT DIST.	LU		1.150	1.920	N/A
49	MONTEREY REGIONAL WATER	LU		N/A	0.168	N/A

Name of Respondent	This Report Is:	Date of Report	Year of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) *An Original (2) A Resubmission	(Mo, Da, Yr)	End of 2009/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

Megawatthours Purchased (g)	POWER EXCHANGES Megawatthours Received (h)	Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
							1
							2
-			20,681,317	(590,427)		20,090,890	3
160,903			5,738,843	6,914,903		12,653,746	4
32,636			173,727	1,299,414		1,473,141	5
178,022			2,157,476	7,731,242		9,888,718	
5,247			9,688	235,972		245,660	7
24,838			-	867,500		867,500	8
6,144			75,979	270,713		346,692	9
30,719			179,047	1,430,149		1,609,196	10
698,692			54,176,795	25,694,689		79,871,484	11
49,890			7,299,819	2,191,632		9,491,451	12
786			7,909	35,281		43,190	13
151,701			5,410,442	6,450,461		11,860,903	14
147,456			1,493,575	6,612,028		8,105,603	15
224,499			9,881,336	9,246,352		19,127,688	16
235,835			10,070,952	9,763,199		19,834,151	17
145,967			4,710,446	6,029,118		10,739,564	18
						-	19
						-	20
						-	21
306,539			6,421,146	13,475,953		19,897,099	22
11,309			1,400,865	461,045		1,861,910	23
188,266			4,746,403	8,407,977		13,154,380	24
111,183			8,358,982	5,026,302		13,385,284	25
1,160			3,441	50,295		53,736	26
257,467			8,248,317	12,722,890		20,971,207	27
126,461			8,361,285	6,032,891		14,394,176	28
						-	29
						-	30
6			4	286		290	31
7,369			64,333	317,244		381,577	32
-				500,000		500,000	33
179,000			4,673,700	7,973,946		12,647,646	34
55,058			6,307,000	2,003,766		8,310,766	35
136,698			10,629,158	6,291,043		16,920,201	36
							37
4,098,615	-	-	205,236,360	173,558,311	-	378,794,671	38
							39
							40
							41
155,258			3,723,498	10,142,538		13,866,036	42
159,698			3,890,606	10,351,797		14,242,403	43
157,998			3,791,494	10,247,233		14,038,727	44
158,889			3,616,850	10,259,427		13,876,277	45
156,230			3,925,865	10,090,881		14,016,746	46
200,154			4,553,143	13,052,353		17,605,496	47
23,338			143,903	2,094,071		2,237,974	48
256			2,055	12,367		14,422	49

SB_GT&S_0015066

Name of Respondent	This Report Is:	Date of Report	Year of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) *An Original (2) A Resubmission	(Mo, Da, Yr)	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1						
2	THERMAL: WASTE TO ENERGY (cont…)					
3						
4	COVANTA POWER PACIFIC (SALINAS)	LU		N/A	0.995	N/A
5	COVANTA POWER PACIFIC (STOCKTON)	LU		N/A	0.757	N/A
6	EBMUD (OAKLAND)	LU		N/A	1.129	N/A
7						
8	GAS RECOVERY SYS. (AMERICAN CYN)	LU		1.467	1.350	N/A
9	GAS RECOVERY SYS. (GUADALUPE)	LU		1.443	2.376	N/A
10	GAS RECOVERY SYS. (MENLO PARK)	LU		1.877	1.336	N/A
11	GAS RECOVERY SYS. (NEWBY ISLAND 1)	LU		1.730	1.941	N/A
12	GAS RECOVERY SYS. (NEWBY ISLAND 2)	LU		3.760	4.194	N/A
13	PALO ALTO LANDFILL	LU		N/A	0.000	N/A
14	STANISLAUS WASTE ENERGY CO.	LU		16.500	19.082	N/A
15	WASTE MANAGEMENT RENEWABLE ENERGY	LU		N/A	15.729	N/A
16						
17						
18	Subtotal			129.927	172.472	
19						
20						
21						
22	THERMAL BIOMASS					
23						
24	BIG VALLEY POWER LLC	LU		N/A	1.105	N/A
25	BURNEY FOREST PRODUCTS	LU		24.000	31.677	N/A
26	COLLINS PINE	LU		5.500	8.811	N/A
27	DG FAIRHAVEN POWER, LLC	LU		16.000	16.214	N/A
28	HL POWER	LU		20.000	27.372	N/A
29	COVANTA MENDOTA L. P.	LU		22.000	25.495	N/A
30	OGDEN POWER PACIFIC, INC. (BURNEY)	LU		9.750	10.587	N/A
31	OGDEN POWER PACIFIC, INC. (CHINESE STATION)	LU		19.800	19.565	N/A
32	OGDEN POWER PACIFIC, INC.(MT. LASSEN)	LU		10.500	10.446	N/A
33	OGDEN POWER PACIFIC, INC. (OROVILLE)	LU		16.500	17.936	N/A
34	RIO BRAVO FRESNO	LU		23.500	24.683	N/A
35	RIO BRAVO ROCKLIN	LU		22.000	24.899	N/A
36	SIERRA PACIFIC IND. (ANDERSON)	LU		N/A	2.883	N/A
37	SIERRA PACIFIC IND. (BURNEY)	LU		9.500	14.289	N/A
38	SIERRA PACIFIC IND. (LINCOLN)	LU		4.980	13.958	N/A
39	SIERRA PACIFIC IND. (QUINCY)	LU		12.500	20.082	N/A
40	SIERRA PACIFIC IND.(SONORA)	LU		9.842	0.000	N/A
41	THERMAL ENERGY DEV. CORP.	LU		13.000	19.502	N/A
42	TOWN OF SCOTIA COMPANY, LLC (PACIFIC LUMBER)	LU		N/A	20.680	N/A
43	WADHAM ENERGY LTD. PART.	LU		N/A	0.000	N/A
44	WHEELABRATOR SHASTA	LU		49.680	50.301	N/A
45	WOODLAND BIOMASS	LU		22.000	26.118	N/A
46						
47	Subtotal			311.052	386.602	
48						
49						

Name of Respondent	This Report Is:	Date of Report	Year of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) *An Original (2) A Resubmission	(Mo, Da, Yr)	End of 2009/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
							1
							2
							3
5,693			69,187	256,043		325,230	4
5,649			53,703	245,895		299,598	5
2,739			42,310	93,386		135,696	7
						-	8
6,983			162,353	463,799		626,152	9
17,938			293,251	1,185,763		1,479,014	10
9,277			(76,039)	613,376		537,337	
						-	11
32,973			560,899	2,194,639		2,755,538	12
						-	13
141,945			2,964,647	9,282,788		12,247,435	14
42,280			214,099	2,792,880		3,006,979	15
							16
							17
1,277,298	-	-	27,931,824	83,379,236	-	111,311,060	18
							19
							20
							21
							22
							23
1,581			123,313	114,528		237,841	24
228,153			5,751,043	14,719,047		20,470,090	25
46,348			812,545	2,957,603		3,770,148	26
108,712			2,572,682	6,150,147		8,722,829	27
162,502			3,747,562	7,338,946		11,086,508	28
190,138			4,909,074	12,676,634		17,585,708	29
57,059			1,468,060	2,638,835		4,106,895	30
126,884			3,009,142	8,395,724		11,404,866	31
55,720			1,556,377	2,574,315		4,130,692	32
129,702			2,498,236	8,506,525		11,004,761	33
185,959			4,805,120	12,248,972		17,054,092	34
183,080			4,914,741	12,043,882		16,958,623	35
8,987			38,746	385,998		424,744	36
88,352			1,839,750	5,696,492		7,536,242	37
87,255			1,580,890	5,682,752		7,263,642	38
118,464			2,438,955	7,664,535		10,103,490	39
17,913			376,194	1,132,900		1,509,094	40
141,495			3,071,148	9,299,306		12,370,454	41
73,045			-	7,758,354		7,758,354	42
-			101,029	-		101,029	43
395,731			8,993,428	25,869,196		34,862,624	44
162,696			4,622,680	7,471,153		12,093,833	45
							46
2,569,776	-	-	59,230,715	161,325,844	-	220,556,559	47
							48
							49

Name of Respondent	This Report Is:	Date of Report	Year of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) *An Original (2) A Resubmission	(Mo, Da, Yr)	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1						
2	THERMAL: COAL					
3						
4	MT.POSO COGENERATION CO.	LU		N/A	54.163	N/A
5	POSDEF (COGEN NATIONAL)	LU		44.000	16.554	N/A
6	RIO BRAVO POSO	LU		30.000	36.027	N/A
7	STOCKTON COGEN CO.	LU		N/A	51.084	N/A
8						
9	Subtotal			74.000	157.827	
10						
11	THERMAL: ESTIMATED					
12						
13	ACTUAL TO ESTIMATE ADJUSTMENT			N/A	N/A	N/A
14						
15						
16	TOTAL - THERMAL RESOURCES			1772.125	2389.474	
17						
18						
19	RENEWABLE: GEOTHERMAL					
20						
21	AMEDEE GEOTHERMAL VENTURE 1	LU		0.369	0.705	N/A
22						
23						
24	Subtotal			0.369	0.705	
25						
26						
27						
28						
29						
30						
31	RENEWABLE: WIND					
32						
33	ALTAMONT ENERGY CORP	LU		N/A	0.000	N/A
34	ALTAMONT MIDWAY LTD.	LU		N/A	5.623	N/A
35	ALTAMONT POWER LLC (PARTNERS 1)	LU		N/A	0.000	N/A
36	ALTAMONT POWER LLC (PARTNERS 2)	LU		N/A	0.000	N/A
37	ALTAMONT POWER LLC (3-4)	LU		N/A	1.779	N/A
38	ALTAMONT POWER LLC (4-4)	LU		N/A	7.552	N/A
39	ALTAMONT POWER LLC (6-4)	LU		N/A	6.744	N/A
40	GREEN RIDGE POWER LLC (10 MW)	LU		N/A	9.791	N/A
41	GREEN RIDGE POWER LLC (100 MW - A)	LU		N/A	25.486	N/A
42	GREEN RIDGE POWER LLC (100 MW - B)	LU		N/A	0.059	N/A
43	GREEN RIDGE POWER LLC (100 MW - C)	LU		N/A	3.339	N/A
44	GREEN RIDGE POWER LLC (100 MW - D)	LU		N/A	5.399	N/A
45	GREEN RIDGE POWER LLC (110 MW)	LU		N/A	88.354	N/A
46	GREEN RIDGE POWER LLC (23.8 MW)	LU		N/A	5.470	N/A
47	GREEN RIDGE POWER LLC (30 MW)	LU		N/A	0.000	N/A
48						
49						

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) *An Original (2) A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report End of 2009/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

Megawatthours Purchased (g)	POWER EXCHANGES: Megawatthours Received (h)	POWER EXCHANGES: Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
							1
							2
							3
372,236			1,955,231	32,179,396		34,134,627	4
62,508			525,788	3,798,735		4,324,523	5
280,113			7,712,766	18,475,868		26,188,634	6
369,211			1,990,100	24,534,844		26,524,944	7
							8
1,084,068	-	-	12,183,885	78,988,843	-	91,172,728	9
							10
							11
							12
						-	13
							14
							15
13,754,344			398,073,233	712,432,254		1,110,505,487	16
							17
							18
							19
							20
3,975			33,349	163,022		196,371	21
							22
							23
3,975	-	-	33,349	163,022	-	196,371	24
							25
							26
							27
							28
							29
							30
							31
							32
						-	33
14,100			247,008	518,631		765,639	34
							35
						-	36
7,596			127,451	459,783		587,234	37
32,844			556,022	1,976,034		2,532,056	38
29,339			529,491	1,772,406		2,301,897	39
20,212			424,995	1,195,057		1,620,052	40
87,675			1,807,463	5,316,795		7,124,258	41
						-	42
11,533			258,353	697,195		955,548	43
18,192			376,311	1,102,176		1,478,487	44
288,283			5,366,672	16,558,339		21,925,011	45
19,172			319,403	1,136,303		1,455,706	46
							47
							48
							49

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) *An Original (2) A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1						
2	RENEWABLE: WIND (cont)					
3						
4	GREEN RIDGE POWER LLC (5.9 MW)	LU		N/A	3.524	N/A
5	GREEN RIDGE POWER LLC (70 MW - A)	LU		N/A	0.000	N/A
6	GREEN RIDGE POWER LLC (70 MW - B)	LU		N/A	7.784	N/A
7	GREEN RIDGE POWER LLC (70 MW - C)	LU		N/A	11.729	N/A
8	GREEN RIDGE POWER LLC (70 MW - D)	LU		N/A	0.632	N/A
9	GREEN RIDGE POWER LLC (70 MW)	LU		N/A	29.034	N/A
10	INTERNATIONAL TURBINE RESEARCH	LU		N/A	14.408	N/A
11	J.V.ENTERPRISE	LU		N/A	0.000	N/A
12	NORTHWIND ENERGY	LU		N/A	8.395	N/A
13	PATTERSON PASS WIND FARM LLC	LU		N/A	31.651	N/A
14	SEA WEST ENERGY GROUP (TOTALS)	LU		N/A	4.727	N/A
15	TRES VAQUEROS WIND FARMS, LLC			N/A	6.010	N/A
16						
17	Subtotal			0.000	277.490	
18						
19	RENEWABLE: HYDRO					
20						
21	BAKER STATION ASSOCIATES L.P.	LU		N/A	0.978	N/A
22	CALAVERAS CTY WD	LU		N/A	0.902	N/A
23	EL DORADO (MONTGOMERY CK)	LU		N/A	1.443	N/A
24	FRIANT POWER AUTHORITY	LU		N/A	16.226	N/A
25	HAYPRESS HYDROELECTRIC, INC. (LWR)	LU		N/A	1.866	N/A
26	HAYPRESS HYDROELECTRIC, INC. (MDL)	LU		N/A	1.923	N/A
27	HUMBOLDT BAY MWD	LU		N/A	0.759	N/A
28	HYPOWER, INC.	LU		N/A	8.972	N/A
29	INDIAN VALLEY HYDRO	LU		N/A	0.316	N/A
30	KERN HYDRO (OLCESE)	LU		N/A	5.427	N/A
31	MADERA-CHOWCHILLA WATER AND POWER AUTHORITY	LU		N/A	1.023	N/A
32	MALACHA HYDRO L.P.	LU		N/A	20.102	N/A
33	MEGA RENEWABLES (BIDWELL DITCH)	LU		N/A	1.576	N/A
34	MEGA RENEWABLES (HATCHET CRK)	LU		N/A	2.949	N/A
35	MEGA RENEWABLES (ROARING CRK)	LU		N/A	0.872	N/A
36	MERCED ID (PARKER)	LU		N/A	1.014	N/A
37	MONTEREY CTY WATER RES AGENCY	LU		N/A	1.578	N/A
38	NELSON CREEK POWER INC.	LU		N/A	0.538	N/A
39	NEVADA IRRIGATION DISTRICT/BOWMAN HYROELECTRIC I	LU		N/A	2.035	N/A
40	NID/COMBIE SOUTH	LU		N/A	0.879	N/A
41	NID/SCOTTS FLAT	LU		N/A	0.552	N/A
42	NORMAN ROSS BURGESS	LU		N/A	1.376	N/A
43	OLSEN POWER PARTNERS	LU		N/A	1.522	N/A
44	ORANGE COVE IRRIGATION DIST.	LU		N/A	0.438	N/A
45	ROCK CREEK L.P.	LU		N/A	0.887	N/A
46	SNOW MOUNTAIN HYDRO LLC (BURNEY CREEK)	LU		N/A	0.979	N/A
47	SNOW MOUNTAIN HYDRO LLC (COVE)	LU		N/A	2.348	N/A
48	SNOW MOUNTAIN HYDRO LLC (LOST CREEK 1)	LU		N/A	0.672	N/A
49	SNOW MOUNTAIN HYDRO LLC (LOST CREEK 2)	LU		N/A	0.349	N/A

Name of Respondent	This Report Is:	Date of Report	Year of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) *An Original (2) A Resubmission	(Mo, Da, Yr)	End of 2009/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

Megawatthours Purchased (g)	POWER EXCHANGES: Megawatthours Received (h)	POWER EXCHANGES: Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
							1
							2
							3
12,065			257,187	730,744		987,931	4
						-	5
20,583			541,619	1,206,948		1,748,567	6
31,911			827,291	1,868,615		2,695,906	7
1,669			43,819	97,875		141,694	8
92,670			1,945,901	5,594,019		7,539,920	9
26,198			567,051	1,634,188		2,201,239	10
						-	11
15,480			270,857	952,591		1,223,448	12
40,654			740,053	2,485,488		3,225,541	13
11,712			192,901	426,749		619,650	14
11,650			179,398	633,847		813,245	15
							16
793,538	-	-	15,579,246	46,363,783	-	61,943,029	17
							18
							19
							20
2,622			32,344	136,544		168,888	21
5,052			79,103	188,111		267,214	22
6,284			80,297	444,133		524,430	23
100,525			2,579,427	6,020,138		8,599,565	24
7,444			171,523	460,736		632,259	25
7,393			153,187	472,058		625,245	26
3,926			21,567	247,995		269,562	27
31,004			349,386	1,347,724		1,697,110	28
1,330			10,953	76,931		87,884	29
32,203			266,552	1,951,884		2,218,436	30
5,331			138,654	315,455		454,109	31
31,704			1,557,180	2,265,056		3,822,236	32
11,171			205,234	501,380		706,614	33
12,280			166,167	588,239		754,406	34
3,646			45,939	179,109		225,048	35
5,977			82,579	207,160		289,739	36
10,868			143,932	472,476		616,408	37
2,156			29,736	149,405		179,141	38
12,672			290,722	769,208		1,059,930	39
4,907			20,123	335,235		355,358	40
3,272			27,227	193,138		220,365	41
5,655			89,269	278,840		368,109	42
4,361			61,653	190,956		252,609	43
						-	44
1,321			17,080	92,717		109,797	45
3,894			51,845	270,664		322,509	46
9,641			122,919	665,330		788,249	47
5,031			22,953	308,180		331,133	48
2,473			11,947	163,941		175,888	49

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) *An Original (2) A Resubmission		End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1						
2	RENEWABLE: HYDRO (cont)					
3						
4	SNOW MOUNTAIN HYDRO LLC (PONDEROSA BAILEY CREE	LU		N/A	0.438	N/A
5	SONOMA COUNTY WATER AGENCY	LU		1.246	1.421	N/A
6	SOUTH SAN JOAQUIN ID (FRANKENHEIMER)	LU		N/A	3.044	N/A
7	SOUTH SAN JOAQUIN ID (WOODWARD)	LU		N/A	1.001	N/A
8	STS HYDROPOWER LTD. (KANAKA)	LU		N/A	0.539	N/A
9	STS HYDROPOWER LTD. (KEKAWAKA)	LU		N/A	2.261	N/A
10	TKO POWER (SOUTH BEAR CREEK)	LU		N/A	0.926	N/A
11	TRI-DAM AUTHORITY	LU		15.000	13.227	N/A
12	YOLO COUNTY FLOOD & WCD	LU		N/A	0.000	N/A
13	YUBA COUNTY WATER (DEADWOOD CREEK)			N/A	0.594	N/A
14						
15	Subtotal			16.246	103.951	
16						
17	RENEWABLE: ESTIMATED					
18						
19	ACTUAL TO ESTIMATE ADJUSTMENT			N/A	N/A	N/A
20						
21						
22	TOTAL - RENEWABLE RESOURCES			16.615	382.146	
23						
24	SMALL POWER PRODUCERS - RENEWABLE (6)	LU		1.775	11.823	N/A
25	SMALL POWER PRODUCERS - THERMAL (6)	LU		0	0.133	N/A
26						
27	**TOTAL QUALIFYING FACILITIES**			**1790.515**	**2783.576**	
28						
29	IRRIGATION DISTRICTS AND WATER AGENCIES					
30						
31	EAST BAY MUNICIPAL UTILITY DISTRICT (EMBUD) (1)	LU	NON-FERC	N/A	N/A	N/A
32	MERCED IRRIGATION DISTRICT	LU	NON-FERC	N/A	N/A	N/A
33	NEVADA IRRIGATION DISTRICT	LU	NON-FERC	N/A	N/A	N/A
34	OROVILLE-WYANDOTTE IRRIGATION DISTRICT	LU	NON-FERC	N/A	N/A	N/A
35	PLACER COUNTY WATER AGENCY	LU	NON-FERC	N/A	N/A	N/A
36	SIERRA PACIFIC POWER COMPANY	OS	A	N/A	N/A	N/A
37	SOLANO IRRIGATION DISTRICT	LU	NON-FERC	N/A	N/A	N/A
38	TRI-DAM IRRIGATION DISTRICT	LU	NON-FERC	N/A	N/A	N/A
39	YUBA COUNTY WATER AGENCY	LU	NON-FERC	N/A	N/A	N/A
40						
41	Subtotal					
42						
43						
44						
45						
46						
47						
48						
49						

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) *An Original (2) A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report End of 2009/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
							1
							2
							3
1,212			28,902	63,554		92,456	4
8,143			145,261	342,555		487,816	5
15,265			208,617	574,407		783,024	6
5,470			79,255	200,648		279,903	7
771			9,125	54,408		63,533	8
5,157			17,416	373,131		390,547	9
1,826			13,835	132,777		146,612	10
86,859			2,628,313	3,446,308		6,074,621	11
						-	12
1,792			25,467	124,386		149,853	13
							14
460,638	-	-	9,985,689	24,604,917		34,590,606	15
							16
							17
							18
-			-	-		-	19
							20
							21
1,258,151			25,598,284	71,131,722		96,730,006	22
							23
49,898			734,980	2,706,622		3,441,602	24
2,895			9,890	135,184		145,074	25
							26
15,065,288	**-**	**-**	**424,416,387**	**786,405,782**	**-**	**1,210,822,169**	27
							28
							29
							30
					(87,416)	(87,416)	31
220,809				8,230,297		8,230,297	32
208,968				4,549,091		4,549,091	33
429,232				12,089,914		12,089,914	34
930,221				12,223,646		12,223,646	35
5,465				412,400		412,400	36
39,212				3,959,813		3,959,813	37
						-	38
972,277				16,763,145		16,763,145	39
							40
2,806,184	-	-	-	58,228,306	(87,416)	58,140,890	41
							42
							43
							44
							45
							46
							47
							48
							49

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) *An Original (2) A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1						
2	BILATERAL CONTRACTS:					
3	- RENEWABLE CONTRACTS					
4						
5	ARLINGTON WIND POWER PROJECT	LU	NON-FERC	N/A	N/A	N/A
6	BONNEVILLE POWER ADMINSTRATION (KLONDIKE IIIA)	LU	NON-FERC	N/A	N/A	N/A
7	BOTTLE ROCK	LU	NON-FERC	N/A	N/A	N/A
8	BUCKEYE HYDROELECTRIC PROJECT	LU	NON-FERC	N/A	N/A	N/A
9	BUENA VISTA ENERGY, LLC	LU	NON-FERC	N/A	N/A	N/A
10	CALPINE GEYSERS	LU	NON-FERC	N/A	N/A	N/A
11	CASTELANELLI BROS. BIOGAS	LU	NON-FERC	N/A	N/A	N/A
12	COMMUNITY RENEWABLE ENERGY SERVICES, INC	LU	NON-FERC	N/A	N/A	N/A
13	ETIWANDA POWER PLANT	LU	NON-FERC	N/A	N/A	N/A
14	FPLE DIABLO WINDS	LU	NON-FERC	N/A	N/A	N/A
15	GLOBAL AMPERSAND	LU	NON-FERC	N/A	N/A	N/A
16	IBERDROLA KLONDIKE (AKA PPM KLONDIKE)	LU	NON-FERC	N/A	N/A	N/A
17	IBERDROLA RENEWABLES (AKA PPM ENERGY)	LU	NON-FERC	N/A	N/A	N/A
18	MADERA RENEWABLE	LU	NON-FERC	N/A	N/A	N/A
19	NEVADA IRRIGATION DISTRICT NORTH COMBIE	LU	NON-FERC	N/A	N/A	N/A
20	PACIFICORP	LU	NON-FERC	N/A	N/A	N/A
21	SEMPRA EL DORADO SOLAR IMPORT	LU	NON-FERC	N/A	N/A	N/A
22	SHELL ENERGY	LU	NON-FERC	N/A	N/A	N/A
23	SHILOH	LU	NON-FERC	N/A	N/A	N/A
24	SHILOH I WIND PROJECT LLC	LU	NON-FERC	N/A	N/A	N/A
25	SIERRA POWER CORPORATION	LU	NON-FERC	N/A	N/A	N/A
26	WADHAM ENERGY LTD	LU	NON-FERC	N/A	N/A	N/A
27						
28	Subtotal					
29						
30	BILATERAL CONTRACTS:					
31	-WSPP/EEI					
32						
33	ARIZONA PUBLIC SERVICE	OS	6	N/A	N/A	N/A
34	BARCLAYS BANK PLC	OS	6	N/A	N/A	N/A
35	BONNEVILLE POWER ADMINISTRATION	OS	6	N/A	N/A	N/A
36	BP ENERGY COMPANY	OS	6	N/A	N/A	N/A
37	CALIFORNIA DEPT OF WATER RESOURCES	OS	6	N/A	N/A	N/A
38	CALPINE ENERGY SERVICES, L.P.	OS	6	N/A	N/A	N/A
39	CITIGROUP ENERGY INC	OS	6	N/A	N/A	N/A
40	CITY OF ROSEVILLE	OS	6	N/A	N/A	N/A
41	CITY OF SANTA CLARA (SVP MUNI)	OS	6	N/A	N/A	N/A
42	CONOCOPHILLIPS COMPANY	OS	6	N/A	N/A	N/A
43	CONSTELLATION ENERGY	OS	6	N/A	N/A	N/A
44	CORAL POWER, LLC	OS	6	N/A	N/A	N/A
45	CREDIT SUISSE ENERGY LLC	OS	6	N/A	N/A	N/A
46	DYNERGY FINANCIAL SERVICES	OS	6	N/A	N/A	N/A
47	FORTIS ENERGY MARKETING & TRADING GP	OS	6	N/A	N/A	N/A
48	IBERDROLA RENEWABLES (PPM ENERGY, INC.)	OS	6	N/A	N/A	N/A
49	J. ARON & COMPANY	OS	6	N/A	N/A	N/A

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

Megawatthours Purchased (g)	POWER EXCHANGES Megawatthours Received (h)	Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
							1
							2
							3
							4
229,929				23,119,616		23,119,616	5
-				547,238		547,238	6
88,310				6,141,951		6,141,951	7
3,234				324,796		324,796	8
101,080				5,637,896		5,637,896	9
3,316,890				178,677,571		178,677,571	10
710				74,467		74,467	11
61,776			1,410,150	2,708,189		4,118,339	12
28,664				1,381,161		1,381,161	13
64,149				2,786,649		2,786,649	14
97,361				7,492,563		7,492,563	15
451,154				30,726,961		30,726,961	16
-				4,206,773		4,206,773	17
134,604			2,080,939	6,098,839		8,179,778	18
223				21,871		21,871	19
220,825				15,448,246		15,448,246	20
21,668				3,516,074		3,516,074	21
131,640				9,239,279		9,239,279	22
377,342				32,400,629		32,400,629	23
197,396				10,928,986		10,928,986	24
43,677			996,386	1,978,479		2,974,865	25
173,588				14,481,533		14,481,533	26
							27
5,744,220	-	-	4,487,475	357,939,767	-	362,427,242	28
							29
							30
							31
							32
(3,200)				(64,000)		(64,000)	33
340,164				12,433,823		12,433,823	34
38,737				1,097,745		1,097,745	35
2,800				124,000		124,000	36
21,808				881,203		881,203	37
102,823				4,036,570		4,036,570	38
1,040,840				40,100,124		40,100,124	39
1,554				52,552		52,552	40
(810)				(26,758)		(26,758)	41
107,897				4,143,546		4,143,546	42
12,460				482,180		482,180	43
283,833				9,097,494		9,097,494	44
400				20,400		20,400	45
939,676				37,754,152		37,754,152	46
193,975				6,843,386		6,843,386	47
489,654				18,492,437		18,492,437	48
30				1,320		1,320	49

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) *An Original (2) A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1						
2	-WSPP/EEI (Continued)					
3						
4	JP MORGAN VENTURES ENERGY CORP (JPMVEC)	OS	6	N/A	N/A	N/A
5	LOS ANGELES DEPT OF WATER AND POWER	OS	6	N/A	N/A	N/A
6	MIRANT ENERGY TRADING LLC (MET)	OS	6	N/A	N/A	N/A
7	MODESTO IRRIGATION DISTRICT	OS	6	N/A	N/A	N/A
8	MORGAN STANLEY CAPITAL GROUP	OS	6	N/A	N/A	N/A
9	NCPA	OS	6	N/A	N/A	N/A
10	NEXTERA ENERGY POWER MARKETING, LLC (AKA FPL)	OS	6	N/A	N/A	N/A
11	NORTH AMERICAN CREDIT AND CLEARING CORP	OS	6	N/A	N/A	N/A
12	NRG POWER MARKETING INC.	OS	6	N/A	N/A	N/A
13	OCCIDENTAL POWER SERVICES, INC	OS	6	N/A	N/A	N/A
14	PACIFIC SUMMIT ENERGY LLC	OS	6	N/A	N/A	N/A
15	PACIFICORP	OS	6	N/A	N/A	N/A
16	PINNACLE WEST CAPITAL CORP	OS	6	N/A	N/A	N/A
17	PORTLAND GENERAL	OS	6	N/A	N/A	N/A
18	POWEREX CORP	OS	6	N/A	N/A	N/A
19	PUBLIC SERVICE COMPANY OF NEW MEXICO	OS	6	N/A	N/A	N/A
20	PUGET SOUND ENERGY	OS	6	N/A	N/A	N/A
21	RELIANT ENERGY SERVICES	OS	6	N/A	N/A	N/A
22	SACRAMENTO MUNICPAL UTILITY DISTRICT	OS	6	N/A	N/A	N/A
23	SALT RIVER PROJECT	OS	6	N/A	N/A	N/A
24	SAN DIEGO GAS AND ELECTRIC	OS	6	N/A	N/A	N/A
25	SEATTLE CITY LIGHT	OS	6	N/A	N/A	N/A
26	SEMPRA ENERGY TRADING CORP	OS	6	N/A	N/A	N/A
27	SOUTHERN CALIFORNIA EDISON COMPANY	OS	6	N/A	N/A	N/A
28	TACOMA POWER	OS	6	N/A	N/A	N/A
29	TRANSALTA ENERGY MARKETING	OS	6	N/A	N/A	N/A
30	TURLOCK IRRIGATION DISTRICT	OS	6	N/A	N/A	N/A
31	WESTERN AREA POWER ADMINISTRATION	OS	6	N/A	N/A	N/A
32						
33	Subtotal					
34						
35	BILATERAL CONTRACTS:					
36	- SUPPLEMENTAL ENERGY:					
37						
38	MIRANT	OS	6	N/A	N/A	N/A
39	WITHHOLDINGS FROM CALPINE (7)			N/A	N/A	N/A
40						
41	Subtotal					
42						
43						
44						
45						
46						
47						
48						
49						
50						

Name of Respondent	This Report Is:	Date of Report	Year of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) *An Original (2) A Resubmission	(Mo, Da, Yr)	End of 2009/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

Megawatthours Purchased (g)	POWER EXCHANGES: Megawatthours Received (h)	POWER EXCHANGES: Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
							1
							2
							3
138,712				5,552,297		5,552,297	4
400				14,300		14,300	5
30,785				1,050,079		1,050,079	6
89,024				3,977,006		3,977,006	7
350,055				12,464,140		12,464,140	8
8,822				375,970		375,970	9
86,100				3,117,313		3,117,313	10
175,250				5,406,640		5,406,640	11
						-	12
48,620				1,742,203		1,742,203	13
2,117,000				74,537,589		74,537,589	14
11,185				342,615		342,615	15
						-	16
1,725				74,320		74,320	17
437,230				17,761,541		17,761,541	18
(14)				(140)		(140)	19
990				33,840		33,840	20
2,000				74,440		74,440	21
74,683				2,576,638		2,576,638	22
3,000				96,510		96,510	23
(88)				48,225		48,225	24
14,860				569,570		569,570	25
1,581,490				62,650,755		62,650,755	26
314,595				7,987,476		7,987,476	27
890				25,640		25,640	28
249,829				9,619,705		9,619,705	29
37,595				1,467,282		1,467,282	30
3,396				141,649		141,649	31
							32
9,350,775	-	-	-	347,177,777	-	347,177,777	33
							34
							35
							36
							37
-			14,532,361			14,532,361	38
						-	39
							40
-	-	-	14,532,361	-	-	14,532,361	41
							42
							43
							44
							45
							46
							47
							48
							49
							50

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) *An Original (2) A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1						
2	BILATERAL CONTRACTS:					
3	- RESOURCE ADEQUACY:					
4						
5	CALIFORNIA POWER HOLDINGS	OS	6	N/A	N/A	N/A
6	CALPINE ENERGY SERVICES	OS	6	N/A	N/A	N/A
7	CALPINE GEYSERS	OS	6	N/A	N/A	N/A
8	CALPINE LOS MEDANOS	OS	6	N/A	N/A	N/A
9	ELK HILLS POWER	OS	6	N/A	N/A	N/A
10	MIRANT	OS	6	N/A	N/A	N/A
11	MORGAN STANLY CAPITAL	OS	6	N/A	N/A	N/A
12	NRG POWER MARKETING	OS	6	N/A	N/A	N/A
13	RELIANT ENERGY	OS	6	N/A	N/A	N/A
14	SAN DIEGO GAS & ELECTRIC	OS	6	N/A	N/A	N/A
15	SHELL ENERGY	OS	6	N/A	N/A	N/A
16	SOUTHERN CALIFORNIA EDISON	OS	6	N/A	N/A	N/A
17	CALPINE METCALF	OS	6	N/A	N/A	N/A
18						
19	Subtotal					
20						
21	BILATERAL CONTRACTS:					
22	- PHYSICAL CALL OPTIONS					
23						
24	CALPINE ENERGY SERVICES	OS	6	N/A	N/A	N/A
25	IBERDROLA RENEWABLES	OS	6	N/A	N/A	N/A
26	J. ARON	OS	6	N/A	N/A	N/A
27	NEXTERA ENERGY	OS	6	N/A	N/A	N/A
28	OCCIDENTAL POWER	OS	6	N/A	N/A	N/A
29	POWEREX	OS	6	N/A	N/A	N/A
30	SHELL ENERGY	OS	6	N/A	N/A	N/A
31						
32	Subtotal					
33						
34	BILATERAL CONTRACTS:					
35	- LONG-TERM WHOLESALE GENERATORS					
36						
37	DYNEGY	OS	6	N/A	N/A	N/A
38	JR SIMPLOT	OS	6	N/A	N/A	N/A
39	MIRANT TOLLING	OS	6	N/A	N/A	N/A
40	PANOCHE	OS	6	N/A	N/A	N/A
41	STARWOOD POWER MIDWAY	OS	6	N/A	N/A	N/A
42	TRIDAM DONNELLS POWERHOUSE	OS	6	N/A	N/A	N/A
43						
44	Subtotal					
45						
46						
47						
48						
49						

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) *An Original (2) A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report End of 2009/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
							1
							2
							3
							4
-			215,110			215,110	5
-			2,815,930			2,815,930	6
-			15,108,084			15,108,084	7
-			20,720,000			20,720,000	8
-			760,000			760,000	9
-			33,152,800			33,152,800	10
-			275,000			275,000	11
-			183,000			183,000	12
-			2,344,150			2,344,150	13
-			240,000			240,000	14
-			758,350			758,350	15
-			341,250			341,250	16
-			21,941,000			21,941,000	17
							18
-	-	-	98,854,674	-	-	98,854,674	19
							20
							21
							22
							23
-			262,500			262,500	24
-			690,000			690,000	25
-			1,038,000			1,038,000	26
-			435,000			435,000	27
-			1,132,500			1,132,500	28
-			465,000			465,000	29
-			555,000			555,000	30
							31
-	-	-	4,578,000	-	-	4,578,000	32
							33
							34
							35
							36
704,402			85,843,781	4,304,765		90,148,546	37
984				31,099		31,099	38
419,511			49,729,200	(18,370,965)		31,358,235	39
152,863			36,755,973	2,042,399		38,798,372	40
25,125			8,950,134	218,557		9,168,691	41
(364)				706,549		706,549	42
							43
1,302,521	-	-	181,279,088	(11,067,596)	-	170,211,492	44
							45
							46
							48
							49

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Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) *An Original (2) A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	BILATERAL CONTRACTS:					
2	- DEMAND RESPONSE AGREEMENTS:					
3						
4	ALTERNATIVE ENERGY RESOURCES	OS	6	N/A	N/A	N/A
5	CDWR	OS	6	N/A	N/A	N/A
6	C POWERED	OS	6	N/A	N/A	N/A
7	ENERGY CONNECT	OS	6	N/A	N/A	N/A
8	ENERGY CURTAILMENT	OS	6	N/A	N/A	N/A
9	ENERNOC	OS	6	N/A	N/A	N/A
10	GST FX GAIN (LOSS)			N/A	N/A	N/A
11						
12	Subtotal					
13						
14	BILATERAL CONTRACTS:					
15	- OTHERS:					
16						
17	HEDGING ACTIVITY			N/A	N/A	N/A
18	NON-UEG FUEL COSTS (9)			N/A	N/A	N/A
19	DWR PORTION OF SURPLUS SALES TO WSPP/EEI			N/A	N/A	N/A
20	BROKER/MANAGEMENT AND OTHER FEES			N/A	N/A	N/A
21	GAS BROKER FEES ADJUSTMENT			N/A	N/A	N/A
22	INTERSTATE GAS PIPELINE CHARGES FOR EGS			N/A	N/A	N/A
23	OTHERS			N/A	N/A	N/A
24						
25	Subtotal					
26						
27	ISO AND OTHERS:					
28						
29	CALIFORNIA INDEPENDENT SYSTEM					
30	OPERATOR (ISO) PURCHASES, OTHERS (8)			N/A	N/A	N/A
31	DWR PORTION OF ISO SPOT MARKET SALES			N/A	N/A	N/A
32	MISCELLANEOUS ITEMS (5)			N/A	N/A	N/A
33				N/A	N/A	N/A
34						
35	TOTAL PURCHASED POWER					
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49						

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

Megawatthours Purchased (g)	POWER EXCHANGES: Megawatthours Received (h)	POWER EXCHANGES: Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j + k + l) or Settlement ($) (m)	Line No.
							1
							2
							3
-			3,026,136	72,597		3,098,733	4
-			(2,310,000)			(2,310,000)	5
-			113,400	12,141		125,541	6
-			1,464,484	12,427		1,476,911	7
-			2,343,572	31,431		2,375,003	8
-			3,285,400	49,021		3,334,421	9
-					(15,026)	(15,026)	10
							11
-	-	-	7,922,992	177,617	(15,026)	8,085,583	12
							13
							14
							15
							16
					656,645,549	656,645,549	17
					51,415,585	51,415,585	18
28,708				879,864		879,864	19
					994,900	994,900	20
						-	21
			1,033,666			1,033,666	22
					802,358	802,358	23
							24
28,708	-	-	1,033,666	879,864	709,858,392	711,771,922	25
							26
							27
							28
							29
10,168,836				498,242,198		498,242,198	30
140,037				4,857,904		4,857,904	31
					1,035,111	1,035,111	32
							33
							34
44,606,569	**0**	**0**	**737,104,643**	**2,042,841,619**	**710,791,061**	**3,490,737,323**	35
							36
							37
							38
							39
CHECK						CHECK	40
44,606,569						3,490,737,323	41
							42
-		Difference				(0)	43
							44
-			-	-			45
							46
							47
							48
							49

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PURCHASED POWER (Account 555)
(Including power exchanges)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)

Footnotes:

(1) The CPUC in D.00-04-020 approved a settlement that would terminate a 1981 power-purchase agreement between the Utility an d East Bay Municipal Utility District ("EBMUD"). Under this settlement, EBMUD would make payments estimated at $7.6 million to be credited to Utility ratepayers over an eight-year period. During 2009, the Utility received $87,416 under this settlement.

(2) Not used.

(3) No FERC rate schedules are provided in column (c) for QF's and Independent Power Producers because these companies are non-FERC jurisdictional sellers.

(4) An average monthly billing demand, column (d), is shown for those QF's with firm capacity commitments.

(5) These expenses consist of Transmission Service Costs related to power losses, PX Admin Fees, Circuit Leases, Other Consulting Services (Independent Evaluator costs), and miscellaneous expenses.

(6) The following is a list of QF's under 1 MW:

1080 CHESTNUT CORP.
AIRPORT CLUB
AMERICAN ENERGY, INC. (SAN LUIS BYPASS)
AMERICAN ENERGY, INC. (WOLFSEN BYPASS)
ARBUCKLE MOUNTAIN HYDRO
ARDEN WOOD BENEVOLENT ASSOC.
BAILEY CREEK RANCH
BROWNS VALLEY IRRIGATION DISTRICT
CALAVERAS YUBA HYDRO #1
CALAVERAS YUBA HYDRO #2
CALAVERAS YUBA HYDRO #3
CANAL CREEK POWER PLANT (RETA)
CHARCOAL RAVINE
CITY OF FAIRFIELD
CITY OF MILPITAS
CITY OF WATSONVILLE
COUNTY OF SANTA CRUZ (WATER ST. JAIL)
COVANTA POWER PACIFIC, STOCKTON
DAVID O. HARDE
DIGGER CREEK RANCH
DOLE ENTERPRISES, INC
DONALD R. CHENOWETH
E J M MCFADDEN
EAGLE HYDRO
ERIC AND DEBBIE WATTENBURG
FAIRFIELD POWER PLANT (PAPAZIAN)
FAR WEST POWER CORPORATION
FIVE BEARS HYDROELECTRIC
GAS RECOVERY SYSTEMS, INC [SANTA CRUZ]
GREATER VALLEJO RECREATION DISTRICT
HAT CREEK HEREFORD RANCH
HAYWARD AREA REC & PARK DIST.
HENWOOD ASSOCIATES
JACKSON VALLEY IRRIGATION DIST
JAMES B. PETER
JAMES CRANE HYDRO
JOHN NEERHOUT JR.
KAREN RIPPEY
KINGS RIVER HYDRO CO.
L.P. REINHARD
LANGERWERF DAIRY
LASSEN STATION HYDRO
LOFTON RANCH
MADERA CANAL (1174 + 84)
MADERA CANAL (1923)
MADERA CANAL STATION 1302
MEGA HYDRO #1 (CLOVER CREEK)
MEGA HYDRO (GOOSE VALLEY RANCH)
MEGA RENEWABLES (SILVER SPRINGS)
MICHAEL W. STEPHENS
MILL & SULPHUR CREEK
NID/COMBIE NORTH
NID/SCOTTS FLAT
NIHONMACHI TERRACE
OCCIDENTAL OF ELK HILLS
ORANGE COVE IRRIGATION DIST.
ORINDA SENIOR VILLAGE
PAN PACIFIC (WEBER FLAT)
PLACER COUNTY WATER AGENCY
REAL GOODS TRADING CORP.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) *An Original (2) A Resubmission		End of 2009/Q4

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

Megawatthours Purchased (g)	POWER EXCHANGES Megawatthours Received (h)	Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.

Footnotes (continued):

(6) QF's under 1 MW (continued):

RED BLUFF UNION HIGH SCHOOL
ROBERT AND JOYCE VIEUX
ROBERT W. LEE
ROBIN WILLIAMS SOLAR POWER GEN
ROCK CREEK WATER DISTRICT
SANTA CLARA VALLEY WATER DIST.
SATELLITE SENIOR HOMES
SCHAADS HYDRO
SHAMROCK UTILITIES (CEDAR FLAT)
SHAMROCK UTILITIES (CLOVER LEAF)
SHEILA ST. GERMAIN
SIERRA ENERGY
SNOW MOUNTAIN HYDRO LLC (LOST CREEK 2)
SOUTH SUTTER WATER
STANFORD ENERGY GROUP
STEVE & BONNIE TETRICK
STEVEN SPELLENBERG HYDRO
SUTTER'S MILL
SWISS AMERICA
TOM BENNINGHOVEN
UCSC PHYSICAL PLANT
VECINO VINEYARDS LLC
WATER WHEEL RANCH
WINEAGLE DEVELOPERS 1
WRIGHT RANCH HYDROELECTRIC
YOUNG RADIO INC.
YOUTH WITH A MISSION/SPRINGS OF LIVING WATERS
YUBA CITY RACQUET CLUB
YUBA COUNTY WATER AGENCY

(7) NOT USED IN 2009.

(8) This includes California ISO charges. NOT USED IN 2009.

(9) The Non-UEG (Non Utility Electric Generation) fuel costs is gas purchased for the bilateral contracts (tolling agreements) with LSP Morro Bay, LSP Moss Landing, and Mirant Pittsburg and Contra Costa.

Name of Company or Public Authority	MWHs Purchased	Capacity Pay ($)	Energy Pay ($)	Total ($)	Avg. Price ($/MWH)
QUALIFYING FACILITIES (QF's)					
WASTE TO ENERGY					
MONTEREY REGIONAL WASTE MGMT DIST.	23,338	143,903	2,094,071	2,237,974	
MONTEREY REGIONAL WATER	256	2,055	12,367	14,422	
COVANTA POWER PACIFIC (SALINAS)	5,693	69,187	256,043	325,230	
COVANTA POWER PACIFIC (STOCKTON)	5,649	53,703	245,895	299,598	
EBMUD (OAKLAND)	2,739	42,310	93,386	135,696	
GAS RECOVERY SYS. (AMERICAN CYN)	6,983	162,353	463,799	626,152	
GAS RECOVERY SYS. (GUADALUPE)	17,938	293,251	1,185,763	1,479,014	
GAS RECOVERY SYS. (MENLO PARK)	9,277	(76,039)	613,376	537,337	
GAS RECOVERY SYS. (NEWBY ISLAND 1)				-	
GAS RECOVERY SYS. (NEWBY ISLAND 2)	32,973	560,899	2,194,639	2,755,538	
PALO ALTO LANDFILL				-	
STANISLAUS WASTE ENERGY CO.	141,945	2,964,647	9,282,788	12,247,435	
WASTE MANAGEMENT RENEWABLE ENERGY	42,280	214,099	2,792,880	3,006,979	
BIOMASS					
BIG VALLEY POWER LLC	1,581	123,313	114,528	237,841	
BURNEY FOREST PRODUCTS	228,153	5,751,043	14,719,047	20,470,090	
COLLINS PINE	46,348	812,545	2,957,603	3,770,148	
DG FAIRHAVEN POWER, LLC	108,712	2,572,682	6,150,147	8,722,829	
HL POWER	162,502	3,747,562	7,338,946	11,086,508	
COVANTA MENDOTA L. P.	190,138	4,909,074	12,676,634	17,585,708	
OGDEN POWER PACIFIC, INC. (BURNEY)	57,059	1,468,060	2,638,835	4,106,895	
OGDEN POWER PACIFIC, INC. (CHINESE STATION)	126,884	3,009,142	8,395,724	11,404,866	
OGDEN POWER PACIFIC, INC.(MT. LASSEN)	55,720	1,556,377	2,574,315	4,130,692	
OGDEN POWER PACIFIC, INC. (OROVILLE)	129,702	2,498,236	8,506,525	11,004,761	
RIO BRAVO FRESNO	185,959	4,805,120	12,248,972	17,054,092	
RIO BRAVO ROCKLIN	183,080	4,914,741	12,043,882	16,958,623	
SIERRA PACIFIC IND. (ANDERSON)	8,987	38,746	385,998	424,744	
SIERRA PACIFIC IND. (BURNEY)	88,352	1,839,750	5,696,492	7,536,242	
SIERRA PACIFIC IND. (LINCOLN)	87,255	1,580,890	5,682,752	7,263,642	
SIERRA PACIFIC IND. (QUINCY)	118,464	2,438,955	7,664,535	10,103,490	
SIERRA PACIFIC IND.(SONORA)	17,913	376,194	1,132,900	1,509,094	
THERMAL ENERGY DEV. CORP.	141,495	3,071,148	9,299,306	12,370,454	
TOWN OF SCOTIA COMPANY, LLC (PACIFIC LUMBER)	73,045	-	7,758,354	7,758,354	
WADHAM ENERGY LTD. PART.	-	101,029	-	101,029	
WHEELABRATOR SHASTA	395,731	8,993,428	25,869,196	34,862,624	
WOODLAND BIOMASS	162,696	4,622,680	7,471,153	12,093,833	
RENEWABLE: GEOTHERMAL					
AMEDEE GEOTHERMAL VENTURE 1	3,975	33,349	163,022	196,371	
RENEWABLE: WIND					
ALTAMONT ENERGY CORP				-	
ALTAMONT MIDWAY LTD.	14,100	247,008	518,631	765,639	
ALTAMONT POWER LLC (PARTNERS 1)					
ALTAMONT POWER LLC (PARTNERS 2)				-	
ALTAMONT POWER LLC (3-4)	7,596	127,451	459,783	587,234	
ALTAMONT POWER LLC (4-4)	32,844	556,022	1,976,034	2,532,056	
ALTAMONT POWER LLC (6-4)	29,339	529,491	1,772,406	2,301,897	
GREEN RIDGE POWER LLC (10 MW)	20,212	424,995	1,195,057	1,620,052	
GREEN RIDGE POWER LLC (100 MW - A)	87,675	1,807,463	5,316,795	7,124,258	
GREEN RIDGE POWER LLC (100 MW - B)				-	
GREEN RIDGE POWER LLC (100 MW - C)	11,533	258,353	697,195	955,548	
GREEN RIDGE POWER LLC (100 MW - D)	18,192	376,311	1,102,176	1,478,487	
GREEN RIDGE POWER LLC (110 MW)	288,283	5,366,672	16,558,339	21,925,011	
GREEN RIDGE POWER LLC (23.8 MW)	19,172	319,403	1,136,303	1,455,706	
GREEN RIDGE POWER LLC (30 MW)					
GREEN RIDGE POWER LLC (5.9 MW)	12,065	257,187	730,744	987,931	
GREEN RIDGE POWER LLC (70 MW - A)				-	
GREEN RIDGE POWER LLC (70 MW - B)	20,583	541,619	1,206,948	1,748,567	
GREEN RIDGE POWER LLC (70 MW - C)	31,911	827,291	1,868,615	2,695,906	
GREEN RIDGE POWER LLC (70 MW - D)	1,669	43,819	97,875	141,694	
GREEN RIDGE POWER LLC (70 MW)	92,670	1,945,901	5,594,019	7,539,920	
INTERNATIONAL TURBINE RESEARCH	26,198	567,051	1,634,188	2,201,239	
J.V.ENTERPRISE				-	
NORTHWIND ENERGY	15,480	270,857	952,591	1,223,448	
PATTERSON PASS WIND FARM LLC	40,654	740,053	2,485,488	3,225,541	
SEA WEST ENERGY GROUP (TOTALS)	11,712	192,901	426,749	619,650	
TRES VAQUEROS WIND FARMS, LLC	11,650	179,398	633,847	813,245	

Name of Company or Public Authority	MWHs Purchased	Capacity Pay ($)	Energy Pay ($)	Total ($)	Avg. Price ($/MWH)
RENEWABLE: HYDRO					
BAKER STATION ASSOCIATES L.P.	2,622	32,344	136,544	168,888	
CALAVERAS CTY WD	5,052	79,103	188,111	267,214	
EL DORADO (MONTGOMERY CK)	6,284	80,297	444,133	524,430	
FRIANT POWER AUTHORITY	100,525	2,579,427	6,020,138	8,599,565	
HAYPRESS HYDROELECTRIC, INC. (LWR)	7,444	171,523	460,736	632,259	
HAYPRESS HYDROELECTRIC, INC. (MDL)	7,393	153,187	472,058	625,245	
HUMBOLDT BAY MWD	3,926	21,567	247,995	269,562	
HYPOWER, INC.	31,004	349,386	1,347,724	1,697,110	
INDIAN VALLEY HYDRO	1,330	10,953	76,931	87,884	
KERN HYDRO (OLCESE)	32,203	266,552	1,951,884	2,218,436	
MADERA-CHOWCHILLA WATER AND POWER AUTHORITY	5,331	138,654	315,455	454,109	
MALACHA HYDRO L.P.	31,704	1,557,180	2,265,056	3,822,236	
MEGA RENEWABLES (BIDWELL DITCH)	11,171	205,234	501,380	706,614	
MEGA RENEWABLES (HATCHET CRK)	12,280	166,167	588,239	754,406	
MEGA RENEWABLES (ROARING CRK)	3,646	45,939	179,109	225,048	
MERCED ID (PARKER)	5,977	82,579	207,160	289,739	
MONTEREY CTY WATER RES AGENCY	10,868	143,932	472,476	616,408	
NELSON CREEK POWER INC.	2,156	29,736	149,405	179,141	
NEVADA IRRIGATION DISTRICT/BOWMAN HYROELECTRIC	12,672	290,722	769,208	1,059,930	
NID/COMBIE SOUTH	4,907	20,123	335,235	355,358	
NID/SCOTTS FLAT	3,272	27,227	193,138	220,365	
NORMAN ROSS BURGESS	5,655	89,269	278,840	368,109	
OLSEN POWER PARTNERS	4,361	61,653	190,956	252,609	
ORANGE COVE IRRIGATION DIST.				-	
ROCK CREEK L.P.	1,321	17,080	92,717	109,797	
SNOW MOUNTAIN HYDRO LLC (BURNEY CREEK)	3,894	51,845	270,664	322,509	
SNOW MOUNTAIN HYDRO LLC (COVE)	9,641	122,919	665,330	788,249	
SNOW MOUNTAIN HYDRO LLC (LOST CREEK 1)	5,031	22,953	308,180	331,133	
SNOW MOUNTAIN HYDRO LLC (LOST CREEK 2)	2,473	11,947	163,941	175,888	
SNOW MOUNTAIN HYDRO LLC (PONDEROSA BAILEY CREE	1,212	28,902	63,554	92,456	
SONOMA COUNTY WATER AGENCY	8,143	145,261	342,555	487,816	
SOUTH SAN JOAQUIN ID (FRANKENHEIMER)	15,265	208,617	574,407	783,024	
SOUTH SAN JOAQUIN ID (WOODWARD)	5,470	79,255	200,648	279,903	
STS HYDROPOWER LTD. (KANAKA)	771	9,125	54,408	63,533	
STS HYDROPOWER LTD. (KEKAWAKA)	5,157	17,416	373,131	390,547	
TKO POWER (SOUTH BEAR CREEK)	1,826	13,835	132,777	146,612	
TRI-DAM AUTHORITY	86,859	2,628,313	3,446,308	6,074,621	
YOLO COUNTY FLOOD & WCD				-	
YUBA COUNTY WATER (DEADWOOD CREEK)	1,792	25,467	124,386	149,853	
SMALL POWER PRODUCERS - RENEWABLE(6)	49,898	734,980	2,706,622	3,441,602	
TOTAL OF ALL 2009 QF RENEWABLES	**4,166,896**	**89,994,347**	**254,399,195**	**344,393,542**	82.65
RENEWABLE BILATERAL CONTRACTS:					
ARLINGTON WIND POWER PROJECT	229,929		23,119,616	23,119,616	
BONNEVILLE POWER ADMINSTRATION (KLONDIKE IIIA)	-		547,238	547,238	
BOTTLE ROCK	88,310		6,141,951	6,141,951	
BUCKEYE HYDROELECTRIC PROJECT	3,234		324,796	324,796	
BUENA VISTA ENERGY, LLC	101,080		5,637,896	5,637,896	
CALPINE GEYSERS	3,316,890		178,677,571	178,677,571	
CASTELANELLI BROS. BIOGAS	710		74,467	74,467	
COMMUNITY RENEWABLE ENERGY SERVICES, INC	61,776	1,410,150	2,708,189	4,118,339	
ETIWANDA POWER PLANT	28,664		1,381,161	1,381,161	
FPLE DIABLO WINDS	64,149		2,786,649	2,786,649	
GLOBAL AMPERSAND	97,361		7,492,563	7,492,563	
IBERDROLA KLONDIKE (AKA PPM KLONDIKE)	451,154		30,726,961	30,726,961	
IBERDROLA RENEWABLES (AKA PPM ENERGY)	-		4,206,773	4,206,773	
MADERA RENEWABLE	134,604	2,080,939	6,098,839	8,179,778	
NEVADA IRRIGATION DISTRICT NORTH COMBIE	223		21,871	21,871	
PACIFICORP	220,825		15,448,246	15,448,246	
SEMPRA EL DORADO SOLAR IMPORT	21,668		3,516,074	3,516,074	
SHELL ENERGY	131,640		9,239,279	9,239,279	
SHILOH	377,342		32,400,629	32,400,629	
SHILOH I WIND PROJECT LLC	197,396		10,928,986	10,928,986	
SIERRA POWER CORPORATION	43,677	996,386	1,978,479	2,974,865	
WADHAM ENERGY LTD	173,588		14,481,533	14,481,533	
Subtotal	**5,744,220**	4,487,475	**357,939,767**	**362,427,242**	63.09

PACIFIC GAS AND ELECTRIC COMPANY
Direct Access Reopening OIR
Rulemaking 07-05-025
Data Response

PG&E Data Request No.:	ED_001-02		
PG&E File Name:	DirectAccessReopeningOIR_DR_ED_001-Q02		
Request Date:	December 14, 2010	Requester DR No.:	ED_DR001
Date Sent:	December 22, 2010	Requesting Party:	Steve Roscow
PG&E Witness:	Donna Barry	Requester:	Energy Division on behalf of Joint Parties

QUESTION 2

Provide an IOU CRS Spreadsheet

a. Sensitivity of MPB/IR to Capacity Proposal

b. Sensitivity of MPB/IR to pre-2003 RPS-eligible removal/inclusion

c. Adjust MPB for Gen profile (On/Off)

d. Impact of removal ISO costs (load-related / net short) from total portfolio

ANSWER 2

The requested analysis for 2.a, 2.c, and 2.d is included in the attached spreadsheet.

With respect to question 2.b, the sensitivity of the indifference rate with RPS-eligible generation (and cost) removed is the same request as Question 5 and a confidential response is being provided to Energy Division.

That said, the sensitivity of the indifference rate as a result of adding a renewable adjustment to the benchmark that reflects the renewable generation (pre-2003 and post-2003 generation) in the total portfolio is provided in the attachment to this question.

Line No.	November ERRA Update - Table 7-4 and 7-5		D.04-12-048 PCIA			
	Forecast Indifference Amount					
	2011 Annual ERRA Forecast - November Update with AET CTC RRQ		2009 Vintage	2010 Vintage	2011 Vintage	
1	Total Portfolio Generation at generator (GWh)		72,013	72,960	72,960	1
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)		67,692	68,582	68,582	2
3	Total Portfolio Cost ($1000)		$4,517,148	$4,646,766	$4,646,766	3
4	Benchmark ($/MWh)	$42.42				4
5	Market Cost ($1000)		$2,871,217	$2,908,994	$2,908,994	5
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)		$1,645,932	$1,737,772	$1,737,772	6
7						7
8	**Indifference Results, current year (excludes ff&u) ($1000)**		$1,645,932	$1,737,772	$1,737,772	8
9	2010 Cummulative Indifference Amount		$ -	$ -	$ -	9
10	2011 Cumulative Indifference Amount (prior year(s) + current year results)		$ 1,645,932	$ 1,737,772	$ 1,737,772	10
11	2011 Cumulative Indifference Amount w/ ff&u		$ 1,662,811	$ 1,755,593	$ 1,755,593	11
12	Ongoing CTC Cost RRQ ($1000)		$ 552,136	$ 552,136	$ 552,136	12
13	Ongoing CTC - EOY MTCBA Balance ($1000)		$ -	$ -	$ -	13
14	PCIA RRQ ($1000) = Line 11 - (Line 12 + Line 13)		$ 1,110,675	$ 1,203,457	$ 1,203,457	14
15	PCIA RRQ w/o Uncollectibles ($1000)		$ 1,107,808	$ 1,200,350	$ 1,200,350	15
16	**franchise fees and uncollectibles factor**	0.010255				16
17	**franchise fees factor**	0.007647				17
	Simple Average PCIA ($/kWh)		0.01386	0.01531	0.01561	

Line No.	Cumulative Adjusted Benchmark		$50.92	$51.15	$51.15	
	Forecast Indifference Amount		D.04-12-048 PCIA			
	2011 Annual ERRA Forecast - November Update with AET CTC RRQ		2009 Vintage	2010 Vintage	2011 Vintage	
1	Total Portfolio Generation at generator (GWh)		72,013	72,960	72,960	1
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)		67,692	68,582	68,582	2
3	Total Portfolio Cost ($1000) less ISO Load Related Costs		$ 4,454,612	$ 4,583,407	$ 4,583,407	3
4	Benchmark ($/MWh)	see adj BM				4
5	Market Cost ($1000)		$ 3,447,060	$ 3,508,016	$ 3,508,016	5
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)		$ 1,007,552	$ 1,075,391	$ 1,075,391	6
7						7
8	**Indifference Results, current year (excludes ff&u) ($1000)**		$1,007,552	$1,075,391	$1,075,391	8
9	2010 Cummulative Indifference Amount		$ -	$ -	$ -	9
10	2011 Cumulative Indifference Amount (prior year(s) + current year results)		$ 1,007,552	$ 1,075,391	$ 1,075,391	10
11	2011 Cumulative Indifference Amount w/ ff&u		$ 1,017,884	$ 1,086,419	$ 1,086,419	11
12	Ongoing CTC Cost RRQ ($1000)		$ 457,164	$ 457,164	$ 457,164	12
13	Ongoing CTC - EOY MTCBA Balance ($1000)		$ -	$ -	$ -	13
14	PCIA RRQ ($1000) = Line 11 - (Line 12 + Line 13)		$ 560,720	$ 629,255	$ 629,255	14
15	PCIA RRQ w/o Uncollectibles ($1000)		$ 559,272	$ 627,630	$ 627,630	15
16	**franchise fees and uncollectibles factor**	0.010255				16
17	**franchise fees factor**	0.007647				17

Change in PCIA RRQ	(548,535)	(572,720)	(572,720)
New Simple Average PCIA ($/kWh)	0.00700	0.00801	0.00816
Cumulative Change as a result of All Adjustments	(0.00686)	(0.00731)	(0.00745)
Percent Change	-49.5%	-47.7%	-47.7%

November ERRA Update - Table 7-4 and 7-5

Line No.	Forecast Indifference Amount		D.04-12-048 PCIA			
	2011 Annual ERRA Forecast - November Update with AET CTC RRQ		**2009 Vintage**	**2010 Vintage**	**2011 Vintage**	
1	Total Portfolio Generation at generator (GWh)		72,013	72,960	72,960	1
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)		67,692	68,582	68,582	2
3	Total Portfolio Cost ($1000)		$4,517,148	$4,646,766	$4,646,766	3
4	Benchmark ($/MWh)	$42.42				4
5	Market Cost ($1000)		$2,871,217	$2,908,994	$2,908,994	5
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)		$1,645,932	$1,737,772	$1,737,772	6
7						7
8	**Indifference Results, current year (excludes ff&u) ($1000)**		$1,645,932	$1,737,772	$1,737,772	8
9	2010 Cummulative Indifference Amount		$ -	$ -	$ -	9
10	2011 Cumulative Indifference Amount (prior year(s) + current year results)		$ 1,645,932	$ 1,737,772	$ 1,737,772	10
11	2011 Cumulative Indifference Amount w/ ff&u		$ 1,662,811	$ 1,755,593	$ 1,755,593	11
12	Ongoing CTC Cost RRQ ($1000)		$ 552,136	$ 552,136	$ 552,136	12
13	Ongoing CTC - EOY MTCBA Balance ($1000)		$ -	$ -	$ -	13
14	PCIA RRQ ($1000) = Line 11 - (Line 12 + Line 13)		$ 1,110,675	$ 1,203,457	$ 1,203,457	14
15	PCIA RRQ w/o Uncollectibles ($1000)		$ 1,107,808	$ 1,200,350	$ 1,200,350	15
16	**franchise fees and uncollectibles factor**	0.010255				16
17	**franchise fees factor**	0.007647				17

Simple Average PCIA ($/kWh)	0.01386	0.01531	0.01561

Adjust Bencmark for Capacity cost	**$ 3.91**	**$ 3.91**	**$ 3.91**
Old Capacity Cost	$ (4.24)	$ (4.24)	$ (4.24)
New Capacity Cost	$ 8.15	$ 8.15	$ 8.15
Adjusted Benchmark	**$46.33**	**$46.33**	**$46.33**

Line No.	Forecast indifference Amount		D.04-12-048 PCIA			
	2011 Annual ERRA Forecast - November Update with AET CTC RRQ		**2009 Vintage**	**2010 Vintage**	**2011 Vintage**	
1	Total Portfolio Generation at generator (GWh)		72,013	72,960	72,960	1
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)		67,692	68,582	68,582	2
3	Total Portfolio Cost ($1000)		$ 4,517,148	$ 4,646,766	$ 4,646,766	3
4	Benchmark ($/MWh)	see adj BM				4
5	Market Cost ($1000)		$ 3,136,086	$ 3,177,348	$ 3,177,348	5
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)		$ 1,381,062	$ 1,469,418	$ 1,469,418	6
7						7
8	**Indifference Results, current year (excludes ff&u) ($1000)**		$1,381,062	$1,469,418	$1,469,418	8
9	2010 Cummulative Indifference Amount		$ -	$ -	$ -	9
10	2011 Cumulative Indifference Amount (prior year(s) + current year results)		$ 1,381,062	$ 1,469,418	$ 1,469,418	10
11	2011 Cumulative Indifference Amount w/ ff&u		$ 1,395,225	$ 1,484,486	$ 1,484,486	11
12	Ongoing CTC Cost RRQ ($1000)		$ 490,453	$ 490,453	$ 490,453	12
13	Ongoing CTC - EOY MTCBA Balance ($1000)		$ -	$ -	$ -	13
14	PCIA RRQ ($1000) = Line 11 - (Line 12 + Line 13)		$ 904,772	$ 994,033	$ 994,033	14
15	PCIA RRQ w/o Uncollectibles ($1000)		$ 902,436	$ 991,467	$ 991,467	15
16	**franchise fees and uncollectibles factor**	0.010255				16
17	**franchise fees factor**	0.007647				17

Change in PCIA RRQ	(205,372)	(208,883)	(208,883)
New Simple Average PCIA ($/kWh)	0.01129	0.01265	0.01290
Change as a result of updating capacity adder	(0.00257)	(0.00266)	(0.00272)
Percent Change	-18.5%	-17.4%	-17.4%

TBS Capacity Scalar 1.29

November ERRA Update - Table 7-4 and 7-5

Line No.	Forecast Indifference Amount		D.04-12-048 PCIA			
	2011 Annual ERRA Forecast - November Update with AET CTC RRQ		**2009 Vintage**	**2010 Vintage**	**2011 Vintage**	
1	Total Portfolio Generation at generator (GWh)		72,013	72,960	72,960	1
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)		67,692	68,582	68,582	2
3	Total Portfolio Cost ($1000)		$4,517,148	$4,646,766	$4,646,766	3
4	Benchmark ($/MWh)	$42.42				4
5	Market Cost ($1000)		$2,871,217	$2,908,994	$2,908,994	5
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)		$1,645,932	$1,737,772	$1,737,772	6
7						7
8	**Indifference Results, current year (excludes ff&u) ($1000)**		$1,645,932	$1,737,772	$1,737,772	8
9	2010 Cummulative Indifference Amount		$ -	$ -	$ -	9
10	2011 Cumulative Indifference Amount (prior year(s) + current year results)		$ 1,645,932	$ 1,737,772	$ 1,737,772	10
11	2011 Cumulative Indifference Amount w/ ff&u		$ 1,662,811	$ 1,755,593	$ 1,755,593	11
12	Ongoing CTC Cost RRQ ($1000)		$ 552,136	$ 552,136	$ 552,136	12
13	Ongoing CTC - EOY MTCBA Balance ($1000)		$ -	$ -	$ -	13
14	PCIA RRQ ($1000) = Line 11 - (Line 12 + Line 13)		$ 1,110,675	$ 1,203,457	$ 1,203,457	14
15	PCIA RRQ w/o Uncollectibles ($1000)		$ 1,107,808	$ 1,200,350	$ 1,200,350	15
16	**franchise fees and uncollectibles factor**	0.010255				16
17	**franchise fees factor**	0.007647				17

Simple Average PCIA ($/kWh)	0.01386	0.01531	0.01561

Adjust Bencmark for renewable cost - RPS % in Portfolio	**17.95%**	**19.09%**	**19.09%**
Post 2003 Renewables %	12.41%	13.55%	13.55%
QF Renewables %	5.54%	5.54%	5.54%
Sm. Hydro % (no detailed unit-level data available last week for RPS-eligible URG)			
Adjust Bencmark for renewable cost ($/MWh adjustment) = RPS Preimum * RPS % in Po	**$ 3.59**	**$ 3.82**	**$ 3.82**
Post 2003 Renewables = REC Value * %	$ 2.48	$ 2.71	$ 2.71
QF Renewables = REC Value * %	$ 1.11	$ 1.11	$ 1.11
Sm. Hydro = REC Value * %	$ -	$ -	$ -
Adjusted Benchmark	**$46.01**	**$46.23**	**$46.23**

Line No.	Forecast Indifference Amount		D.04-12-048 PCIA			
	2011 Annual ERRA Forecast - November Update with AET CTC RRQ		**2009 Vintage**	**2010 Vintage**	**2011 Vintage**	
1	Total Portfolio Generation at generator (GWh)		72,013	72,960	72,960	1
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)		67,692	68,582	68,582	2
3	Total Portfolio Cost ($1000)		$ 4,517,148	$ 4,646,766	$ 4,646,766	3
4	Benchmark ($/MWh)					4
5	Market Cost ($1000)	see adj BM	$ 3,114,264	$ 3,170,841	$ 3,170,841	5
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)		$ 1,402,884	$ 1,475,925	$ 1,475,925	6
7						7
8	**Indifference Results, current year (excludes ff&u) ($1000)**		$1,402,884	$1,475,925	$1,475,925	8
9	2010 Cummulative Indifference Amount		$ -	$ -	$ -	9
10	2011 Cumulative Indifference Amount (prior year(s) + current year results)		$ 1,402,884	$ 1,475,925	$ 1,475,925	10
11	2011 Cumulative Indifference Amount w/ ff&u		$ 1,417,270	$ 1,475,925	$ 1,475,925	11
12	Ongoing CTC Cost RRQ ($1000)		$ 534,666	$ 534,666	$ 534,666	12
13	Ongoing CTC - EOY MTCBA Balance ($1000)		$ -	$ -	$ -	13
14	PCIA RRQ ($1000) = Line 11 - (Line 12 + Line 13)		$ 882,605	$ 941,259	$ 941,259	14
15	PCIA RRQ w/o Uncollectibles ($1000)		$ 880,326	$ 938,829	$ 938,829	15
16	**franchise fees and uncollectibles factor**	0.010255				16
17	**franchise fees factor**	0.007647				17

Change in PCIA RRQ	(225,203)	(259,091)	(259,091)
New Simple Average PCIA ($/kWh)	0.01102	0.01198	0.01221
Change as a result of adding RPS adder	(0.00285)	(0.00334)	(0.00340)
Percent Change	-20.5%	-21.8%	-21.8%

TBS Renew. Scalar 1.09

November ERRA Update - Table 7-4 and 7-5

Line No.	Forecast Indifference Amount		D.04-12-048 PCIA			
	2011 Annual ERRA Forecast - November Update with AET CTC RRQ		**2009 Vintage**	**2010 Vintage**	**2011 Vintage**	
1	Total Portfolio Generation at generator (GWh)		72,013	72,960	72,960	1
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)		67,692	68,582	68,582	2
3	Total Portfolio Cost ($1000)		$4,517,148	$4,646,766	$4,646,766	3
4	Benchmark ($/MWh)	$42.42				4
5	Market Cost ($1000)		$2,871,217	$2,908,994	$2,908,994	5
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)		$1,645,932	$1,737,772	$1,737,772	6
7						7
8	**Indifference Results, current year (excludes ff&u) ($1000)**		$1,645,932	$1,737,772	$1,737,772	8
9	2010 Cummulative Indifference Amount		$ -	$ -	$ -	9
10	2011 Cumulative Indifference Amount (prior year(s) + current year results)		$ 1,645,932	$ 1,737,772	$ 1,737,772	10
11	2011 Cumulative Indifference Amount w/ ff&u		$ 1,662,811	$ 1,755,593	$ 1,755,593	11
12	Ongoing CTC Cost RRQ ($1000)		$ 552,136	$ 552,136	$ 552,136	12
13	Ongoing CTC - EOY MTCBA Balance ($1000)		$ -	$ -	$ -	13
14	PCIA RRQ ($1000) = Line 11 - (Line 12 + Line 13)		$ 1,110,675	$ 1,203,457	$ 1,203,457	14
15	PCIA RRQ w/o Uncollectibles ($1000)		$ 1,107,808	$ 1,200,350	$ 1,200,350	15
16	**franchise fees and uncollectibles factor**	0.010255				16
17	**franchise fees factor**	0.007647				17
	Simple Average PCIA ($/kWh)		0.01386	0.01531	0.01561	

Line No.	Adjust Benchmark for portfolio peak generation		$43.42	$43.42	$43.42	
	Forecast Indifference Amount		D.04-12-048 PCIA			
	2011 Annual ERRA Forecast - November Update with AET CTC RRQ		**2009 Vintage**	**2010 Vintage**	**2011 Vintage**	
1	Total Portfolio Generation at generator (GWh)		72,013	72,960	72,960	1
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)		67,692	68,582	68,582	2
3	Total Portfolio Cost ($1000)		$ 4,517,148	$ 4,646,766	$ 4,646,766	3
4	Benchmark ($/MWh)	see adj BM				4
5	Market Cost ($1000)		$ 2,939,143	$ 2,977,814	$ 2,977,814	5
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)		$ 1,578,005	$ 1,668,952	$ 1,668,952	6
7						7
8	**Indifference Results, current year (excludes ff&u) ($1000)**		$1,578,005	$1,668,952	$1,668,952	8
9	2010 Cummulative Indifference Amount		$ -	$ -	$ -	9
10	2011 Cumulative Indifference Amount (prior year(s) + current year results)		$ 1,578,005	$ 1,668,952	$ 1,668,952	10
11	2011 Cumulative Indifference Amount w/ ff&u		$ 1,594,187	$ 1,686,067	$ 1,686,067	11
12	Ongoing CTC Cost RRQ ($1000)		$ 536,317	$ 536,317	$ 536,317	12
13	Ongoing CTC - EOY MTCBA Balance ($1000)		$ -	$ -	$ -	13
14	PCIA RRQ ($1000) = Line 11 - (Line 12 + Line 13)		$ 1,057,870	$ 1,149,750	$ 1,149,750	14
15	PCIA RRQ w/o Uncollectibles ($1000)		$ 1,055,139	$ 1,146,782	$ 1,146,782	15
16	**franchise fees and uncollectibles factor**	0.010255				16
17	**franchise fees factor**	0.007647				17

	2009 Vintage	2010 Vintage	2011 Vintage
Change in PCIA RRQ	(52,668)	(53,569)	(53,569)
New Simple Average PCIA ($/kWh)	0.01320	0.01463	0.01492
Change as a result of Adjusting BM Peak to match Total Portfolio	(0.00066)	(0.00068)	(0.00070)
Percent Change	-4.8%	-4.5%	-4.5%

November ERRA Update - Table 7-4 and 7-5

Line No.	Forecast Indifference Amount		D.04-12-048 PCIA			
	2011 Annual ERRA Forecast - November Update with AET CTC RRQ		**2009 Vintage**	**2010 Vintage**	**2011 Vintage**	
1	Total Portfolio Generation at generator (GWh)		72,013	72,960	72,960	1
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)		67,692	68,582	68,582	2
3	Total Portfolio Cost ($1000)		$4,517,148	$4,646,766	$4,646,766	3
4	Benchmark ($/MWh)	$42.42				4
5	Market Cost ($1000)		$2,871,217	$2,908,994	$2,908,994	5
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)		$1,645,932	$1,737,772	$1,737,772	6
7						7
8	**Indifference Results, current year (excludes ff&u) ($1000)**		$1,645,932	$1,737,772	$1,737,772	8
9	2010 Cummulative Indifference Amount		$ -	$ -	$ -	9
10	2011 Cumulative Indifference Amount (prior year(s) + current year results)		$ 1,645,932	$ 1,737,772	$ 1,737,772	10
11	2011 Cumulative Indifference Amount w/ ff&u		$ 1,662,811	$ 1,755,593	$ 1,755,593	11
12	Ongoing CTC Cost RRQ ($1000)		$ 552,136	$ 552,136	$ 552,136	12
13	Ongoing CTC - EOY MTCBA Balance ($1000)		$ -	$ -	$ -	13
14	PCIA RRQ ($1000) = Line 11 - (Line 12 + Line 13)		$ 1,110,675	$ 1,203,457	$ 1,203,457	14
15	PCIA RRQ w/o Uncollectibles ($1000)		$ 1,107,808	$ 1,200,350	$ 1,200,350	15
16	**franchise fees and uncollectibles factor**	0.010255				16
17	**franchise fees factor**	0.007647				17

Simple Average PCIA ($/kWh)	0.01386	0.01531	0.01561

Remove ISO Load Based Costs	$ 62,535.95	$ 63,358.89	$ 63,358.89

November ERRA Update - Table 7-4 and 7-5

Line No.	Forecast Indifference Amount		D.04-12-048 PCIA			
	2011 Annual ERRA Forecast - November Update with AET CTC RRQ		**2009 Vintage**	**2010 Vintage**	**2011 Vintage**	
1	Total Portfolio Generation at generator (GWh)		72,013	72,960	72,960	1
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)		67,692	68,582	68,582	2
3	Total Portfolio Cost ($1000) less ISO Load Related Costs		$4,454,612	$4,583,407	$4,583,407	3
4	Benchmark ($/MWh)	$42.42				4
5	Market Cost ($1000)		$2,871,217	$2,908,994	$2,908,994	5
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)		$1,583,396	$1,674,413	$1,674,413	6
7						7
8	**Indifference Results, current year (excludes ff&u) ($1000)**		$1,583,396	$1,674,413	$1,674,413	8
9	2010 Cummulative Indifference Amount		$ -	$ -	$ -	9
10	2011 Cumulative Indifference Amount (prior year(s) + current year results)		$ 1,583,396	$ 1,674,413	$ 1,674,413	10
11	2011 Cumulative Indifference Amount w/ ff&u		$ 1,599,633	$ 1,691,584	$ 1,691,584	11
12	Ongoing CTC Cost RRQ ($1000)		$ 552,136	$ 552,136	$ 552,136	12
13	Ongoing CTC - EOY MTCBA Balance ($1000)		$ -	$ -	$ -	13
14	PCIA RRQ ($1000) = Line 11 - (Line 12 + Line 13)		$ 1,047,498	$ 1,139,449	$ 1,139,449	14
15	PCIA RRQ w/o Uncollectibles ($1000)		$ 1,044,793	$ 1,136,507	$ 1,136,507	15
16	**franchise fees and uncollectibles factor**	0.010255				16
17	**franchise fees factor**	0.007647				17

Change in PCIA RRQ	(63,014)	(63,843)	(63,843)
New Simple Average PCIA ($/kWh)	0.01307	0.01450	0.01478
Change as a result of removing ISO Load Based Costs	(0.00079)	(0.00081)	(0.00083)
Percent Change	-5.7%	-5.3%	-5.3%

November ERRA Update - Table 7-4 and 7-5

Line No.	Forecast Indifference Amount 2011 Annual ERRA Forecast - November Update with AET CTC RRQ	D.06-07-030 PCIA			D.04-12-048 PCIA 2009 Vintage	 2010 Vintage	 2011 Vintage	
1	Total Portfolio Generation at generator (GWh)	50,961			72,013	72,960	72,960	1
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)	47,904			67,692	68,582	68,582	2
3	Total Portfolio Cost ($1000)	$2,257,872.634			$ 4,517,148.072	$ 4,646,765.947	$ 4,646,765.947	3
4	Benchmark ($/MWh) $42.42							4
5	Market Cost ($1000)	$2,031,885.114			$ 2,871,216.558	$ 2,908,993.861	$ 2,908,993.861	5
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)	$225,987.520			$ 1,645,931.514	$ 1,737,772.085	$ 1,737,772.085	6
7								7
8	**Indifference Results, current year (excludes ff&u) ($1000)**	$225,987.520			$ 1,645,931.514	$ 1,737,772.085	$ 1,737,772.085	8
		Pre-2009 NIAMA	**Post-2009 NIAMA**					
9	2010 Cummulative Indifference Amount	$ (732,328.954)	$ -		$ -	$ -	$ -	9
10	2011 Cumulative Indifference Amount (prior year(s) + current year results)	$ (506,341.434)	$ 225,987.520		$ 1,645,931.514	$ 1,737,772.085	$ 1,737,772.085	10
11	2011 Cumulative Indifference Amount w/ ff&u	$ -	$ 228,305.022		$ 1,662,810.541	$ 1,755,592.938	$ 1,755,592.938	11
12	Ongoing CTC Cost RRQ ($1000)	$ 552,135.763	$ 552,135.763		$ 552,135.763	$ 552,135.763	$ 552,135.763	12
13	Ongoing CTC - EOY MTCBA Balance ($1000)	$ 81,421.835	$ -		$ -	$ -	$ -	13
14	PCIA RRQ ($1000) = Line 11 - (Line 12 + Line 13)	$ (633,557.598)	$ (323,830.740)		$ 1,110,674.779	$ 1,203,457.175	$ 1,203,457.175	14
15	PCIA RRQ w/o Uncollectibles ($1000)				$ 1,107,807.543	$ 1,200,350.419	$ 1,200,350.419	15
16	**franchise fees and uncollectibles factor** 0.010255							16
17	**franchise fees factor** 0.007647							17
18	**LOAD FORECAST FOR NIAMA ALLOCATION**	**D.06-07-030 PCIA**			**D.04-12-048 PCIA**			18
19	**D.04-12-048 Non-Exempt Departing Customers**	**Pre-2009**	**Post-2009**		**2009**	**2010**	**2011**	19
20	CCA	N/A	N/A		135.81	28.62	-	20
21	Direct Access - Reopening	N/A	N/A		-	1,500.00	1,500.00	21
22	Split Wheeling	6.5	N/A		-	-	-	22
23	Large Municipal	-	N/A		-	-	-	23
24	**Total Non-Exempt Departures, by vintage**	***6.5***			***135.8***	***1,528.6***	***1,500.0***	24
25								25
26	**D.06-07-030 Non-Exempt Departing Customers**							26
27	NMDL - Non-Exempt – D.06-07-030 Indifference $_{DWR}$	**-**	**-**		N/A	N/A	N/A	27
28	DA non-continuous - D.06-07-030 Indifference $_{DWR}$	*5,447*	N/A		N/A	N/A	N/A	28
29	Bundled	76,880	76,880		76,880	76,880	76,880	29
30								30
31	**Sales Total (GWh) = load responsible for portfolio**	**82,334**	**76,880**		**76,880**	**76,880**	**76,880**	31
32	**Sales Total Cumulative (GWh)**	**85,498**	**80,045**		**79,909**	**78,380**	**76,880**	32

SB_GT&S_0015093

PG&E Market Price Benchmark for 2010 & 2011

Line #	Forecast Year	2010	2011	2011	2011
		Oct 2009 Data	April 2010 Data	April 2010 Data	April 2010 Data
	Forward Price Location	NP15	NP15	NP15	NP15
	Average Prices from October Postings	PG&E	PG&E	PG&E	PG&E
1	On Peak				
2	Off Peak				
3	Publication	Platts ICE	Platts ICE	Platts ICE	Platts ICE
4		thru 10/30/09	thru 04/30/2010	thru 04/30/2010	thru 04/30/2010
5					
6	Sundays: number of days	52	52		52
7	Non-Sundays: number of days	313	313		313
8	Off-peak hours M-Sat	8	8	34.16%	8
9	On-peak hours M-Sat	16	16	65.84%	16
10	Hours per Year	8760	8760		8760
11	Calculated Baseload Price	$53.46	$36.02	$36.96	$36.02
12					
13					
14	Capacity Adder	$ 4.00	$ 4.00	$ 4.00	$ 7.69
15					
16	Subtotol Before Line Loss	$57.46	$40.02	$40.96	$43.71
17					
18	Line Loss	1.060	1.060	1.060	1.060
19					
20	**Market Price Benchmark**	**$60.91** [2]	**$42.42** [3]	**$43.42**	**$46.33**
				Change: $1.00	Change: $3.91

Fn 1: Using Calendar 2010 forward prices from all the trading days in October 2009

Fn 2: Using Calendar 2011 forward prices from all the trading days in April 2010

Fn 3: Using Calendar 2011 forward prices from all the trading days in October 2010

TABLE 7-2
PACIFIC GAS AND ELECTRIC COMPANY
2011 ONGOING CTC FORECAST REVENUE REQUIREMENT
NOVEMBER 5, 2010 UPDATE

Line No.	Description	$/MWh	GWh	$000	
1	Qualifying Facilities (Ongoing CTC Eligible)				From Table 5-2 Line 5 & 6
2	Gas Hedging for QF SRAC payments				Calculated from Table 6-2 (Cell B6)
3	Metropolitan Water District				From Table 5-2 Line 12 & 13
4	Irrigation Districts and Water Agencies				From Table 5-2 Line 9 & 10
5	Total (Lines 1 - 4)		16,600	1,187,690	
6	6% Line Loss		(996)		D.07-01-030
7	Net Pre-1996 Contracts (Lines 6 - 7)		15,604	1,187,690	
8	Market Benchmark Cost	$42.42	15,604	661,858	Benchmark rate of $42.42 is calculated based on October 2010 NP 15 Forward
9	Above Market Costs (Lines 7 Minus line 8)			525,831	
10	QF Restructuring Costs			20,700	From Table 5-2 Line 7
11	Subtotal Ongoing CTC Costs			546,531	
12	FFU			5,605	
13	Subtotal, Ongoing CTC Cost With FF&U			552,136	
14	Year-end 2010 MTCBA Balance			81,422	Based on actuals @ Sept 2010 + Forecast from Oct to Dec 2010
15	Total 2011 Ongoing CTC Revenue Requirement			633,558	

TABLE 7-2
PACIFIC GAS AND ELECTRIC COMPANY
2011 ONGOING CTC FORECAST REVENUE REQUIREMENT

Adjust Benchmark for portfolio peak generation $43.42

Line No.	Description	$/MWh	GWh	$000	
1	Qualifying Facilities (Ongoing CTC Eligible)				From Table 5-2 Line 5 & 6
2	Gas Hedging for QF SRAC payments				Calculated from Table 6-2 (Cell B6)
3	Metropolitan Water District				From Table 5-2 Line 12 & 13
4	Irrigation Districts and Water Agencies				From Table 5-2 Line 9 & 10
5	Total (Lines 1 - 4)		16,600	1,187,690	
6	6% Line Loss		(996)		D.07-01-030
7	Net Pre-1996 Contracts (Lines 6 - 7)		15,604	1,187,690	
8	Market Benchmark Cost		15,604	677,517	Revised Benchmark rate shown in red is adjusted for peak / off-peak generation profile; this generates new mkt portfolio cost
9	Above Market Costs (Lines 7 Minus line 8)			510,173	
10	QF Restructuring Costs			20,700	From Table 5-2 Line 7
11	Subtotal Ongoing CTC Costs			530,873	
12	FFU			5,444	
13	Subtotal, Ongoing CTC Cost With FF&U			536,317	
14	Year-end 2010 MTCBA Balance			81,422	Based on actuals @ Sept 2010 + Forecast from Oct to Dec 2010
15	Total 2011 Ongoing CTC Revenue Requirement			617,739	

TABLE 7-2
PACIFIC GAS AND ELECTRIC COMPANY
2011 ONGOING CTC FORECAST REVENUE REQUIREMENT

Adjust Benchmark for Capacity cost $ 46.33

Line No.	Description	$/MWh	GWh	$000	
1	Qualifying Facilities (Ongoing CTC Eligible)				From Table 5-2 Line 5 & 6
2	Gas Hedging for QF SRAC payments				Calculated from Table 6-2 (Cell B6)
3	Metropolitan Water District				From Table 5-2 Line 12 & 13
4	Irrigation Districts and Water Agencies				From Table 5-2 Line 9 & 10
5	Total (Lines 1 - 4)		16,600	1,187,690	
6	6% Line Loss		(996)		D.07-01-030
7	Net Pre-1996 Contracts (Lines 6 - 7)		15,604	1,187,690	
8	Market Benchmark Cost		15,604	722,915	Revised Benchmark rate shown in red is adjusted for peak / off-peak generation profile; this generates new mkt portfolio cost
9	Above Market Costs (Lines 7 Minus line 8)			464,775	
10	QF Restructuring Costs			20,700	From Table 5-2 Line 7
11	Subtotal Ongoing CTC Costs			485,475	
12	FFU			4,979	
13	Subtotal, Ongoing CTC Cost With FF&U			490,453	
14	Year-end 2010 MTCBA Balance			81,422	Based on actuals @ Sept 2010 + Forecast from Oct to Dec 2010
15	Total 2011 Ongoing CTC Revenue Requirement			571,875	

TABLE 7-2
PACIFIC GAS AND ELECTRIC COMPANY
2011 ONGOING CTC FORECAST REVENUE REQUIREMENT

Adjust Benchmark for renewable cost ($/MWh adjustment) = RPS Premium * RPS % in Portfolio $43.52

Line No.	Description	$/MWh	GWh	$000	
1	Qualifying Facilities (Ongoing CTC Eligible)				From Table 5-2 Line 5 & 6
2	Gas Hedging for QF SRAC payments				Calculated from Table 6-2 (Cell B6)
3	Metropolitan Water District				From Table 5-2 Line 12 & 13
4	Irrigation Districts and Water Agencies				From Table 5-2 Line 9 & 10
5	Total (Lines 1 - 4)		16,600	1,187,690	
6	6% Line Loss		(996)		D.07-01-030
7	Net Pre-1996 Contracts (Lines 6 - 7)		15,604	1,187,690	
8	Market Benchmark Cost		15,604	679,151	Revised Benchmark rate shown in red is adjusted for peak / off-peak generation profile; this generates new mkt portfolio cost
9	Above Market Costs (Lines 7 Minus line 8)			508,538	
10	QF Restructuring Costs			20,700	From Table 5-2 Line 7
11	Subtotal Ongoing CTC Costs			529,238	
12	FFU			5,427	
13	Subtotal, Ongoing CTC Cost With FF&U			534,666	
14	Year-end 2010 MTCBA Balance			81,422	Based on actuals @ Sept 2010 + Forecast from Oct to Dec 2010
15	Total 2011 Ongoing CTC Revenue Requirement			616,087	

TABLE 7-2
PACIFIC GAS AND ELECTRIC COMPANY
2011 ONGOING CTC FORECAST REVENUE REQUIREMENT

Cumulative Adjusted Benchmark $48.44

Line No.	Description	$/MWh	GWh	$000	
1	Qualifying Facilities (Ongoing CTC Eligible)				From Table 5-2 Line 5 & 6
2	Gas Hedging for QF SRAC payments				Calculated from Table 6-2 (Cell B6)
3	Metropolitan Water District				From Table 5-2 Line 12 & 13
4	Irrigation Districts and Water Agencies				From Table 5-2 Line 9 & 10
5	Total (Lines 1 - 4)		16,600	1,187,690	
6	6% Line Loss		(996)		D.07-01-030
7	Net Pre-1996 Contracts (Lines 6 - 7)		15,604	1,187,690	
8	Market Benchmark Cost		15,604	755,866	Revised Benchmark rate shown in red is adjusted for peak / off-peak generation profile; this generates new mkt portfolio cost
9	Above Market Costs (Lines 7 Minus line 8)			431,824	
10	QF Restructuring Costs			20,700	From Table 5-2 Line 7
11	Subtotal Ongoing CTC Costs			452,524	
12	FFU			4,641	
13	Subtotal, Ongoing CTC Cost With FF&U			457,164	
14	Year-end 2010 MTCBA Balance			81,422	Based on actuals @ Sept 2010 + Forecast from Oct to Dec 2010
15	Total 2011 Ongoing CTC Revenue Requirement			538,586	

PACIFIC GAS AND ELECTRIC COMPANY
Direct Access Reopening OIR
Rulemaking 07-05-025
Data Response

PG&E Data Request No.:	ED_001-03		
PG&E File Name:	DirectAccessReopeningOIR_DR_ED_001-Q03		
Request Date:	December 14, 2010	Requester DR No.:	ED_DR001
Date Sent:	December 22, 2010	Requesting Party:	Steve Roscow
PG&E Witness:	Bill Chen	Requester:	Energy Division on behalf of Joint Parties

QUESTION 3

Provide / describe continuous-DA issue – prevalence

ANSWER 3

PG&E has 4,669 active accounts that are categorized as "Continuous DA." Of these, 2,529 have been DA as of February 1, 2001 or earlier, and have never returned to bundled service. Thus, there are 2,140 active accounts that are grandfathered as "Continuous DA" but they are currently receiving bundled service or have recently returned to DA service after being bundled service customers. The accounts are shown in the table below:

Continuous DA	Total	Continuous DA DA Accounts	Continuous DA Bundled Accounts
Total	4,669	2,529	2,1430
Residential	4,537	2,444	2,093
Commercial / Industrial	125	82	43
Agricultural	7	3	4

PACIFIC GAS AND ELECTRIC COMPANY
Direct Access Reopening OIR
Rulemaking 07-05-025
Data Response

PG&E Data Request No.:	ED_001-04		
PG&E File Name:	DirectAccessReopeningOIR_DR_ED_001-Q04		
Request Date:	December 14, 2010	Requester DR No.:	ED_DR001
Date Sent:	December 16, 2010	Requesting Party:	Steve Roscow
PG&E Witness:	Marc Renson	Requester:	Energy Division on behalf of Joint Parties

QUESTION 4

Provide TBS scalars linked to MPB adjustment.

ANSWER 4

The TBS scalar for renewables is 1.09 and is calculated in cell G64 of tab "2.b RPS Adder to BM" in the spreadsheet attachment to question 2.

The TBS scalar for capacity is 1.29 and is calculated in cell G58 of tab "2.a BM Capacity Adder Update" in the spreadsheet attachment to question 2.

PACIFIC GAS AND ELECTRIC COMPANY
Direct Access Reopening OIR
Rulemaking 07-05-025
Data Response

PG&E Data Request No.:	ED_001-05		
PG&E File Name:	DirectAccessReopeningOIR_DR_ED_001-Q05		
Request Date:	December 14, 2010	Requester DR No.:	ED_DR001
Date Sent:	December 16, 2010	Requesting Party:	Steve Roscow
PG&E Witness:	Donna Barry	Requester:	Energy Division on behalf of Joint Parties

QUESTION 5

Provide 2011 Update to Victorville DR.

ANSWER 5

In a December 7, 2010 email from Scott Blasing, sent to the service list in this proceeding, the circumstances surrounding the previous data request (DR) was described as follows:

> "During today's workshop, I mentioned that in response to the City of Victorville's previous petition for modification SCE provided information (in the aggregate) as to what the indifference rate would be if all RPS resources (and also, separately, all "new world" RPS resources) were removed from the indifference rate calculation. I've attached the joint utilities' reply, which contains SCE's previously provided information (at pages 12-14). Specifically, with respect to SCE, the following factual assertion was made (at page 13):
>
> *Indeed, removing all renewable resources from the total portfolio would lower the 2008 vintage CRS by only 0.2 cents per kWh. Moreover, removing only those renewable costs which are 2004 vintage or later would only lower the 2008 vintage CRS by 0.07 cents per kWh.*
>
> It would be very helpful if the utilities could update these statements with respect to the 2011 vintage.
>
> Thank you.
>
> Scott Blaising, for CMUA and SJVPA
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SB_GT&S_0015098

As discussed at the workshop on December 14, 2010, for PG&E, the information requested by CMUA is confidential and as such, cannot be provided to market participants. PG&E will provide this analysis Energy Division under the confidentiality declaration.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of this ***Workshop Report of the Joint Parties*** on all parties of record in proceeding ***R.07-05-025*** by serving an electronic copy on their email addresses of record and by mailing a properly addressed copy by first-class mail with postage prepaid to each party for whom an email address is not available.

Executed on January 14, 2011, at Woodland Hills, California.

Michelle Dangott

Michelle Dangott

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