State of California

Department of Water Resources

Supplemental Determination of Revenue Requirements

For the Period

January 1, 2008 through December 31, 2008

Submitted To
The California Public Utilities Commission
Pursuant To
Sections 80110 and 80134 of the California Water Code

February 15, 2008

Table of Contents

A. THE SUPPLEMENTAL DETERMINATION 1
GENERAL 1
DETERMINATION OF REVENUE REQUIREMENTS 2
FUTURE ADJUSTMENT OF REVENUE REQUIREMENTS 5
B. BACKGROUND 5
THE ACT AND THE RATE AGREEMENT 5
PRIOR PROCEEDINGS RELATING TO 2008 5
THE SUPPLEMENTAL 2008 DETERMINATION 6
C. THE DEPARTMENT'S SUPPLEMENTAL DETERMINATION OF REVENUE REQUIREMENTS FOR THE PERIOD JANUARY 1, 2008 THROUGH DECEMBER 31, 2008 9
REVENUE REQUIREMENT DETERMINATION 9
D. ASSUMPTIONS GOVERNING THE DEPARTMENT'S PROJECTION OF REVENUE REQUIREMENTS FOR THE 2008 REVENUE REQUIREMENT PERIOD 11
ESTIMATED ENERGY REQUIREMENTS 11
DIRECT ACCESS 11
COMMUNITY CHOICE AGGREGATION 12
POWER SUPPLY RELATED ASSUMPTIONS 13
UTILITY RESOURCES 14
HYDRO CONDITION ASSUMPTIONS 14
CONTRACT ASSUMPTIONS 14
CONTRACT MANAGEMENT AND DISPOSITION ALTERNATIVES 18
COST RESPONSIBILITY SURCHARGE 18
SALES OF EXCESS ENERGY ASSUMPTIONS 19
LONG-TERM POWER CONTRACT COST ASSUMPTIONS 20
NATURAL GAS PRICE FORECAST AND FUELS ASSUMPTIONS 20
GAS HEDGING EXPENSE 22
CALIFORNIA INDEPENDENT SYSTEM OPERATOR MARKET REDESIGN AND TECHNOLOGY UPGRADE ASSUMPTIONS 22
ADMINISTRATIVE AND GENERAL COSTS 23
FINANCING RELATED ASSUMPTIONS 23
ACCOUNTS AND FLOW OF FUNDS UNDER THE BOND INDENTURE 23
OPERATING ACCOUNT 24
OPERATING RESERVE ACCOUNT 24
DEBT SERVICE RESERVE ACCOUNT 25
SENSITIVITY ANALYSIS 25
CASE 1 26
CASE 2 28
E. POWER CONTRACT SETTLEMENT SUMMARY 29
F. KEY UNCERTAINTIES IN THE REVENUE REQUIREMENT DETERMINATION 30
G. JUST AND REASONABLE DETERMINATION 32
PRIOR DETERMINATIONS 32
THE SUPPLEMENTAL 2008 DETERMINATION 32
PUBLIC PROCESS 32
JUST AND REASONABLE DETERMINATION 32
H. MARKET SIMULATION 34
I. COMMENTS RECEIVED ON THE SUPPLEMENTAL 2008 DETERMINATION AND THE DEPARTMENT'S RESPONSES 34
J. ANNOTATED REFERENCE INDEX OF MATERIALS UPON WHICH THE DEPARTMENT RELIED TO MAKE THE DETERMINATION 41
ATTACHMENT A 46

List of Tables

TABLE A-1 SUMMARY OF THE DEPARTMENT'S 2008 POWER CHARGE REVENUE REQUIREMENTS AND POWER CHARGE ACCOUNTS AND COMPARISON TO 2007[1] 3
TABLE A-2 SUMMARY OF THE DEPARTMENT'S 2008 BOND CHARGE REVENUE REQUIREMENTS AND BOND CHARGE ACCOUNTS AND COMPARISON TO 2007[1]. 4
TABLE B-1 SUMMARY OF THE DEPARTMENT'S 2008 POWER CHARGE REVENUE REQUIREMENTS AND POWER CHARGE ACCOUNTS AND COMPARISON TO OCTOBER 31, 2007 DETERMINATION 8
TABLE C-1 POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE: RETAIL CUSTOMER POWER CHARGE CASH REQUIREMENT 9
TABLE C-2 POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE: RETAIL CUSTOMER BOND CHARGE CASH REQUIREMENT 10
TABLE D-1 ESTIMATED ANNUAL ENERGY REQUIREMENTS 11
TABLE D-2 2008 DIRECT ACCESS FORECAST 12
TABLE D-3 ESTIMATED NET SHORT ENERGY, SUPPLY FROM THE DEPARTMENT'S LONG-TERM POWER CONTRACTS AND THE DEPARTMENT'S ESTIMATE OF THE RESIDUAL NET SHORT 13
TABLE D-4 NET SHORT, SUPPLY FROM THE DEPARTMENT'S LONG-TERM POWER CONTRACTS, OFF-SYSTEM SALES AND RESIDUAL NET SHORT IN 2008[1] 14
TABLE D-5 LONG-TERM POWER CONTRACT LISTING 16
TABLE D-6 PROJECTED SALE OF EXCESS ENERGY[1] 19
TABLE D-7 ESTIMATED POWER SUPPLY COSTS 20
TABLE D-8 NATURAL GAS PRICE FORECAST COMPARISON AT HENRY HUB 21
TABLE D-9 NATURAL GAS AVERAGE PRICE FORECASTS 21
TABLE D-10 STRESS CASE – NATURAL GAS PRICE FORECASTS 27

A. THE SUPPLEMENTAL DETERMINATION

GENERAL

Pursuant to Section 80110 of the California Water Code, the Rate Agreement between the State of California Department of Water Resources (the "Department" or "DWR") and the California Public Utilities Commission (the "Commission" or "CPUC"), dated March 8, 2002 (the "Rate Agreement"), and Division 23, Chapter 4, Sections 510–517 of the California Code of Regulations ("the Regulations"), the Department hereby issues its Proposed Supplemental Determination of Revenue Requirements for the period January 1, 2008 through December 31, 2008 (the " Supplemental 2008 Determination"). Capitalized terms used and not otherwise defined herein have the meanings given to such terms in the Rate Agreement or the Indenture under which the Department's Power Supply Revenue Bonds were issued (the "Bond Indenture").

The costs of the Department's purchases to meet the net short requirements of retail end use customers in the three California investor-owned utilities (the "Utilities" or "IOUs") namely, Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE") and San Diego Gas & Electric Company ("SDG&E") service territories, including the costs of administering the long-term contracts, are to be recovered from payments made by customers and collected by the IOUs on behalf of the Department. The terms and conditions for the recovery of the Department's costs from customers are set forth in the Act, the Regulations, the Rate Agreement and orders of the Commission. Among other things, the Rate Agreement contemplates a "Bond Charge" (as that term is defined in the Rate Agreement) that is designed to recover the Department's costs associated with its bond financing activity ("Bond Related Costs") and a "Power Charge" (as that term is defined in the Rate Agreement) that is designed to recover "Department Costs", or the Department's "Retail Revenue Requirements" (as those terms are defined in the Rate Agreement), including power supply-related costs. Subject to the conditions described in the Rate Agreement and other Commission Decisions, Bond Charges and certain charges designed to recover Department Costs may also be imposed on the customers of Electric Service Providers (as that term is defined in the Rate Agreement).[1] Additional background material is contained in the Department's prior Determinations of Revenue Requirements, copies of which have been incorporated into the administrative record supporting this Determination.

Pursuant to Sections 80110 and 80134 of the California Water Code and the Rate Agreement, this Supplemental 2008 Determination contains information on the amounts required to be recovered, on a cash basis, in the 2008 Revenue Requirement Period (calendar year 2008).

After submitting the 2008 Revised Revenue Requirement Determination to the CPUC on October 31, 2007, the Department entered into a modification of a long-term power contract with Calpine Energy Services, L.P formerly referred to as the "Long-Term Commodity Sale" contract ("Calpine 2"). The renegotiated contract was executed and delivered on December 7, 2007 and, effective January 1, 2008, replaces 1000 megawatts of 7x24 energy deliveries through 2009 with

[1] Under the Rate Agreement, the "Retail Revenue Requirement" is the amount to be recovered from "Power Charges" on IOU customers. The assessment on customers of Electric Service Providers of charges to recover Department Costs (e.g., "Direct Access Power Charge Revenues") reduces the amount of the "Retail Revenue Requirement," but has no material impact on the Department's costs.

180 megawatts of unit-contingent dispatchable capacity during 2008 and 2009. Additionally, the Department has an option to extend the contract through 2012. Detailed contract terms can be found on the CERS website, http://www.cers.water.ca.gov.

This Supplemental 2008 Determination incorporates the restructured contract. Additionally, preliminary operating results through December 31, 2007 have recently been compiled and are incorporated in this Supplemental 2008 Revenue Requirement All other underlying assumptions remain unchanged from the October 31, 2007 Revised 2008 Revenue Requirement allocated by the CPUC on December 20, 2007.

For the 2008 Revenue Requirement Period, this Supplemental 2008 Determination contains information regarding the following[2]: (a) the beginning balance of funds on deposit in the Electric Power Fund (the "Fund"), including the amounts on deposit in each account and sub-account of the Fund; (b) the amounts projected to be necessary to pay the principal, premium, if any, and interest on all bonds as well as all other Bond Related Costs as and when the same are projected to become due, and the projected amount of Bond Charges required to be collected for such purpose; and (c) the amount needed to pay the Department's costs, including all Retail Revenue Requirements.

DETERMINATION OF REVENUE REQUIREMENTS

Pursuant to the Act, the Rate Agreement and the Regulations, the Department determines, on the basis of the materials presented and referred to by this Supplemental 2008 Determination (including the materials referenced in Section J), that its cash basis revenue requirement for 2008 is $3.992 billion, consisting of $3.162 billion in Power Charges and $0.831 billion in Bond Charges.

Table A-1 shows a summary of the Department's revenue requirements and the accounts associated with projected Department Costs ("Power Charge Accounts") for 2008. These figures are compared to those reflected in the Department's 2007 Determination. Table B-1 shows a comparison to those reflected in the Department's October 31, 2007 Revised Determination for 2008.

A summary and comparison of the Department's revenue requirements and the accounts associated with its Bond Related Costs ("Bond Charge Accounts") is presented in Table A-2. Definitions of key accounts and sub-accounts are presented within each table.

[2] Where appropriate, the Department has provided information in this 2008 Supplemental Determination on a quarterly basis. In other instances, particularly where information might be considered market-sensitive, the Department has provided information on an annual basis. Within this 2008 Supplemental Determination, quantitative statistics presented in tabular form may not add due to rounding.

TABLE A-1
SUMMARY OF THE DEPARTMENT'S 2008 POWER CHARGE REVENUE REQUIREMENTS AND POWER CHARGE ACCOUNTS AND COMPARISON TO 2007[1]
($ Millions)

Line	Description	2008[2]	2007[3]	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	1,109	1,063	46
3	Priority Contract Account	115	-	115
4	Operating Reserve Account	612	591	21
5	**Total Beginning Balance in Power Charge Accounts**	**1,836**	**1,653**	**182**
6	*Power Charge Accounts Operating Revenues*			-
7	Power Charge Revenues[4]	3,162	4,191	(1,030)
8	Other Revenue[5]	60	190	(130)
9	Interest Earnings on Fund Balances	86	80	6
10	**Total Power Charge Accounts Operating Revenues**	**3,308**	**4,461**	**(1,153)**
11	*Power Charge Accounts Operating Expenses*			-
12	Administrative and General Expenses	28	26	2
13	Total Power Costs[6]	3,690	4,540	(850)
14	**Total Power Charge Accounts Operating Expenses**	**3,718**	**4,566**	**(848)**
15	Net Operating Revenues	(410)	(105)	(305)
16	**Ending Aggregate Balance in Power Charge Accounts**	**1,426**	**1,549**	**(123)**

Target Minimum Power Charge Account Balances	Target (Millions of Dollars)		
Operating Account: This minimum balance is targeted to cover intra-month volatility as measured by the maximum difference in revenues and expenses in a calendar month.	337	318	19
Operating Reserve Account: Covers deficiencies in the Operating Account. It is sized as the greater of (i) the maximum seven-month difference between operating revenues and expenses as calculated under a stress scenario, (ii) 12% of the Department's annual operating expenses and (iii) an amount equal to the maximum projected monthly contract cost payment.	548	612	(64)
Total Operating Reserves:	885	930	(45)

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the 2007 Final Determination.
[4]Includes Bundled customer revenues and Cost Responsibility Surcharge revenues, whether from Direct Access or other sources, such as Community Choice Aggregation.
[5]Other revenues received by the Department are those related to surplus energy sales conducted by the IOUs when the IOUs and the Department have procured more energy than is needed to serve retail customers; details related to surplus energy sales are further discussed in Section D.
[6]Includes gas hedging and collateral amounts.

TABLE A-2
SUMMARY OF THE DEPARTMENT'S 2008 BOND CHARGE REVENUE REQUIREMENTS AND BOND CHARGE ACCOUNTS AND COMPARISON TO 2007[1]
($ Millions)

Line	Description	2008[2]	2007[3]	Difference
1	*Beginning Balance in Bond Charge Accounts*			
2	Bond Charge Collection Account	210	184	25
3	Bond Charge Payment Account	607	591	16
4	Debt Service Reserve Account	930	913	18
5	**Total Beginning Balance in Bond Charge Accounts**	**1,748**	**1,688**	**59**
6	*Bond Charge Accounts Revenues*			
7	Bond Charge Revenues from Utiltities[4]	831	818	13
8	Interest Earnings on Fund Balances	83	79	4
9	**Total Bond Charge Accounts Revenues**	**914**	**897**	**17**
10	*Bond Charge Accounts Expenses*			
11	Debt Service on Bonds[5]	935	920	15
12	**Total Bond Charge Accounts Expenses**	**935**	**920**	**15**
13	Net Bond Charge Revenues	(21)	(23)	2
14	**Ending Aggregate Balance in Bond Charge Accounts**	**1,726**	**1,665**	**61**

Target Minimum Bond Charge Account Balances	Target (Millions of Dollars)		
Bond Charge Collection Account: An amount equal to one month's required deposit to the Bond Charge Payment Account for projected debt service	78 - 80	76 - 78	
Bond Charge Payment Account: An amount equal to the debt service accrued and unpaid through the end of the third next succeeding calendar month	324 - 825	318 - 810	
Debt Service Reserve Account: Established as the maximum annual debt service	937	930	7

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the 2007 Final Determination.
[4]Cost Responsibility Surcharge revenues are included in this amount, whether from Direct Access or other sources, such as Community Choice Aggregation.
[5]Debt service on bonds includes net qualified swap payments.

FUTURE ADJUSTMENT OF REVENUE REQUIREMENTS

The Department may again propose to revise its revenue requirements for the 2008 Revenue Requirement Period given the potential for significant or material changes in the California energy market, the status of market participants, decisions made in connection with the California Independent System Operator's Market Redesign and Technology Upgrade ("MRTU") proceeding, the Department's associated obligations and operations, and many other events that may materially affect the realized or projected financial performance of the Power Charge Accounts or the Bond Charge Accounts. In such event, the Department will inform the Commission of such material changes and will revise its revenue requirements accordingly. Several relevant factors are discussed in more detail within Section D.

B. BACKGROUND

THE ACT AND THE RATE AGREEMENT

Information on the Act and the Rate Agreement, which have not changed since 2002, is contained in the Department's prior Determinations of Revenue Requirements, copies of which have been incorporated into the administrative record supporting this Determination.

PRIOR PROCEEDINGS RELATING TO 2008

Information obtained from the IOUs in April 2007 served as the basis for the Department's analytical and forecasting efforts related to the original 2008 Proposed Determination. The resulting data was incorporated into the PROMOD IV market simulation model, and became a part of the projections leading to the 2008 Proposed Determination.

On July 20, 2007, the Department issued its Proposed Determination of Revenue Requirements for 2008 (the "Proposed Determination"), consistent with the requirements of Sections 80110 and 80134 of the California Water Code, and provided information consistent with the Regulations. The Department provided interested persons with quantitative results from its PROMOD market simulation and Financial Model, subject to applicable non-disclosure requirements. Interested persons were advised to submit comments no later than August 10, 2007. The comments are summarized and the Department's responses are included in Section I of the 2008 Determination dated August 22, 2007.

On August 22, 2007 the Department published its Determination of Revenue Requirements for the period of January 1, 2008 through and including December 31, 2008 and submitted it to the Commission. The August 22, 2007 Determination was found to be just and reasonable based on an assessment of all comments, the administrative record, the Act, the Regulations, Bond Indenture requirements and the Rate Agreement.

The Department reviewed certain matters relating to its August 22, 2007 Determination, including, but not limited to, operating results of the Electric Power Fund (the "Fund") as of September 30, 2007 (the August 22, 2007 Determination incorporated preliminary actual operating results through June 2007); and an updated gas price forecast.

On October 10, 2007, the Department issued its Proposed Revised Determination of Revenue Requirements for 2008 (the "Proposed Revised Determination"), consistent with the requirements of Sections 80110 and 80134 of the California Water Code, and provided information consistent with the Regulations. The Department provided interested persons with quantitative results from its PROMOD market simulation and Financial Model, subject to applicable non-disclosure requirements. Interested persons were advised to submit comments no later than October 24, 2007. The comments are summarized and the Department's responses are included in Section I of the 2008 Revised Determination.

On October 31, 2007 the Department published its Revised Determination of Revenue Requirements for the period of January 1, 2008 through and including December 31, 2008 and submitted it to the Commission. The Revised Determination was found to be just and reasonable based on an assessment of all comments, the administrative record, the Act, the Regulations, Bond Indenture requirements and the Rate Agreement.

On December 20, 2007, the Commission issued Decision 07-12-030: "Order Allocating the 2008 Revenue Requirement Determination of the California Department of Water Resources".

THE SUPPLEMENTAL 2008 DETERMINATION

The Department reviewed certain matters relating to its October 31, 2007 Determination, including, but not limited to, the amended and restructured Calpine 2 Contract. On December 27, 2007, the Department issued its Proposed Supplemental Determination of Revenue Requirements for 2008 (the "Proposed Supplemental Determination"), consistent with the requirements of Sections 80110 and 80134 of the California Water Code, and provided information consistent with the Regulations. The Department provided interested persons with quantitative results from its PROMOD market simulation, the amended and restated Calpine 2 Contract and Financial Model, subject to applicable non-disclosure requirements. Interested persons were advised to submit comments no later than January 17, 2008.

Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company submitted comments. The comments were considered by the Department prior to this Supplemental 2008 Determination. The comments are summarized and the Department's responses are included in Section I.

The Department hereby supplements its October 31, 2007 Determination under Section 516 of the Regulations to address the following matters:

- The amended and restated Calpine 2 Contract; and
- Updated actual Electric Power Fund operating results through December 31, 2007

The revisions result in a total decrease in cost of $630 million in this Supplemental 2008 Determination compared to the October 31, 2007 Determination. The $630 million decrease results from the net effect of a decrease in contract costs due to the restructured Calpine 2 contract, an updated beginning of the year account balances which are higher than that projected in the Proposed Supplemental Determination and from a $74 million reduction in the year-end Power Charge Account balances as reported in Line 15 of Table B-1.

The Department's Bond Charge Revenue Requirement remains $831 million.

Table B-1 summarizes the changes between the Revised 2008 Determination published October 31, 2007, and this Supplemental 2008 Determination for the Power Charge revenue requirement and Power Charge Accounts.

TABLE B-1
SUMMARY OF THE DEPARTMENT'S 2008 POWER CHARGE REVENUE REQUIREMENTS AND POWER CHARGE ACCOUNTS AND COMPARISON TO OCTOBER 31, 2007 DETERMINATION
($ Millions) [1]

Line	Description	2008[2]	October 31, 2007 Determination	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	1,109	1,135	(26)
3	Priority Contract Account	115	-	115
4	Operating Reserve Account	612	612	0
5	**Total Beginning Balance in Power Charge Accounts**	**1,836**	**1,747**	**89**
6	*Power Charge Accounts Operating Revenues*			-
7	Power Charge Revenues[3]	3,162	3,792	(630)
8	Other Revenue[4]	60	60	(1)
9	Interest Earnings on Fund Balances	86	85	1
10	**Total Power Charge Accounts Operating Revenues**	**3,308**	**3,937**	**(629)**
11	*Power Charge Accounts Operating Expenses*			-
12	Administrative and General Expenses	28	28	-
13	Total Power Costs[5]	3,690	4,157	(467)
14	**Total Power Charge Accounts Operating Expenses**	**3,718**	**4,185**	**(467)**
15	Net Operating Revenues	(410)	(248)	(162)
16	**Ending Aggregate Balance in Power Charge Accounts**	**1,426**	**1,499**	**(74)**

Target Minimum Power Charge Account Balances	Target (Millions of Dollars)		
Operating Account: This minimum balance is targeted to cover intra-month volatility as measured by the maximum difference in revenues and expenses in a calendar month.	337	326	11
Operating Reserve Account: Covers deficiencies in the Operating Account. It is sized as the greater of (i) the maximum seven-month difference between operating revenues and expenses as calculated under a stress scenario, (ii) 12% of the Department's annual operating expenses and (iii) an amount equal to the maximum projected monthly contract cost payments.	548	548	-
Total Operating Reserves:	885	874	11

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]Includes Bundled customer revenues and Cost Responsibility Surcharge revenues, whether from Direct Access or other sources, such as Community Choice Aggregation.
[4]Other revenues received by the Department are those related to surplus energy sales conducted by the IOUs when the IOUs and the Department have procured more energy than is needed to serve retail customers; details related to surplus energy sales are further discussed in Section D.
[5]Includes gas hedging and collateral amounts.

C. THE DEPARTMENT'S SUPPLEMENTAL DETERMINATION OF REVENUE REQUIREMENTS FOR THE PERIOD JANUARY 1, 2008 THROUGH DECEMBER 31, 2008

REVENUE REQUIREMENT DETERMINATION

For 2008, the Department's revenue requirements consist of Department Costs and Bond Related Costs, which are to be satisfied primarily by Power Charge Revenues and Bond Charge Revenues, respectively.

During 2008, the Department projects that it will incur the following power procurement-related Costs: (a) $3.690 billion for long-term power contract purchases to cover the net short requirement of customers; (b) $28 million in administrative and general expenses; and (c) $(410) million in other net changes to Power Charge Accounts (including operating reserves). This projection results in a revenue requirement of $3.308 billion.

Funds to meet these costs (in addition to surplus operating reserves) are projected to be provided from (a) $60 million from the Department's share of surplus power sales revenues; (b) $86 million of interest earned on Power Charge Account balances; and (c) $3.162 billion from Power Charge Revenues and Cost Responsibility Surcharge ("CRS") revenues from customers other than customers of the IOUs and DWR.

Table C-1 provides a quarterly projection of costs and revenues associated with the Power Charge Accounts for the 2008 Revenue Requirement Period.

TABLE C-1
POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE: RETAIL CUSTOMER POWER CHARGE CASH REQUIREMENT

Line	Description	Amounts for Revenue Requirement Period				
		2008 - Q1	2008 - Q2	2008 - Q3	2008 - Q4	Total
0	*Power Charge Accounts Expenses*					-
1	Power Costs	961	804	982	943	3,690
2	Administrative and General Expenses	7	7	7	7	28
3	Net Changes to Power Charge Account Balances	(47)	(85)	(182)	(96)	(410)
4	**Total Power Charge Accounts Expenses**	**921**	**726**	**807**	**854**	**3,308**
5	*Power Charge Accounts Revenues*					
6	Other Power Sales Revenues	23	16	7	14	60
7	Interest Earnings on Power Charge Account Balances	21	23	22	21	86
8	Total Power Charge Revenue Requirement	877	688	777	819	3,162
9	**Total Power Charge Accounts Revenues**	**921**	**726**	**807**	**854**	**3,308**

During 2008, the Department projects that it will incur the following Bond Related Costs: (a) $935 million for debt service on the Bonds and related Qualified Swap payments, payments of credit enhancement and liquidity facilities charges, and costs relating to other financial instruments and servicing arrangements in connection with the Bonds, and (b) $(21) million for changes to Bond Charge Account balances, resulting in total Bond Charge Account expenses of $914 million.

Funds to meet these requirements are provided from (a) $83 million in interest earned on Bond Charge Account balances, and (b) $831 million from Bond Charge Revenues (including CRS revenues from customers other than customers of the IOUs and DWR). There are no projected net transfers from Power Charge Accounts.

Table C-2 provides a quarterly projection of costs and revenues relating to the Bond Charge Accounts for the 2008 Revenue Requirement Period.

TABLE C-2
POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE:
RETAIL CUSTOMER BOND CHARGE CASH REQUIREMENT

Line	Description	Amounts for Revenue Requirement Period				
		2008 - Q1	2008 - Q2	2008 - Q3	2008 - Q4	Total
0	*Bond Charge Accounts Expenses*					
1	Debt Service Payments	75	633	76	151	935
2	Net Changes to Bond Charge Account Balances	133	(410)	162	94	(21)
3	**Total Bond Charge Accounts Expenses**	**208**	**223**	**238**	**245**	**914**
4	*Bond Charge Accounts Revenues*					
5	Interest Earnings on Bond Charge Account Balances	13	31	12	27	83
6	Retail Customer Bond Charge Revenue Requirement	195	192	226	218	831
7	**Total Bond Charge Accounts Revenues**	**208**	**223**	**238**	**245**	**914**

In aggregate, the Department's total cash basis expenses are projected to be $4.653 billion. Revenues from interest earned and other power sales are projected to be $229 million, and net changes in fund balances are projected to be $(431) million, resulting in combined customer revenue requirements of $3,992 billion.

D. ASSUMPTIONS GOVERNING THE DEPARTMENT'S PROJECTION OF REVENUE REQUIREMENTS FOR THE 2008 REVENUE REQUIREMENT PERIOD

This Supplemental 2008 Determination is based on a number of assumptions regarding retail customer load, demand side management and conservation, power supply, natural gas prices, off-system sales, administrative and general expenses as well as other considerations affecting the Department's revenues and expenses.

ESTIMATED ENERGY REQUIREMENTS

The Department obtained the utilities' most recent retail energy forecasts in May 2007. The Department reviewed the utilities' underlying forecast assumptions, including population growth, changes in employment and labor within the utility's service area, weather effects, growth in distributed generation, and annexation of the utility's service area by publicly owned utilities. In developing its bundled requirements forecast, the Department also reviewed forecasts of direct access and Community Choice Aggregation (CCA) in California. These assumptions are discussed in greater detail below.

Table D-1 shows the projected 2008 energy requirements forecast (quantified in gigawatt hours) for the PG&E, SCE and SDG&E service areas during 2008.

TABLE D-1
ESTIMATED ANNUAL ENERGY REQUIREMENTS

Service Area	Total Retail Requirements	Direct Access and CCA Requirements	Bundled Requirements
Pacific Gas & Electric	92,799	9,506	83,293
Southern California Edison	98,484	10,645	87,839
San Diego Gas & Electric	21,966	3,841	18,125
Total	213,249	23,992	189,257

DIRECT ACCESS

The Department's direct access estimates are based on data provided by each IOU in May and June 2007 and a review of monthly direct access reports produced by the Commission. The Department notes a slow but steady decline in direct access loads since the Commission suspended the right of bundled customers to elect direct access service, effective September 20, 2001. The Department regularly reviews each utility's monthly report to the Commission on current direct access load and service request changes to identify any substantive developments that would require action by the Department.

While the option to elect direct access service is suspended until the Department no longer supplies power under Division 27 of the Water Code (see California Water Code § 80110), the Commission recently initiated a Rulemaking (R. 07-05-025) to evaluate lifting the suspension of

direct access prior to 2015 when the last long-term contract expires[3]. The Commission states that it expects the proceeding to last longer than eighteen months. Given the manifold issues and the timing of the proceeding, the Department does not project that the suspension of direct access will be lifted during the 2008 Revenue Requirement period.

Table D-2 shows each IOU's direct access forecast, as a percentage of total retail loads, for 2008.

TABLE D-2
2008 DIRECT ACCESS FORECAST[4]

Service Area	Percent of Retail Load
Pacific Gas & Electric	7.92%
Southern California Edison	10.73%
San Diego Gas & Electric	17.49%
Total	**11.70%**

COMMUNITY CHOICE AGGREGATION

CCA refers to the ability of communities or public entities to aggregate load and procure all or a portion of their power requirements independent of the IOUs. Assembly Bill 117, adopted in 2002, modified the Public Utilities Code to allow local governments "…to elect to combine the loads of its residents, businesses, and municipal facilities in a community-wide electric buyers' program."[5] Significant volumes of CCA could lead to changes in Department rates to accommodate reduced IOU retail deliveries of Department power.

At present no load has left bundled utility service to form or become part of a CCA. However, the San Joaquin Valley Power Authority (SJVPA) filed an Implementation Plan with the Commission in January 2007 to form a CCA comprising approximately 5,000 GWh of load from fourteen different municipalities or public utility districts. That plan was certified by the Commission in May 2007. SJVPA plans to phase in its CCA program between November 2007 and November 2008. The SJVPA CCA load will reduce bundled load in both PG&E and SCE's service territories. To reflect the expected volume and timing of load migration noted in the SJVPA Implementation Plan, the Department has modified the 2008 load forecast for PG&E and SCE by 1,990,000 and 68,000 MWh, respectively.

Other communities have indicated a willingness to pursue CCA, including the City and County of San Francisco, several East Bay cities, the City of Chula Vista, Marin County, and the City of Fresno. Because the Department estimates that the process for aggregators to initiate feasibility studies and ultimately procure power on behalf of load to be eighteen to twenty-four months, we do not expect any load from these communities to migrate under the CCA program during the 2008 Revenue Requirement Period.

[3] Peevey Proposed Decision April 24, 2007, Order Granting Petition for Rulemaking and Instituting Rulemaking as to Whether, When, or How Direct Access Should be Restored.
[4] Figures in Table D-2 represent direct access as a percentage of total retail load for 2008. These percentages correspond to direct access loads forecast by the IOUs in 2007. The Department assumes that direct access load will remain constant from 2008 to 2009.
[5] Public Utilities Code, Section 331.1(a).

POWER SUPPLY RELATED ASSUMPTIONS

Three types of power supplies needed to meet the requirements of each IOU were considered by the Department in this Supplemental 2008 Determination: (a) IOU supplied resources; (b) supply from the Department's long-term power contracts; and (c) the residual net short of each IOU.[6]

Table D-3 below shows, for the 2008 Revenue Requirement Period, the estimated energy requirements for the customers of the IOUs, estimated supplies from generation by the three IOUs,[7] the resulting net short, the expected supply from the Department's long-term power contracts, off-system energy sales and the residual net short.

TABLE D-3
ESTIMATED NET SHORT ENERGY, SUPPLY FROM THE DEPARTMENT'S LONG-TERM POWER CONTRACTS AND THE DEPARTMENT'S ESTIMATE OF THE RESIDUAL NET SHORT

	Amount for the Revenue Requirement Period (GWH)
All Investor-Owned Utilities	
Energy Requirements After Adjustments	184,429
Supply from Utility Resources	119,556
Net Short	64,874
Supply from the Department's Priority Long-Term Power Contracts	41,326
Off-System Sales	(3,719)
Residual Net Short (Surplus)	27,266

Table D-4 shows, on a quarterly basis for the 2008 Revenue Requirement Period, estimated net short volumes in gigawatt-hours, supply from the Department's long-term power contracts and the residual net short.

[6] While the Department has calculated and presented the residual net short requirements of the IOUs, pursuant to the Act, the Department has not made any provision for the cost of the residual net short requirements in its Determination for the 2008 Revenue Requirement Period. For purposes of this 2008 Determination, the residual net short for each IOU equals the projected amount of wholesale energy remaining to be procured by such IOU on behalf of ratepayers in its service area.

[7] For purposes of this 2008 Determination, generation retained by the three IOUs is defined as the sum of generation owned by the IOUs, interruptible load, supply from contracts between the IOUs and qualifying facilities ("QFs") and other bilateral contracts.

TABLE D-4
NET SHORT, SUPPLY FROM THE DEPARTMENT'S LONG-TERM POWER CONTRACTS, OFF-SYSTEM SALES AND RESIDUAL NET SHORT IN 2008[1]

	Net Short (GWH)	Supply from Power Contracts (GWH)	Power Contract Costs (Millions of Dollars)	Off-System Sales Volumes (GWH)	Revenues from Off System Sales (Millions of Dollars)	(Residual Net Short) Spot Volume (GWH)
Q1-2008	15,838	9,742	849	(1,368)	(63)	7,464
Q2-2008	14,309	9,665	837	(1,228)	(49)	5,872
Q3-2008	17,994	11,392	1,023	(516)	(30)	7,119
Q4-2008	16,732	10,528	922	(607)	(43)	6,812
Total	64,874	41,326	3,632	(3,719)	(185)	27,266

[1]All costs and revenues are presented on an accrual basis.

UTILITY RESOURCES

The Department reviewed each utility's 2008 forecast of utility owned generation, qualifying facility ("QF") contract generation, and bilateral contract generation for consistency with the Department's own energy dispatch forecast. Where necessary, the Department updated its assumptions concerning QF contract terms and expiration dates, outage schedules, and net dependable resource capacity, among others, to reflect current details related to each IOU's resource portfolio.

HYDRO CONDITION ASSUMPTIONS

Normal hydrologic conditions are assumed for both California and the Pacific Northwest during 2008 and 2009. Neither the CEC nor the National Weather Service Northwest River Forecast Center has provided meaningful forecasts past the 2007 water year. Therefore, DWR has projected normal hydroelectric dispatch for the 2008 Revenue Requirement Period.

CONTRACT ASSUMPTIONS

During the 2008 Revenue Requirement Period, approximately 41,326 GWhs of energy is projected to be supplied on behalf of the retail electric customers of the IOUs through the Department's long-term power contracts. The terms and conditions of each contract have been reflected in the Department's market simulation, resulting in a projection of contract-specific, hourly energy dispatches to meet the projected energy requirements of each IOU's retail customers. The terms and conditions incorporated in the Department's market simulation include, among other details, must-take energy volumes and dispatchable contract capacities, contract heat rates and unit outage rates as well as scheduling limitations. During market simulation, all energy dispatches from the Department's dispatchable long-term power contracts occur based on dispatch of available power supply resources in merit order of the cost of dispatch and delivery of those resources, subject to transmission delivery constraints, and the effective cost of those constraints. In general, each incremental generating unit is dispatched only if the incremental cost of generating an additional MWh from that unit is less than the cost of alternative sources that can provide to the same location.

Table D-5 provides a listing of all of the long-term power contracts that will be operational during the 2008 Revenue Requirement Period and beyond, describing the term and capacity associated with each contract and the IOU to which the contract has been allocated.

With respect to the deliveries of power under the Department's long-term power contract with Calpine Energy Services, L.P formerly referred to as the "Long-Term Commodity Sale" transaction, also known as the "Calpine 2" contract, pursuant to an amendment entered into on December 7, 2007, 1000 MW of 7x24 energy deliveries through 2009 has been replaced, as of January 1, 2008, by 180 MW of unit-contingent dispatchable capacity during 2008 and 2009, with an extension option by DWR through 2012.

With respect to the deliveries of power under the Department's long-term power contract with Coral Power, LLC, consistent with historical practices, the seller's options to increase 6X16 deliveries by 10 percent has been assumed, as has an allocation of deliveries between NP15 and SP15 that provides all deliveries to NP15 during April through September, with some SP15 deliveries folded in during October through March. Coral provided notification of their 2008 delivery plan on November 1, 2007. The assumptions made in this Supplemental Determination are consistent with this plan.

With respect to the delivery of power under the Department's long-term power contract with Sempra Energy Resources, the estimated allocation of deliveries across delivery points for 2008 was based on the percentage distribution for calendar 2007 as reflected in Sempra's annual delivery plan applicable to 2007. Sempra's 2008 energy delivery plan was provided to the department in October, 2007 and is substantially consistent with the assumptions made by the Department.

Detailed contract terms can be found on the CERS website, http://cers.water.ca.gov

TABLE D-5
LONG-TERM POWER CONTRACT LISTING

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
Alliance Colton, LLC	4/23/2001 Renegotiated on 9/19/02	8/1/2001	12/31/2010	80	SCE
CalPeak Power—Panoche, LLC	8/14/2001 Renegotiated on 5/2/02	12/27/2001	12/27/2011	52.6	PG&E
CalPeak Power--Vaca Dixon, LLC	8/14/2001 Renegotiated on 5/2/02	6/21/2002	12/31/2011	51.9	PG&E
CalPeak Power--El Cajon, LLC	8/14/2001 Renegotiated on 5/2/02	5/29/2002	12/31/2011	50.9	SDG&E
CalPeak Power—Border, LLC	8/14/2001 Renegotiated on 5/2/02	12/12/2001	12/12/2011	51.6	SDG&E
CalPeak Power—Enterprise, LLC	8/14/2001 Renegotiated on 5/2/02	12/8/2001	12/8/2011	52.5	SDG&E
Calpine Energy Services, L.P. (Firm)	2/6/2001 Renegotiated on 4/22/02	1/1/2004	12/31/2009	1000	PG&E
Calpine Energy Services, L.P. (”Calpine 2”)	2/26/2001 Renegotiated on 4/22/02; Renegotiated on 12/7/2007	1/1/2008	12/31/2009, buyer option to 12/31/2012	180	PG&E
Calpine Energy Services, L.P. (Peaking Capacity)	2/27/2001 Renegotiated on 4/22/02	8/1/2002	7/31/2011	495	PG&E
Coral Power, LLC	5/24/2001	1/1/2006	6/30/2010	400	PG&E
"	"	7/1/2010	6/30/2012	100	PG&E
"	"	7/1/2002	6/30/2012	100	PG&E
"	"	7/1/2003	6/30/2012	175	PG&E
"	"	7/1/2004	6/30/2012	175	PG&E
Goldman Sachs Group, Inc. (formerly Allegheny Energy Supply Company, LLC)	3/23/2001 Renegotiated 6/10/03	1/1/2006	12/31/2011	800	SCE
GWF Energy, LLC	5/11/2001 Renegotiated on 8/22/02	9/6/2001	12/31/2011	95.8	PG&E

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
"	"	7/1/2002	12/31/2011	95.8	PG&E
"	"	6/01/2003	10/31/2012	170.5	PG&E
High Desert Power Project	3/9/2001 Renegotiated on 4/22/02	4/22/2003	3/31/2011	Up to 840	SCE
Kings River Conservation District	12/31/2002 Renegotiated 8/18/04	9/19/2005	9/18/2015	96	PG&E
Mountain View Power Partners, LLC	5/31/2001 Renegotiated on 10/1/02	10/1/2001	9/30/2011	66.6	SCE
PacifiCorp	7/6/2001	7/1/2004	6/30/2011	300	PG&E
City/County of San Francisco	12/30/2002	unknown	unknown	Est. 192	PG&E
Sempra Energy Resources	5/4/2001	1/1/2004	9/30/2011	1200	SCE
"	"	1/1/2008	9/30/2011	400	SCE
Sunrise Power Company, LLC	6/25/2001 Renegotiated on 12/31/02	6/01/2003	6/30/2012	572	SDG&E
(Wellhead) Fresno Cogeneration Partners	8/3/2001 Renegotiated on 12/17/02	8/20/2001	10/31/2011	21.5	PG&E
Wellhead Power Gates, LLC	8/14/2001 Renegotiated on 12/17/02	12/27/2001	10/31/2011	46.4	PG&E
Wellhead Power Panoche, LLC	8/14/2001 Renegotiated on 12/17/02	12/14/2001	10/31/2011	49.9	PG&E
Whitewater Energy Corp. (Cabazon Project)	7/12/2001 Renegotiated on 4/24/02	8/31/2002	12/31/2013	43	SDG&E
Whitewater Energy Corp. (Whitewater Hill Project)	7/12/2001 Renegotiated on 4/24/02	8/31/02 (partial)	12/31/2013	65	SDG&E
Williams Energy Marketing & Trading	2/16/2001 Renegotiated on 11/11/02	1/1/2008	12/31/2010	275	SDG&E

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
"	"	7/1/2003	12/31/2010	50	SDG&E
"	"	1/1/2008	12/31/2010	1045	SCE

The Department, in cooperation with representatives of the Attorney General's office and representatives of the Governor's staff, has continued its efforts to modify terms and conditions of the Department's long-term power contracts consistent with the requirements of the Act and applicable federal law. Three of the remaining original contracts have yet to be renegotiated from their original terms.

CONTRACT MANAGEMENT AND DISPOSITION ALTERNATIVES

The Power Charge component of the revenue requirement is directly related to the costs of power supplied under the Department's long-term power contracts. In considering changes to the contracts to modify its revenue requirements, the Department can (1) continue to use its contracts in their present form, (2) seek to modify the contracts through bilateral renegotiation with its counterparties, or (3) terminate the contracts.

Theoretically, the Department could unilaterally terminate one or more of its contracts. The terms of each of the Department's contracts provide that if the contract is terminated for reasons other than breach or default by the power-supplying counterparty to the contract, the Department is obligated to pay the entire remaining estimated value of the contract. Any such termination other than for an uncured default or breach by the seller would likely increase the Department's revenue requirements due to timing implications of the payments to the counterparty. In addition, energy no longer supplied by DWR would need to be replaced by the investor-owned utilities in either the short-term market or through new long-term power contracts with other suppliers, to the extent any portion of the energy supplied under a DWR contract is not surplus to the energy needs of the retail customers of the utilities. For this reason, under present market conditions and terms of the contracts, the Department does not believe that unilateral termination of any of the contracts would result in a reduction in its revenue requirements or overall ratepayer costs.

It is possible that additional power contract modifications, including termination of one or more contracts, could be agreed to between the Department and one or more of its long-term power supply counterparties prior to the end of the 2008 Revenue Requirement Period. As of the date of filing of this Supplemental 2008 Revenue Requirement Determination, the Department has not entered into any such final power contract modifications other than as already noted herein.

COST RESPONSIBILITY SURCHARGE

In a series of decisions, the Commission ordered certain classes of direct access, municipal and customer generating departing load, and community choice aggregation customers to pay a Cost Responsibility Surcharge ("CRS") related to historical stranded costs and ongoing above-market bundled costs associated with the Department's contracts. Included in the CRS is the DWR

Bond Charge component, which is assessed to pay debt service associated with the Department's 2002 bond issuance, and the DWR Power Charge component, which pays a portion of the above-market costs related to the DWR power portfolio.

Payments by direct access load, departing load, and CCA load of the DWR Bond Charge and the DWR Power Charge flow to the Department through Commission-established rates assessed on total usage. These revenues reduce one-for-one the bundled customer responsibility for DWR Bond Related Costs and Department Costs, respectively. In 2008, DWR Power Charge collections from direct access are limited by a maximum collections rate, or cap, established by the Commission.[8] Differences in the collection and accrual rate for the DWR Power Charge CRS are funded by bundled customers.[9]

SALES OF EXCESS ENERGY ASSUMPTIONS[10]

As with any retail provider of energy, from time to time, the combined IOU and Department power supply portfolios provide more energy than is needed to serve their retail customers. In general, these additional purchases result from differences between projected and actual IOU load. This excess energy is sold in wholesale markets by the IOUs under the current operating arrangements governing administration, operation and dispatch of DWR's contracts. On occasion, the price obtained for surplus power sales will be less than the price paid for power. However, these minimal energy transaction losses are an expected incident of appropriate power supply portfolio management, in that losses on sales from over-procurement are on average less than the costs associated with spot market purchases when there has been under-procurement. The income from such sales is used to partially offset the revenue requirements of the Department and the IOUs that would otherwise be recovered from retail customers.

On September 19, 2002, the Commission issued Decision 02-09-053, which, in part, determined that energy and resulting income from the sale of excess energy ("off-system sales") would be shared on a pro-rata basis between the Department and the IOUs. Projected revenue shares from the sale of excess energy, both the Department's and total IOU, are provided below in Table D-6.

TABLE D-6
PROJECTED SALE OF EXCESS ENERGY[1]

	DWR Volume	IOU Volume	Total Volume		DWR Revenue	IOU Revenue	Total Revenue		Weighted Average Price
	(GWh)	(GWh)	(GWh)		(Millions of Dollars)	(Millions of Dollars)	(Millions of Dollars)		($/MWh)
Q1-2008	356	1,012	1,368		16	46	63		46
Q2-2008	327	901	1,228		13	36	49		40
Q3-2008	138	378	516		8	22	30		58
Q4-2008	184	424	607		13	30	43		70
Total	1,005	2,714	3,719		51	134	185		50

[1]All revenues presented on an accrual basis

[8] DWR continues to monitor Commission proceedings addressing these matters.
[9] Undercollections from direct access are tracked in a balancing account and are returned to bundled customers when the collections cap exceeds the accrual rate.
[10] The Department is considering the affects of eliminating the sharing of surplus sales revenue on its Revenue Requirements

LONG-TERM POWER CONTRACT COST ASSUMPTIONS

Each long-term power contract identified in Table D-5 has been reviewed by the Department to determine the costs that will impact its revenue requirements during 2008. All applicable costs are reflected in the Department's electric market simulation along with previously noted operational considerations. The types of costs included in the Department's contract-specific projections include, but are not limited to, fixed energy, capacity, fixed operation and maintenance, variable operation and maintenance, scheduling coordinator fees, and fuel management fees. Total accrued long-term power contract costs, including requisite natural gas purchases, are projected to be $3.632 billion for the 2008 Revenue Requirement Period, as noted in Table D-4. Natural gas costs represent a significant component of the Department's total energy costs and are discussed below in greater detail.

For informational purposes, Table D-7 shows, for the 2008 Revenue Requirement Period, the expected average cost (in $/MWh) on a quarterly basis for the Department's long-term power contracts.

TABLE D-7
ESTIMATED POWER SUPPLY COSTS
(Dollars per Megawatt-Hour)

	Long-Term Priority Contracts
Quarter 1 – 2008	86
Quarter 2 – 2008	85
Quarter 3 – 2008	88
Quarter 4 – 2008	86

NATURAL GAS PRICE FORECAST AND FUELS ASSUMPTIONS

The natural gas price forecast supporting this 2008 Supplemental Determination is based on the NCI Fall 2007 Natural Gas Price Forecast ("NCI Fall 2007 Forecast") Base Case prepared by Navigant Consulting, Inc. ("NCI"), consultants to the Department. Assumptions underlying the NCI Fall 2007 Forecast include all significant supply and demand factors affecting the North American natural gas market such as the timing of major gas pipeline capacity changes, resource base additions and subtractions, gas demand, the price of crude oil, the timing and magnitude of certain liquefied natural gas ("LNG") capacities, imports and exports.

The NCI Fall 2007 Forecast was prepared based upon the GPCM natural gas forecast model and yields long term monthly gas prices. In order to account for short term fluctuations in the natural gas market, NYMEX prices are used in the initial twenty one months of the forecast. For the gas price forecast underlying this Supplemental 2008 Determination, the near term monthly prices at Henry Hub were revised on September 27, 2007 by averaging the then ten most recent daily settlement prices. The differences between the initial monthly price forecasts at Henry Hub and the recalculated monthly prices were used to proportionately adjust the forecasted prices at other market hubs, including PG&E Citygate and the Southern California Border. The results of these

adjustments to the NCI Fall 2007 Forecast are referred to as the NCI/DWR Fall 2007 Natural Gas Forecast ("NCI/DWR Fall 2007 Forecast").

Compared to the Base Case forecast underlying the 2008 Determination published August 22, 2007, prices in the NCI/DWR Fall 2007 Forecast Base Case supporting this Supplemental 2008 Determination are shown in Table D-8.

TABLE D-8
NATURAL GAS PRICE FORECAST COMPARISON AT HENRY HUB
(Nominal $/MMBtu)

	2008	**2009**
Gas Price Forecast – Supplemental 2008Determination	7.96	7.98
Gas Price Forecast – 2008 August 22, 2007 Determination	8.74	8.37
Difference	(0.78)	(0.39)

Table D-9 below lists the updated natural gas prices by quarter for 2008 and 2009 at two key California market hubs: PG&E Citygate and the Southern California Border.

TABLE D-9
NATURAL GAS AVERAGE PRICE FORECASTS
(Nominal $/MMBtu)

	Southern California Border		**PG&E Citygate**	
	2008	**2009**	**2008**	**2009**
Q1	7.75	8.81	7.99	9.13
Q2	7.17	7.52	7.62	8.01
Q3	7.44	7.43	7.85	7.87
Q4	8.10	7.40	8.49	7.81
Annual Average	**7.61**	**7.79**	**7.99**	**8.20**

As part of a 2002 settlement agreement with Williams Energy Marketing and Trading ("Williams") the Department entered into a Natural Gas Purchase Contract for natural gas deliveries beginning on January 1, 2004 and ending on December 31, 2010. On October 2, 2003, the CPUC issued Decision 03-10-016, which allocated fuel volumes related to the Williams Natural Gas Purchase Contract between SCE (64% in 2008) and SDG&E (36% in 2008).

During the 2008 Revenue Requirement Period, it is projected that the Natural Gas Purchase Contract will result in power cost savings of approximately $59 million, based on the difference between the contract fuel price of $4.21 and the Department's projected average fuel price of $7.61 at the Southern California Border pricing hub. For the purpose of determining power cost savings related hereto, the weighted average fuel price considered in this analysis accounts for related, seasonal variations in both the base case fuel price forecast and fuel volumes delivered under the Williams Natural Gas Purchase Contract in 2007.

GAS HEDGING EXPENSE

For the 2008 Revenue Requirement Period, the Department has reflected the impact of natural gas price hedges on a portion of the projected gas purchases that will be made to support the Department's power contracts. The hedging expenses and projected hedged volume are based on responses to information requests provided by the IOUs in April and May 2007 and monthly activity in the Department's Gas Hedging Account and the Department's own internal analysis.

The Department estimates that as of December 31, 2007, the IOUs had collectively secured, or developed reasonably firm plans to secure, hedges on behalf of DWR that establish the effective price for over 117 million MMBtu during calendar year 2008. The hedged volume represents approximately 60 percent of total projected IOU base case gas requirements (for fuel related to allocated DWR power contracts) for the 2008 Revenue Requirement Period. The Department has effectively hedged 18 million MMBtu of natural gas via firm price deliveries from the Williams contract during both the 2008 and 2009 Revenue Requirement Periods, and this annual volume is included in the aforementioned 117 million MMBtu for 2008. In June 2007, the Department was informed by Williams that certain of the Williams Energy Trading Co. assets, including the Department's contract with Williams, were being acquired by Bear Energy. As a part of this transaction, the Department has been informed that Williams will continue to perform the delivery of gas under the firm gas price contract referenced above. For purposes of this Determination, the Department assumes that the proposed Williams-Bear Energy transaction will not affect Williams' continued performance of this firm gas supply and delivery contract.

For purposes of this 2008 Determination, all proposed hedges use the margin requirement price at the NYMEX for gas contracts and the price for basis swaps quoted on February 14, 2008 on the NYMEX. The IOUs and the Department plan to augment NYMEX hedges with a portfolio of fixed for floating price swaps, call options and call spread options. The total gas hedging budget for the Supplemental 2008 Revenue Requirement is projected to be $30 million.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR MARKET REDESIGN AND TECHNOLOGY UPGRADE ASSUMPTIONS

The Department's Supplemental 2008 Revenue Requirement was developed using the same fundamental economic dispatch principles used in past revenue requirements. However, with the expected implementation of Market Redesign and Technology Upgrade ("MRTU") during 2008, the Supplemental 2008 Revenue Requirement uses a nodal market simulation model rather than the zonal model used in prior revenue requirements. The nodal market simulation projects the amount of DWR contract energy delivered to serve customer load and any surplus sales used to benefit the end use customers in each IOU service area. The Supplemental 2008 Revenue Requirement does not include any congestion costs, including costs reflected as the difference in energy prices between the load aggregation point and the energy injection point, or additional costs for transmission losses due to MRTU implementation.
Rather than being part of the Department's Revenue Requirement, these costs are assumed to be borne by the IOUs consistent with previous CPUC orders and decisions, specifically D. 02-12-069 and D. 07-03-025 and Appendices A – C.

ADMINISTRATIVE AND GENERAL COSTS

The Department's administrative and general costs of $28 million consist of $23 million for appropriated budget expenditures including funds for labor and benefits, pro rata charges for services provided to the power supply program by other State agencies and $5 million for consulting services for development and monitoring of the revenue requirements, litigation and dispute resolution support, power contract management, and financial advisory services for managing the $10 billion debt portfolio and related reserves.

FINANCING RELATED ASSUMPTIONS

For purposes of calculating the interest earnings on account balances, the Department assumes a 5.04 percent earnings rate for the Debt Service Reserve Account and a 5.0 percent earnings rate for all other accounts during the 2008 Revenue Requirement Period.

The Department currently has $3.274 billion of fixed rate bonds outstanding, $3.960 billion of hedged variable rate bonds outstanding that have corresponding interest rate hedges in place to convert debt service to fixed rate and $2.820 billion of unhedged variable rate debt. The projected average interest rate for all fixed rate bonds for the 2008 Revenue Requirement Period is 5.286 percent. The projected average interest rate for all hedged variable rate bonds is 3.342 percent.

For purposes of calculating the interest accruing on unhedged variable rate bonds during 2008, as well as any future revenue requirement periods, interest is assumed to accrue at a rate equal to the greater of (a) 130 percent of the highest average interest rate on such Variable Rate Bonds in any calendar month during the twelve (12) calendar months ending with the month preceding the date of calculation, or such shorter period that such Variable Rate Bonds shall have been Outstanding, or (b) 4.0 percent. For the 2008 Revenue Requirement Period, on the basis of these assumptions, interest rate on Variable Rate Bonds is projected to be 4.695 percent.

The Department projects that the amount of Bond Charge Revenues required for the 2008 Revenue Requirement Period will be $831 million.

ACCOUNTS AND FLOW OF FUNDS UNDER THE BOND INDENTURE

General information on the Accounts and flow of funds under the Bond Indenture, which has not changed since the bonds were issued in 2002, is contained in the Department's prior Determinations of Revenue Requirements, copies of which have been incorporated into the administrative record supporting this Determination.

Information specific to certain Accounts for this 2008 Revenue Requirement Determination follows.

OPERATING ACCOUNT

The Department has covenanted in the Bond Indenture to include in its revenue requirements amounts estimated to be sufficient to cause the amount on deposit in the Operating Account at all times during any calendar month to equal the Minimum Operating Expense Available Balance ("MOEAB"). The Bond Indenture leaves to the Department the determination as to how far into the future this minimum test of sufficiency should be met. Moreover, the covenant concerns the minimum amount required to be projected to be on deposit, and leaves to the Department the determination as to what total reserves are appropriate or required in the fulfillment of its duties under Section 80134 of the Act.

The Department determines the MOEAB at the time of each revenue requirement determination and is to be an amount equal to the largest projected difference between the Department's projected operating expenses and the Department's projected Power Charge revenues during any one month period during the revenue requirement period, taking into account a range of possible future outcomes (i.e., "stress cases").

For the purposes of this Supplemental 2008 Determination, the Department has determined the MOEAB to be $337 million. The Department projects to exceed the MOEAB at all times during 2008. The Department has determined that the amount projected to be on deposit in the Operating Account, including the amount therein that acts as a reserve for Operating Expenses, is just and reasonable, based in part on the following: (1) potential gas price volatility, (2) potential gas price escalation, (3) year-over-year revenue requirement volatility, and (4) credit rating agency and credit and liquidity facility considerations, as well as the factors discussed below under "Sensitivity Analysis" and in Section E—"Key Uncertainties in the Revenue Requirement Determination".

OPERATING RESERVE ACCOUNT

The Operating Reserve Account Requirement ("ORAR") is to be calculated, in respect of each Revenue Requirement Period, as the greater of (a) the largest aggregate amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any consecutive seven calendar months commencing in such Revenue Requirement Period and (b) 12 percent of the Department's projected annual Operating Expenses, provided, however, that the projected amount will not be less than the applicable percentage of Operating Expenses for the most recent 12-month period for which reasonably full and complete Operating Expense information is available, adjusted in accordance with the Indenture to the extent the Department no longer is financially responsible for any particular Power Supply Contract. All projections are to be based on such assumptions as the Department deems to be appropriate after consultation with the Commission and taking into account a range of possible future outcomes (i.e., "Stress Cases").

Additionally, the ORAR shall include, but shall not be limited to, the Priority Contract Contingency Reserve Amount ("PCCRA"). The PCCRA is the maximum amount projected by the Department to be payable by the Department under and pursuant to Priority Long Term Power Contracts in any calendar month during such Revenue Requirement Period. All projections are to be based on such assumptions as the Department deems to be appropriate after consultation with the Commission and Stress Cases.

Based on the Stress Cases described below under "Sensitivity Analysis", the ORAR for the 2008 Supplemental Revenue Requirement Period is determined by the Department to be $548 million, reflecting an amount equal to the PCCRA.

DEBT SERVICE RESERVE ACCOUNT

For purposes of calculating the amount of the Debt Service Reserve Requirement from time to time, interest accruing on Variable Rate Bonds during any future period will be assumed to accrue at a rate equal to the greater of (a) 130 percent of the highest average interest rate on such Variable Rate Bonds in any calendar month during the twelve (12) calendar months ending with the month preceding the date of calculation, or such shorter period that such Variable Rate Bonds shall have been outstanding, or (b) 4.0 percent. For the 2008 Revenue Requirement Period, the Department will calculate projected interest on unhedged Variable Rate Bonds at 4.695 percent.

For the 2008 Revenue Requirement Period, the Department has determined the Debt Service Reserve Requirement to be $943 million. The Department projects to maintain this amount at all times during the Revenue Requirement Period.

SENSITIVITY ANALYSIS

The Rate Agreement requires the Department to evaluate its costs and cash flows on a monthly basis and to notify the Commission of its Retail Revenue Requirements no less than once each year, thereby ensuring that Bond Charges and Power Charges are adequate to meet financial obligations associated with the Bonds and the power supply program. From the date the Department first initiates any necessary revised Retail Revenue Requirement proceeding, it expects no more than seven months will elapse before it receives modified levels of revenues associated with the filing. As explained in prior Department revenue requirement determinations, during this seven month period the Department would endeavor to identify any material changes in its revenue requirement, proceed through its own administrative determination of its modified revenue requirement, notify the Commission of the new revenue requirement for purposes of allocating the costs among customers, and finally begin receiving the modified level of revenue. In order to ensure its ability to meet its financial obligations during this seven month period, the Department must maintain reserves that are adequate to meet normal anticipated expenses, unexpected variations in these expenses, and/or reductions in revenue receipts resulting from factors beyond the Department's control. The determination of reserve levels is made by the Department, considering such factors as the potential variations in revenue receipts and power supply program expenses, changes in key variables affecting customer energy requirements, IOU controlled or "retained" generation ("URG") production levels, changing natural gas prices, and Department contract operations, among other factors.

To assess the adequacy of reserve levels, the Department and its consultants have prepared an additional assessment of Stress Cases based on changes in certain key expense and operating assumptions. The Stress Cases considered in this assessment reflect a sampling of groups of changes in key assumptions that could affect Department expenses and revenues. The Stress Cases are not intended to reflect all possible scenarios, nor are they intended to reflect only those most likely to occur. For the Stress Cases, a market simulation was performed to generate revised net short requirements and associated power supply costs. These revised forecasts were

used to generate revised cash flow projections for the Department. These revised results were compared against the base estimate of cash flow projections (the "Base Case").

CASE 1

This Stress Case focuses on decreased Bond Charge and Power Charge revenues resulting from lower sales to Department customers, and increased costs of providing energy under existing contracts.

Higher costs are driven primarily by increased fuel costs. This Stress Case utilizes a higher natural gas price forecast than is presented in Table D-9. This Stress Case gas price forecast, shown in Table D-10, was developed using basic statistical methods to define a high-end range of gas prices at the Henry Hub, Southern California Border and PG&E Citygate delivery points. These are the relevant primary delivery points for natural gas that would be procured to support DWR's long-term contracts.

TABLE D-10
STRESS CASE – NATURAL GAS PRICE FORECASTS
(Nominal $/MMBtu)

	Henry Hub	Southern California Border	PG&E Citygate
	2008	**2008**	**2008**
Q1 – 2008	14.78	14.07	14.46
Q2 – 2008	13.62	12.75	13.49
Q3 – 2008	13.99	13.26	13.93
Q4 – 2008	15.09	14.58	15.22
Annual Average	**14.37**	**13.66**	**14.27**

The Stress Case gas price forecast for each delivery point was developed using a set of historical monthly prices from the first of the month starting in April 1998 through April 2007 for each delivery point and identifying the distribution function that best fits the data through the use of specialized statistical software. Using the identified distribution functions, a Monte Carlo simulation was performed on each monthly Base Case gas price forecast to identify a gas price with a 99 percent probability of all gas prices within that specific distribution falling below it – presuming the Base Case gas price forecast is the mean point of the distribution. This gas price was then used as the Stress Case gas price forecast for that specific delivery point and month. While this methodology appears to provide the best method of statistically identifying a reasonable high-end range for gas prices, no statistical method will perfectly capture the variability in gas prices.

Gas hedges can be used to reduce the impact of changes in the spot market for gas. Based on information provided by the IOUs, the Department has included the impact of actual and planned gas hedges in place as of September 30, 2007. These hedges, in many instances, limit the price of natural gas purchases under the Stress Cases to levels below the Stress Case gas price forecast for those volumes and time periods for which the hedges are in place.

Lower customer sales by the Department are driven primarily by a decrease in the net short energy requirements, which can occur as a result of increased URG and/or decreased customer load. In this case, URG is increased by assuming California and Pacific Northwest hydroelectric production at 125 percent of normal for 2008 and 2009.

Lower loads are estimated in this case by assuming cooler-than-normal summers during 2008 and 2009, and by assuming increased non-programmatic conservation. The level of decreased customer load due to temperature variation is simulated by decreasing the Base Case total monthly load forecast for 2008 and 2009 by 3.3 percent, 3.6 percent, 5.1 percent and 4.4 percent for June, July, August, and September, respectively. In addition, an increase in the assumed level of non-programmatic conservation (above the Base Case) results in decreases in total annual load of four percent in 2008 and two percent in 2009. Lower electric loads result in a Stress Case for Department revenue because the fixed component of Department energy

contracts must be allocated over fewer MWh of retail electric sales, thereby increasing the Department's required recovery cost per MWh.

CASE 2

This Stress Case focuses on increased costs of providing energy under existing contracts, and considers increased contract dispatch due to higher customer load and reduced URG.

Higher costs are driven primarily by increased fuel costs. As in Case 1, this Stress Case utilizes the higher natural gas price forecast that is presented in Table D-10.

Higher customer sales by the Department are driven primarily by an increase in the net short, which can occur as a result of decreased URG and/or increased customer load. In this case, URG is decreased by assuming California and Pacific Northwest hydroelectric production at 75 percent of normal in 2008 and 2009. URG is further decreased by assuming an unplanned outage at one southern California nuclear power plant unit from January 2008 through March 2008 and at one northern California nuclear power plant unit from April 2008 through March 2009. The expected impact of this type of an assumption is to increase the amount of energy dispatched from the Long-Term Priority Contracts.

Higher loads are estimated in this case by assuming load growth rates that are 2.0 percentage points higher than those assumed in the Base Case in 2008 and 1.4 percent higher in 2009. It is assumed that this growth occurs as a result of the combination of accelerated economic growth in California and decreases in the expected amount of achieved non-programmatic conservation. In addition, load is increased by assuming the existence of warmer-than-normal summers in 2008 and 2009. The level of increased customer load due to temperature variation is simulated by increasing the Base Case total monthly load forecast (inclusive of the accelerated growth rates described above) in 2008 and 2009 by 4.4 percent, 4.8 percent, 6.8 percent, and 5.9 percent for June, July, August, and September, respectively.

E. POWER CONTRACT SETTLEMENT SUMMARY

The California Parties, which include the Governor's Office, California Attorney General's Office, CPUC, California Electricity Oversight Board, the Department and IOUs have been participating in FERC proceedings to recover excess electricity costs incurred by ratepayers since 2001. These FERC proceedings have led to several settlement agreements between the California Parties and the responsible energy suppliers. As one of the California Parties, the Department has received distributions from these energy suppliers that have been paid to settle claims against them. These settlement distributions reduce Department costs and, as a result, decrease the Department's revenue requirement. Settlement agreements for Enron Corporation, Mirant Corporation, Reliant Energy, and Williams Energy Marketing and Trading, as well as the April 18, 2006 Sempra Energy Resources arbitration are described in the Department's 2007 Determination of Revenue Requirements, a copy of which has been incorporated into the administrative record supporting this Determination.

Settlement agreements in excess of $1 million each entered into since the Department's 2007 Determination, and additional monies received from earlier settlements, are detailed below. All settlement agreements entered into since the Department's 2007 Determination, and additional monies received from earlier settlements, have been considered in projecting the Department's beginning account balances and costs for the 2008 Revenue Requirement Period.

ENRON

The Department received semi-annual distributions in October 2006, April 2007 and October 2007 totaling nearly $31 million from Enron Corporation Settlement unsecured bankruptcy claims. These monies are in addition to nearly $53 million received previously from the August 2005 settlement agreement.

BP ENERGY COMPANY

On April 19, 2007, the California Parties executed a Master Settlement Agreement with BP Energy Company. The settlement with BP Energy Company resolved claims related to energy overcharges against California ratepayers during 2001. On May 4, 2007, the Department received $18 million due from the aforementioned settlement agreement.

RELIANT ENERGY

On February 23, 2007, the Department received an additional $2 million from the Reliant Energy Settlement dated October 12, 2005.

In addition to these prior year settlements, the Department has been in discussion with some of its power supply counterparties regarding settlements of certain operational disputes associated with the performance under some of the long-term power supply contracts. Resolutions of a few of these disputes were pending as of the date of this revenue requirement determination and potential amounts of such settlements could not be incorporated herein.

F. KEY UNCERTAINTIES IN THE REVENUE REQUIREMENT DETERMINATION

There are a number of uncertainties facing the Department that may require material changes to its revenue requirements for the 2008 Revenue Requirement Period after this Supplemental 2008 Determination. Several risk factors are outlined below and additional information may be found in each of the bond financing Official Statements, which may be obtained from the Treasurer of the State of California

1. Determination of Power Charges and Bond Charges; possible use of amounts in the Bond Charge Collection Account to pay Priority Contract Costs:
   a. Potential administrative and legal challenges to DWR's revenue requirements;
   b. Potential litigation regarding inclusion of DWR Priority Contract Costs in its Retail Revenue Requirement; and
   c. Application and enforcement of the Rate Agreement's Bond Charge rate covenant.

2. Collection of Bond Charges and Power Charges:
   a. Potential rejection of Servicing Arrangements or other disruption of servicing arrangements.

3. Certain risks associated with DWR's Power Supply Program:
   a. Long-term power contracts:
      i. Impact of renegotiated contracts;
      ii. Off-system sales volume and price variability;
      iii. Failure or inability of the suppliers to perform as promised including but not limited to any failure to add new capacity to the grid or a possible rejection of a contract in bankruptcy;
   b. Gas price volatility; and
   c. "Block Forward Contracts" consolidated actions.

4. Potential increases in overall electric rates:
   a. Changes in general economic conditions;
   b. Energy market-driven increases in wholesale power costs;
   c. Fuel costs;
   d. Hydro conditions and availability;
   e. Market manipulation; and
   f. Actions affecting retail rates.

5. Potential decrease in DWR customer base:
   a. Direct Access; and
   b. Load departing IOU service.

6. Potential variance in dispatch of DWR contracts:
   a. Actual vs. forecast load variance;
   b. Dispatch coordination between IOUs and DWR; and
   c. Modification of sharing of surplus power sales revenues.

7. Uncertainties relating to electric industry and markets:
   a. Electric transmission constraints;
   b. Gas transmission constraints; and
   c. CAISO implementation of its Market Redesign and Technology Upgrade.

8. Uncertainties relating to government action:
   a. California Emergency Services Act;
   b. Possible State legislation or action; and
   c. Possible Federal legislation or action.

G. JUST AND REASONABLE DETERMINATION

PRIOR DETERMINATIONS

Each new revenue requirement determination builds, to the extent necessary or appropriate, on the various preceding determinations. Successive determinations incorporate the information from each previous determination into the supporting administrative record. The Supplemental 2008 Determination and prior determinations are available for review on the DWR-CERS website by interested persons, and the supporting materials are available at the CERS office in Sacramento, subject to applicable non-disclosure requirements.

Determination	Date Issued
2001-2003, including Reexamination and Redetermination for 2001-2002	August 16, 2002
Reconsideration of Just and Reasonableness of 2001 - 2003	August 19, 2004
2003 Supplemental	July 1, 2003
2004	September 18, 2003
2004 Supplemental	April 16, 2004
2005	November 4, 2004
Revised 2005	March 16, 2005
2006	August 3, 2005
Final 2006	October 27, 2005
2007	August 2, 2006
Revised 2007	October 30, 2006
2008	August 22, 2007
Revised 2008	October 31, 2008
Supplemental 2008	February 15, 2008

THE SUPPLEMENTAL 2008 DETERMINATION

PUBLIC PROCESS

On December 27, 2007, the Department issued its Proposed Supplemental Revenue Requirement Determination for the period January 1, 2008 through December 31, 2008. This document was made available for public review and comment. The Department provided interested persons with quantitative results from its PROMOD market simulation, the amended and restated Calpine 2 Contract and Financial Model, subject to applicable non-disclosure requirements. Interested persons were advised to submit comments no later than January 17, 2008.

On January 17, 2008 the Department received comments from PG&E, SCE and SDG&E. No other persons submitted comments. The Department reviewed and considered each comment and took action as appropriate. The complete comments are included in the administrative record and are referenced in Section J.

JUST AND REASONABLE DETERMINATION

After assessing the administrative record, the Act, the Regulations, Bond Indenture requirements and the Rate Agreement. , the Department finds this Supplemental 2008 Revenue Requirement for the period of January 1, 2008 through December 31, 2008, to be just and reasonable.

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H. MARKET SIMULATION

Wholesale power costs in the western United States are driven by a multitude of factors. These include weather and related electricity demand, precipitation and related hydropower production, supply and price of natural gas and coal, power transfer capability of major interties, operating costs, outages and retirement of generating plants, and the cost, fuel efficiency, and timing of new generating resource additions. The Department analyzed the fundamental drivers underlying the electricity market by generating computer simulations of market activity throughout the Western Electricity Coordinating Council ("WECC") region.

As part of its market report and simulation in developing the 2008 Revenue Requirement, the Department considered all items in the above paragraph and the following:

- California ISO Market Redesign and Technology Upgrade;
- Potential impacts of market redesign on the Department's long-term contracts and revenue requirements;
- Use of PROMOD IV as a market simulation tool;
- Analysis of retirement and additions of WECC generation resources; and
- California ISO Locational Marginal Price and Congestion Revenue Rights proposals.

More detailed information about the market simulation utilized by the Department, including descriptions of the inputs and assumptions is referenced in Section J of the 2008 Revenue Requirement.

I. COMMENTS RECEIVED ON THE SUPPLEMENTAL 2008 DETERMINATION AND THE DEPARTMENT'S RESPONSES

On December 27, 2007, the Department issued its Proposed Supplemental Revenue Requirement Determination for the period January 1, 2008 through December 31, 2008. DWR made this document available for public review and comment. The Department provided interested persons with quantitative results from its PROMOD market simulation, the amended and restated Calpine 2 contract and Financial Model, subject to applicable non-disclosure requirements. Interested persons were advised to submit comments no later than January 17, 2008.

The Department received comments from PG&E, SCE and SDG&E. No other persons submitted comments. The Department reviewed and considered each comment and took action as appropriate. The comments and the Department's responses are reviewed below.

Summary of Comments of Pacific Gas and Electric

PG&E Comment #1:

In its January 17, 2008 comments, PG&E states that the sole significant reason for the Proposed Supplemental Determination appears to be DWR's decision to terminate its Calpine 2 contract for 1000 MW and replace it with a 180 MW unit-contingent dispatchable contract.

Response: The sole significant reason for a Supplemental Revenue Requirement Determination is DWR's decision to amend and restate the Calpine 2 contract. Contrary to PG&E's assertion, DWR did not terminate one contract and replace it with another.

PG&E Comment #2:
PG&E quotes from the 2008 Proposed Supplemental Revenue Requirement that "DWR will make its just and reasonable determination after review of the comments from interested parties" and then comments, "Nonetheless, on December 14, 2007, DWR wrote to the California Public Utilities Commission (CPUC), and stated that . . . [the amended and restated] Calpine 2 contract provides net savings to statewide ratepayers."

Response: The just and reasonable determination referenced in the 2008 Proposed Supplemental Revenue Requirement is the determination with respect to DWR's 2008 Supplemental Revenue Requirement. Compared to the 2008 Revenue Requirement Determination, this 2008 Supplemental Revenue Requirement reduces the revenues that the IOUs must collect from their ratepayers by $630 million. The CPUC will allocate this reduction through the existing or amended Allocation Order.

The Department has followed its defined process for public participation in the determination of its 2008 Supplemental Revenue Requirement. As it has done for all previous revenue requirement determinations, the Department considered the entire portfolio of power contracts, electricity prices, fuel costs and contract dispatch along with many other factors to project the costs of the Department for the period of January 1, 2008 through December 31, 2008. Further, the Department considered the administrative record, the Act, the Regulations, Bond Indenture requirements and the Rate Agreement. An inference may be drawn from PG&E's comment that PG&E believes that DWR's statement about the Calpine 2 contract in a communication with the CPUC is not consistent with the revenue requirement determination process. PG&E misconstrues the purpose of DWR's communication with the CPUC, which was intended to provide a full description of the Calpine 2 amendment in order to support the CPUC in its role. Such a communication is not inconsistent with the process by which DWR makes the determination on the revenue requirement.

PG&E Comment #3:
PG&E states that on December 21, 2007, Assemblyman Levine, the Chair of the California Assembly Committee on Utilities and Commerce, wrote DWR requesting various documents, analyses and information regarding the impact of the Calpine 2 amendment and restatement on electricity costs, supplies and reliability. PG&E further states that information on net savings, including detailed assumptions and analysis, are important for the public and other interested parties to assess the net ratepayer's costs and benefits of DWR's amendment of the Calpine contract.

Response: DWR received Assemblyman Levine's letter. DWR responded to the letter and provided materials on January 15, 2008 and February 7, 2008. DWR agrees that such information is relevant to reviewing the costs and benefits of the amended and restated contract. The materials DWR provided to Assemblyman Levine have been provided to PG&E. The letters to Assemblyman Levin are provided as Attachment A to this Supplemental Revenue Requirement. The voluminous materials referenced in the letter to Assemblyman Levin are available for review at the California Energy Resources Scheduling Division (CERS) of DWR, located at 3310 El Camino Avenue in Sacramento, California. Any interested party can contact Iryna Kwasny at (916) 574-2009 to arrange to review the materials.

PG&E Comment #4:
PG&E states that it reserves its rights to provide additional comments.

Response: The comment period ended on January 17, 2008 and DWR may not consider additional comments without reopening the comment period. Once the supplemental revenue requirement has been determined, requests for rehearing may be filed and DWR will consider any such requests as required by law.

Reopening of the comment period is addressed in 23 CCR Section 513(a): "If following a notice pursuant to section 512 the department identifies significant material that it intends to rely upon in making its determination, but which was not identified in the proposed determination, the department shall provide notice of such additional material to those persons who received the original notice…." Although Attachment A references materials available to the public, DWR does not deem these documents significant in the determination on the revenue requirement and does not rely on those documents for that purpose. The documents are made available in order to provide maximum disclosure to the public and to be responsive to comments submitted.

PG&E Comment #5:
PG&E requested that DWR provide its detailed analysis – including inputs, market data, sources of assumptions and analytical basis – of the customer impacts of the amended and restated Calpine 2 contract. This request included (1) the amount of replacement power and costs that PG&E customers will incur, (2) a reconciliation of the difference in replacement power needed by PG&E and its "residual net short" determination, (3) the impacts on PG&E customers of the overall reduced adequacy of resources, (4) an explanation of why the replacement product was selected, and (5) the value of the 180MW new peaking capacity.

Response: The available information that is responsive to this comment is contained in information previously provided to the Legislature, PG&E and the CPUC. That information is available for review at the California Energy Resources Scheduling Division (CERS) of DWR, which is located at 3310 El Camino Avenue in Sacramento, California. Any interested party can contact Iryna Kwasny at (916) 574-2009 to arrange to review the materials.

PG&E Comment #6:
PG&E requested "…a better understanding of how DWR determined the amount of energy DWR forecasts from the PacifiCorp contract."

Response: In its comments on the 2008 Revenue Requirement process, PG&E noted that DWR's forecasted annual dispatch is approximately 50 percent of the actual contract dispatch for the 12 month period from September 2006 through August 2007. This disparity remains during the Supplemental Revenue Requirement Determination. As noted in previous responses to PG&E comments, the Department recognizes this disparity but also notes that the forecasted annual dispatch is approximately 80 percent of the actual calendar year 2006 contract dispatch. The Department and PG&E have projected dispatch levels for the PPM[11] Energy contract that are significantly different, and staff for both the Department and PG&E have been working together to try to determine the source of the variance.

The dispatched energy forecasts for the PPM Energy contract that are developed by DWR are developed in the same manner that all other resources in the entire Western Electricity Coordinating Council ("WECC") region are developed. The Department utilizes a production simulation model for the entire WECC region that considers a number of factors, including:

- Electricity demand, which varies hourly, seasonally and in response to weather events
- The supply and price of natural gas and coal
- Precipitation and related hydropower production
- The operating costs of generating plants
- Plant outages and retirements
- The cost, timing and location of new generation
- The power transfer capability of major interties between regions

All of these factors interact to determine the market clearing price of electricity, which, along with resource marginal cost of production, load levels, availability of other resources and transmission capability, are primary drivers of individual resource dispatch levels. The primary determinant in the difference in the projected dispatch levels developed by PG&E and the Department is related to assumed market clearing prices of electricity. Because the PPM contract is a dispatchable contract, it will only be projected to dispatch if it is economical to do so (i.e. the marginal cost of dispatching the plant is less than other available resources that can be used to meet load requirements at a given time). The market clearing price is a proxy for other available resources. The Department's market simulation projections of average monthly market clearing price in northern California in 2008 are approximately 16% lower than PG&E's projections. In a production simulation analysis, this will lead to a lower level of dispatch from the PPM dispatchable contract than PG&E (with higher market clearing prices) would project.

At this time, the Department has determined that its current forecast and its underlying assumptions are just and reasonable and does not plan to revise the forecasted contract dispatch.

PG&E Comment #7:
PG&E requested that the Department clarify the basis for the reduction in Operating Reserves of $93 million

[11] Note that while PG&E refers to the "PacifiCorp" contract, the contract is with PPM Energy, which is no longer associated with PacifiCorp. The Department refers to the contract as the PPM Energy contract herein

Response: The Department determines the target minimum balance for its Operating Account in each revenue requirement determination. For a discussion of how the amount is determined, please see the section entitled "Operating Account" in this Determination.

In certain revenue requirement periods, the Department projects to exceed the target minimum amount projected to be on deposit in the Operating Account, to mitigate the affects of (1) potential gas price volatility, (2) potential gas price escalation, (3) year-over-year revenue requirement volatility, and (4) credit rating agency and credit and liquidity facility considerations, as well as other factors.

Based on discussions with the Department's advisors and rating agencies, the year over year revenue requirement volatility has been the key factor in determining whether the Department projects to exceed or meet the target minimum balance in the Operating Account.

In the 2008 Revenue Requirement submitted to the CPUC on October 31, 2007, the Department maintained an amount above the minimum required amount to avoid projected average power charge increases through 2011. In the Supplemental 2008 Revenue Requirement, the Department projects to maintain an amount over the minimum required to avoid a projected average power charge increase through 2009 instead of through 2011. This change in time period results in the $93 million reduction in the operating reserves.

The Department changed the period of time over which it examines future power charge effects for two reasons. First, the final monthly payment of approximately $44 million associated with the original Calpine 2 contract was projected to be made in January, 2010. Second, the decrease in the Department energy deliveries related both to the Calpine 2 restructuring and natural termination of other contracts are projected to result in a reduction in the risk of recovery of the Department's power cost from the ratepayers of the utilities. For these reasons, it is unnecessary to retain the same level of operating reserves as exists in the existing 2008 revenue requirement. This enabled the reduction of the projected Operating Account balances.

Summary of Comments of Southern California Edison

SCE Comment #1:

In its January 17, 2008, comments, SCE requests that the Department revise two portions of the Revenue Requirement section which addressed the CAISO's Market Redesign and Technology Upgrade ("MRTU"). The first suggested revision asks that the Department strike the phrase "or additional costs for transmission losses due to MRTU implementation" from the following paragraph.

"The Department's Proposed Supplemental 2008 Revenue Requirement was developed using the same fundamental economic dispatch principles used in past revenue requirements. However, with the expected implementation of Market Redesign and Technology Upgrade ("MRTU") during 2008, the Proposed Supplemental 2008 Revenue Requirement uses a nodal market simulation model rather than the zonal model used in prior revenue requirements. The nodal market simulation projects the amount of DWR contract energy delivered to serve customer load and any surplus sales used to benefit the end use customers in each IOU service area. The

Proposed Supplemental 2008 Revenue Requirement does not include any congestion costs, including costs reflected as the difference in energy prices between the load aggregation point and the energy injection point, *or additional costs for transmission losses due to MRTU implementation*. Rather than being part of the Department's Revenue Requirement, these costs are assumed to be borne by the IOUs consistent with previous CPUC orders and decisions, specifically D. 02-12-069 and D. 07-03-025 and Appendices A – C".

Response: Since the Department's power program came into existence in 2001, the Department has not projected transmission cost in its revenue requirement projections. The only costs projected are, (1) the contract cost which includes payments for capacity, fuel O&M and other costs required by contractual obligations, (2) the cost associated with implementing fuel price hedging, and (3) the administrative and general obligations of the Department.

From January 17, 2001 through December 31, 2002, SCE accepted financial responsibility for ISO costs as provided in that certain Letter Agreement, dated February 28, 2002, as amended as of March 18, 2002. This agreement is incorporated by reference as Attachment I of the Servicing Order adopted by the CPUC pursuant to Decision 07-03-025. More specifically, since the effective date of the Operating Order, the IOUs accepted all the CAISO costs incurred attributable to load and resources as provided in Exhibit D thereto. As stated in the Department's November 1, 2007 memo, the Proposed Supplemental 2008 Revenue Requirement reflects the Department's assumption that the costs due to MRTU implementation will be borne by the IOUs consistent with the Operating and Servicing Arrangements.

SCE is correct that the Department's power charge is collected on energy delivered to its customers in each IOU service area, and such energy is less than the amount generated due to transmission and losses, however the cost associated with transmission losses is not projected nor is it included in the Department's Revenue Requirements.

Consistent with the Department's November 1, 2007 memo, the Department continues to meet with the representatives of the IOUs to evaluate changes in remittance methodologies, including exploring the elimination of surplus energy sale revenue sharing arrangement in light of the ISO's MRTU. The details of any changes resulting from these discussions are expected to be reflected as revisions to the currently effective Operating and Servicing Arrangements.

SCE Comment #2:
SCE asks that the Department clarify the following paragraph - "Currently, the Department's power is provided through bilateral trades. When MRTU is implemented, power will be delivered through the CAISO markets. On November 1, 2007 DWR requested that the Commission direct the IOUs to continue remitting to DWR at the remittance rate on all contract energy since the energy benefits the retail customers. Any energy in excess of customer load would become a surplus sale with the energy and revenues being shared by the IOU and DWR based on the pro-rata sharing ordered in CPUC Decision D.02-09-053" – to state the objective that DWR's customers continue to remit power charges to the Department at the CPUC determined remittance rate.

Response: DWR agrees with this clarification and the change is made in this Revenue Requirement.

Summary of Comments of San Diego Gas and Electric

SDG&E Comment #1:
In its comments made on January 17, 2008, SDG&E recommends that DWR set forth the specific factors DWR considered in its evaluation of the amendment and restatement of the Calpine 2 contract.

Response: The available information that is responsive to this comment is contained in information previously provided to the Legislature, PG&E and the CPUC. That information is available for review at the California Energy Resources Scheduling Division (CERS) of DWR, which is located at 3310 El Camino Avenue in Sacramento, California. Any interested party can contact Iryna Kwasny at (916) 574-2009 to arrange to review the materials.

SDG&E Comment #2:
SDG&E recommends that DWR update the Operating Reserve Account to reflect the absence of the Calpine 2 costs.

Response: The Operating Reserve Account is calculated as the greater of (a) the largest aggregate amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any consecutive seven calendar months commencing in such Revenue Requirement Period (b) 12 percent of the Department's projected annual Operating Expenses, provided, however, that the projected amount will not be less than the applicable percentage of Operating Expenses for the most recent 12-month period for which reasonably full and complete Operating Expense information is available, adjusted in accordance with the Indenture to the extent the Department no longer is financially responsible for any particular Power Supply Contract and (c)the Priority Contract Contingency Reserve Amount ("PCCRA") which is the maximum amount projected by the Department to be payable by the Department under and pursuant to Priority Long Term Power Contracts in any calendar month during such Revenue Requirement Period. All projections are to be based on such assumptions as the Department deems to be appropriate after consultation with the Commission and taking into account a range of possible future outcomes (i.e., "Stress Cases").

The Operating Reserve Account Balance for the 2008 Supplemental Revenue Requirement Period is determined by the Department to be $548 million, reflecting an amount equal to the PCCRA. The PCCRA and the most recent 12 month period of Operating Expenses are nearly equal.

SDG&E Comment #3:
SDG&E recommends that DWR incorporate the most recent updated Utility Specific Balancing Account (USBA) in its Final Supplemental Determination.

Response: As has been its practice, the Department provides quarterly actual operating results, USBA balances to the CPUC to assist with the process of allocating its revenue requirements. Preliminary operating results through December 31, 2007 have recently been completed and are incorporated in this Supplemental 2008 Revenue Requirement. The updated USBA information will be provided to the CPUC during their consideration of the Revenue Requirement

SDG&E Comment #4:
SDG&E requested that DWR consider informing affected utilities of its intent to renegotiate terms of similar long-term power contracts; and that DWR maintain neutrality on issues such as the cost allocation methodology that do not affect recovery of DWR's revenue requirement.

Response: This comment is beyond the scope of this 2008 Revenue Requirement determination, but has been brought to the attention of DWR management.

J. ANNOTATED REFERENCE INDEX OF MATERIALS UPON WHICH THE DEPARTMENT RELIED TO MAKE THE DETERMINATION

Volume	Record Number	Date	Record Title
DWR08pRR	001	10/30/06	Revised Determination of Revenue Requirements for 2007, including the Determination, the Notice, and the Transmittal letter to the Commission
DWR08pRR	002	11/09/06	Decision 06-11-003: "Opinion Allocating The Benefits And Costs Of A California Department Of Water Resources Natural Gas Contract".
DWR08pRR	003	11/20/06	SDG&E AL 1845-E (CPUC approved): Request for approval of Renewable Power Purchase Agreements Resulting from the 2005 Renewable Portfolio Standard Solicitation.
DWR08pRR	004	11/20/07	PG&E AL 2936-E: "Contract for 2007 Demand Response and Approval and Recovery of Program Costs; and Revisions to Electric Preliminary Statement Part CP – energy Resource Recovery Account (ERRA)". (Public Version). The CPUC issued the approval letter on March 2, 2007, with an effective date of December 30, 2006.
DWR08pRR	005	11/21/06	"DWR Electric Power Fund Financial Statements for the years ended June 30, 2006 and 2005" posted on November 21, 2006.
DWR08pRR	006	11/30/06	"DWR Electric Power Fund Financial Statements September 2006" posted on November 30, 2006.
DWR08pRR	007	12/04/06	DWR letter to the Commission regarding the ALJ Draft Allocation Decision dated November 14, 2006.

Volume	Record Number	Date	Record Title
DWR08pRR	008	12/14/06	Decision 06-12-035: "Order Allocating The 2007 Revenue Requirement Determination Of The California Department Of Water Resources".
DWR08pRR	009	12/20/06	SDG&E AL 1855-E: "Revisions To The DWR Power Charge And DWR Bond Charge Pursuant To D.06-12-035".
DWR08pRR	010	12/28/06	SCE AL 2080-E: "Implementation of the 2007 DWR Power and Bond Charges in Accordance With Decision 06-12-035".
DWR08pRR	011	12/28/06	PG&E AL 2961-E: "2007 DWR Revenue Requirement Determination".
DWR08pRR	012	01/03/07	CEC 2006 Integrated Energy Policy Report Update adopted on January 3, 2007.
DWR08pRR	013	01/25/07	SCE AL 2080-E: "Substitute Sheets for Advice 2080-E".
DWR08pRR	014	02/09/07	SCE AL 2086-E: Transfer of Performance Test Monitoring from the CDWR to SCE Consistent with the Operating Order between DWR and SCE.
DWR08pRR	015	02/14/07	SCE AS 2080-E: "Substitute Sheets for Advice 2080-E".
DWR08pRR	016	02/22/07	"DWR Electric Power Fund Financial Statements December 31, 2006" posted on February 22, 2007.
DWR08pRR	017	02/28/07	SCE Application For Approval Of Results Of Fast Track Of Its New Generation Request For Offers.
DWR08pRR	018	03/05/07	DWR Memo to CPUC supporting ALJ Draft Decision of 02 13 07 regarding Servicing Agreements.
DWR08pRR	019	03/15/07	Decision 07-03-025: "Opinion Regarding The Request Of The CDWR To Modify The Servicing Orders:.
DWR08pRR	020	04/02/07	SCE ERRA Reasonableness of Operations, 2006 Public Version.
DWR08pRR	021	04/10/07	DWR Data Request 1 to IOUs including Transmittal email, Questions, Load Forecast Form, CEC Energy Facility Status and Hedging Forecast Form.
DWR08pRR	022	04/10/07	Energy Market Simulation Description
DWR08pRR	023	04/24/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** SCE response to DWR Data Request 1.
DWR08pRR	023	05/02/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** PG&E response 1 to DWR Data Request 1.
DWR08pRR	024	05/07/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Record of Coordination: PG&E QF Questions 1.
DWR08pRR	025	05/08/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Record of Coordination: PG&E QF Questions 2.
DWR08pRR	026	05/08/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** SDG&E response 1 to DWR Data Request 1
DWR08pRR	027	05/09/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Record of Coordination: SCE Unit Information.
DWR08pRR	028	05/10/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Record of Coordination: PG&E QF Questions 3.
DWR08pRR	029	05/14/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Record of Coordination: SDG&E DR1 Response

Volume	Record Number	Date	Record Title
DWR08pRR	030	05/15/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Record of Coordination: PG&E Bilateral and QF data.
DWR08pRR	031	05/17/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Record of Coordination: PG&E Bilateral, QF and RMR data.
DWR08pRR	032	06/29/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** PROMOD Base and Stress Case Results For Each Respective IOU
DWR08pRR	033	07/03/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Financial Model CFMG5 Projection of Revenue Requirements For Each Respective IOU
DWR08pRR	034	07/03/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** DWR's Long Range Base and Stress Case Gas Forecast
DWR08pRR	035	07/03/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Long Range Estimate Of General And Administrative Costs
DWR08pRR	036	07/03/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** PROSYM Sales Forecast Inputs To PROMOD
DWR08pRR	037	07/19/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Revenue Requirement Hedging Workpaper
DWR08pRR	038	07/20/07	Review of WECC Market Simulation in the Development of the California Department of Water Resources' Revenue Requirement
DWR08pRR	039	07/20/07	Calpine Plan Of Reorganization: includes Press Release, Plan Of Reorganization, Plan Supplement and Disclosure Statement.
DWR08RR	040	07/20/07	Proposed Determination of Revenue Requirements for the period of January 1, 2008 through December 31, 2008, including the "Notice", the "Regulations" and the Proposed Determination.
DWR08RR	041	08/10/07	PG&E Comments on the DWR Proposed Revenue Requirement Determination for 2008
DWR08RR	042	08/10/07	SCE Comments on the DWR Proposed Revenue Requirement Determination for 2008
DWR08RR	043	08/06/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Record of Coordination: SDG&E comments on the DWR Proposed Revenue Requirement Determination for 2008 including supporting data
DWR08RR	044	08/16/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Record of Coordination: SCE supporting data for comments on the DWR Proposed Revenue Requirement Determination for 2008
DWR08RR	045	08/16/07	Record of Coordination: SFO Peaker update
DWR08RR	046	08/22/08	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** PROMOD and Financial Model data supporting the Determination with individual reports for PG&E, SCE and SDG&E
DWR08RRR	047	10/09/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Gas Hedging Work Paper Update

Volume	Record Number	Date	Record Title
DWR08RRR	048	10/09/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** PG&E comments on resource modeling in DWR Proposed Revenue Requirement Determination for 2008
DWR08RRR	049	10/09/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** SCE comments on resource modeling in the DWR Proposed Revenue Requirement Determination for 2008
DWR08RRR	050		Number Omitted
DWR08RRR	051	10/09/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Record of Coordination: SCE supporting data for comments on the DWR Proposed Revenue Requirement Determination for 2008
DWR08RRR	052	10/09/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** DWR's Fall 2007 Long Term Gas Price Forecast
DWR08RRR	053	10/10/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** PROMOD and Financial Model data supporting the Proposed Revised Determination with individual reports for PG&E, SCE and SDG&E
DWR08RRR	054	08/22/07	Determination of Revenue Requirements for the period of January 1, 2008 through December 31, 2008, including the "Notice" and the Determination.
DWR08RRR	055	08/29/07	ALJ Ruling Setting Prehearing Conference
DWR08RRR	056	09/18/07	ALJ Agenda for 9/19/07 Prehearing Conference
DWR08RRR	057	10/01/07	ALJ Extension of time to file comments on Williams Gas
DWR08RRR	058	10/10/07	Proposed Revised Determination of Revenue Requirements for the period of January 1, 2008 through December 31, 2008, including the "Notice" and the Determination
DWR08PSRR	059	10/31/07	Revised Determination of Revenue Requirements for the period of January 1, 2008 through December 31, 2008, including the "Notice" and the Determination
DWR08RRR	060	11/01/07	MRTU Memo to CPUC from Tim Haines,
DWR08PSRR	061	12/07/2007	Restructured long-term power contract with Calpine Energy Services, L.P formerly referred to as the "Long-Term Commodity Sale" transaction, also known as the "Calpine 2" contract
DWR08PSRR	062	12/20/2007	CPUC Decision allocating the Revised Determination of Revenue Requirements for the period of January 1, 2008 through December 31, 2008
DWR08PSRR	063	12/21/2007	Memo to James Olson pertaining to Operating Reserves
DWR08PSRR	064	12/27/2007	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** PROMOD and Financial Model data supporting the Proposed Supplemental Determination with individual reports for PG&E, SCE and SDG&E
DWR08SRR	065	1/17/2008	Comments from PG&E on Proposed Supplemental 2008 Revenue Requirement
DWR08SRR	066	1/17/2008	Comments from SCE on Proposed Supplemental 2008 Revenue Requirement

Volume	Record Number	Date	Record Title
DWR08SRR	067	1/17/2008	Comments from SDG&E on Proposed Supplemental 2008 Revenue Requirement
DWR08SRR	068	2/14/2008	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Gas Hedging Workpaper Supporting Hedging Projections and Budget
DWR08SRR	069	2/15/2008	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** PROMOD and Financial Model data supporting the Supplemental Determination with individual reports for PG&E, SCE and SDG&E

ATTACHMENT A

STATE OF CALIFORNIA -- THE RESOURCES AGENCY

ARNOLD SCHWARZENEGGER, *Governor*

DEPARTMENT OF WATER RESOURCES
1416 NINTH STREET, P.O. BOX 942836
SACRAMENTO, CA 94236-0001
(916) 653-5791

January 15, 2008

Assemblyman Lloyd Levine, Chair
Committee on Utilities and Commerce
State Capitol, Room 5136
Sacramento, California 95814

Dear Chairman Levine:

Thank you for your letter of December 21, 2007 concerning the Department of Water Resources' (DWR) renegotiation of the Calpine 2 power purchase agreement. I appreciate your interest in DWR's decision to renegotiate the Calpine 2 contract and feel that some background information would be helpful in understanding DWR's past and current roles in California's energy market; why DWR decided to renegotiate the Calpine 2 contract; and how that decision fits into DWR's overall strategy to phase out its energy crisis induced involvement in electricity markets.

Background

During California's 2000-2001 energy crisis, the Governor and the Legislature called upon DWR to purchase power for the State's three Investor-Owned Utilities (IOUs) that were on the brink of insolvency and no longer credit-worthy. DWR created the California Energy Resources Scheduling Division (CERS) to purchase power at a time when illegal market manipulation and gaming activity by suppliers was rampant. The CERS division set up a 24/7 power supply operation that initially bought the majority of the IOU's power needs out of the volatile and dysfunctional spot energy market. The average daily spot market price for energy exceeded $400/MWh at the time. Hourly peak period prices at that time ranged from $300 to over $1,000/MWh. Using General Fund monies, CERS spent between $60 and $100 million per day to keep California's lights on.

To stabilize the energy markets and protect the State's economy, the Legislature enacted Assembly Bill 1 of the 2001-02 First Extraordinary Session (AB 1X). AB1X directed DWR to reduce its exposure to the spot market and assemble a portfolio of power contracts that would provide reliable electric service at the lowest-possible price.

AB 1X prohibited DWR from entering into new contracts after December 31, 2002. By that time, DWR had assembled a portfolio of contracts with 30 counterparties to provide 58 energy contracts at an estimated total cost of $42 billion. These contracts provided approximately 30 percent of the annual energy needs of the three IOUs' customers. The contracts helped stabilize California energy markets by significantly reducing the volumes of energy bought in the spot market and providing a revenue source that helped to finance the construction of over 5,000 megawatts of state-of-the-art natural gas-fired power plants. Today, DWR's portfolio consists of 26 contracts that provide approximately 20 percent of the power for the IOUs' customers at a remaining total cost of $15 billion.

Renegotiation of Contracts

Despite the success of these contracts in stabilizing California's power markets and providing a reliable source of electricity with price certainty, the IOUs, stakeholder and consumer groups such as TURN, and the Bureau of State Audits criticized DWR for buying too much power, at too high a price, and for too long of a period of time. In its December 2001 report[1], the Bureau of State Audits (BSA) recommended that DWR develop a contract renegotiation strategy to achieve a number of goals, including reducing the amount of "must-take" energy from contracts like Calpine 2, and adding more dispatchable capacity to meet peak load. "Must-take" energy is delivered by a supplier to the buyer regardless of whether the buyer can use it all. Dispatchable capacity means that the buyer of electricity under the contract can call upon the supplier to provide a specific amount of electricity when it is needed and economical to do so. BSA's specific findings and recommendations are included as Attachment 1 to this letter.

To date, DWR has renegotiated most of its contracts to address BSA's concerns. As a result of these renegotiations, DWR cut the total cost of its portfolio (including the most recent Calpine 2 renegotiation) by $7.4 billion. Some of the renegotiations took place within the framework of global settlements of State claims seeking refunds on DWR power purchases during the energy crisis. DWR is still involved in proceedings before the Federal Energy Regulatory Commission (FERC) and litigation in federal and State courts to recover $2.7 billion in overcharges on electricity DWR bought during the crisis.

Recovery of DWR Contract Costs from Ratepayers

With the IOUs' resumption of responsibility for procuring energy to meet their customers' demands, the California Public Utilities Commission (CPUC) allocated the DWR contracts among the State's IOUs so the contracts could be managed as part of their individual portfolios. In making its allocation decisions, the CPUC considered the physical location of the generation, if any, associated with each of the contracts, the amount of power DWR had purchased and the amount of power each IOU needed.

1 "California Energy Markets: Pressures Have Eased, but Cost Risks Remain", California State Auditor, Bureau of State Audits, December 2001)

The CPUC's allocation of the DWR contracts among the IOUs was not perfect, especially for contracts like Calpine 1 and 2, which provided large quantities of "must-take" power around the clock. This misfit between the IOU customer's load and the delivery of DWR contract power, combined with significant price differences between the contracts, created equity concerns among the IOUs which arose when the CPUC was trying to determine how the DWR contract costs would be recovered. A cost-follows-contract approach, whereby 100 percent of the contracts' costs would be recovered from the IOU customers receiving the power, would have left some IOU customers paying significantly more for electricity than other IOU customers.

In its decision on how to allocate the DWR contract costs, the CPUC noted that:

> "Since DWR signed contracts for a statewide need, allocating the fixed costs of contracts to utility service territories based upon geographic location does not match how or why those contracts were obtained. It would be arbitrary and unfair for one or more service territories to end up with a disproportionate number of high-priced contracts when DWR was not trying to balance costs among service territories."[2]

The CPUC adopted an allocation methodology that used a cost-follows-contracts approach for the variable "avoidable" contract costs. These costs would only be incurred when it was economical for the IOU to call on the contract. The allocation of the DWR fixed, non-avoidable contract costs, such as the "must-take" energy costs of the Calpine 2 contract, however, was based on a "fairness metric" that spread costs evenly among the IOUs such that no one set of IOU ratepayers was either harmed or subsidized. This resulted in the CPUC adopting the following *permanent* allocation of DWR contract fixed costs: 42.2 percent - PG&E, 47.5 percent - SCE, and 10.3 percent - SDG&E.[3]

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2 Decision 02-12-045, December 17, 2002, California Public Utilities Commission, OPINION ADOPTING INTERIM ALLOCATION OF THE 2003 REVENUE REQUIREMENT OF THE CALIFORNIA DEPARTMENT OF WATER RESOURCES, p. 10

3 Decision 05-06-060 June 30, 2005, California Public Utilities Commission, ORDER GRANTING, IN PART, PETITION FOR MODIFICATION OF DECISION 04-12-014, ON THE PERMANENT ALLOCATION OF THE DEPARTMENT OF WATER RESOURCES' ANNUAL REVENUE REQUIREMENT, p.16

The CPUC treated these non-avoidable contracts costs differently from the avoidable contract costs because the IOUs, ratepayer advocate groups and the CPUC itself regarded them as "above market" and therefore "burdensome" to ratepayers. In their joint filing to the CPUC, PG&E, SCE and TURN stated:

> "The customers of the utilities must take power from DWR, and must bear the costs of that power. To the extent that the costs are equal to the market costs for the power, there is no burden associated with the requirement that customers take DWR's power. It is only to the extent that the costs of the power exceed its market value that a burden is imposed on customers."[4]

The CPUC's method to allocate the DWR non-avoidable contract costs among the IOUs underlies both PG&E's reluctance to assume the unamended Calpine 2 contract when DWR offered it to them and why PG&E likely objected so strongly to the terms of the amended agreement.

Why was the Calpine 2 Contract Amended?

From Spring 2004 until Summer 2007, PG&E, DWR and Calpine worked together to amend the Calpine 2 contract. The goal of these negotiations was to improve the fit of the contract to PG&E's customer load and reduce the amount of surplus Calpine 2 energy that PG&E would have to sell off during low demand hours at a price that was lower than its cost to DWR. Losses on surplus sales are recovered from all three IOUs' customers using the same cost allocation percentages for non-avoidable costs. The CPUC's cost allocation methodology therefore results in an artificially low cost for any single DWR contract and masks the losses an individual IOU sees when it sells off surplus DWR power. Had PG&E been responsible for 100 percent of the cost of Calpine 2 and 100 percent of the losses on surplus sales, there would have been a greater incentive for PG&E to restructure the Calpine 2 contract. The CPUC method for allocating the DWR contracts' fixed-costs among all three IOUs, however, removed any such incentive.

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4 Decision 05-06-060 June 30, 2005, ORDER GRANTING, IN PART, PETITION FOR MODIFICATION OF DECISION 04-12-014, ON THE PERMANENT ALLOCATION OF THE DEPARTMENT OF WATER RESOURCES' ANNUAL REVENUE REQUIREMENT, p. 7

Loss of Cross-Subsidy

Assuming the CPUC leaves the current allocation methodology unchanged, SCE and SDG&E customers will significantly benefit from the changes to Calpine 2 while PG&E will incur the full cost of replacement power. PG&E sees this as a violation of the "fairness metric" the CPUC used when it adopted its permanent methodology for allocating the "burdensome" DWR contract costs. At the time DWR offered the Calpine 2 contract to PG&E, we also offered to work with the CPUC to find an administrative solution to address the cost allocation concerns.

In a December 14, 2007 letter to CPUC President Peevey (Attachment 2) concerning the Calpine 2 amendment and the need for DWR to modify its 2008 revenue requirement, I noted that while the Calpine 2 amendment would provide net savings statewide, these savings would be disproportionately applied unless the contract cost allocation methodology was adjusted. I further requested that upon submission of DWR's Supplemental 2008 Revenue Requirement, the CPUC modify the cost allocation of the DWR contracts to equitably allocate the changes in DWR's total costs resulting from the Calpine 2 amendment.

DWR Role in Statewide Energy Supply

Seven years after the State's energy crisis, DWR continues to play a significant role in meeting statewide demand for electricity. DWR's role in the power market was designed to be temporary, allowing the IOUs sufficient time to regain their financial footing so that they could resume purchasing electricity for their customers. DWR's continued involvement in energy markets on the IOUs' behalf has led to certain inefficiencies, as well as conflicts with other State energy policies.

For example, if the IOUs were to take full legal and financial assignment of the DWR power contracts, they could use their long-term involvement in energy markets as leverage in renegotiating the contracts to:

- retain generation resources—paid for by the DWR contract—at a lower cost compared to new generation; and
- provide a source of revenue for new green resources that need long-term contracts to secure project financing.

DWR's temporary role in providing power limits its ability to renegotiate contracts to bring new renewable energy projects on-line. Developers of new renewable energy projects need long-term contracts in order to get financing for the projects. In the past three years, the CPUC has approved IOU renewable energy contracts of 15-20 years for new wind, solar, geothermal and biomass generation. These are terms well beyond DWR's role in the market.

Having the IOUs take full legal and financial assignment of the DWR contracts would result in a better alignment of incentives for the IOUs to pursue procurement plans that ensure State energy policy goals are met.

Direct Responses

Your letter posed a number of questions regarding the Calpine 2 amendment and DWR's renegotiation process and current renegotiation efforts which are addressed below.

Data request/Preserving the value of the contract (Questions 1, 2, 3)

Attachment 3 to this letter provides a summary of the analysis that we relied on in amending the Calpine 2 contract. More detailed analyses are covered by confidentiality agreements. We are working with the other parties to determine what can be made available.

Why did DWR choose to negotiate a replacement for Calpine 2 after successfully challenging Calpine's attempt to reject the contract?

DWR opposed Calpine's attempts to reject the contract in order to preserve its value for ratepayers. Calpine's plan to exit bankruptcy contemplated paying only pennies on the dollar for the market value of the Calpine 2 contract upon termination or restructuring. DWR's successful litigation preserved the value of the contract. After PG&E declined the opportunity to take over the contract, DWR proceeded with restructuring in order to provide a dispatchable product while maintaining the value of the contract.

Does the Calpine 2 amendment account for the "lost value" of the contract Special Conditions?

Special Condition 3 of the Calpine 2 contract required that Calpine, during periods of high demand, use only its own power generation to deliver the power required by the contract. In other words, it prevented Calpine from going to the spot market to purchase power needed to fulfill its contract requirements for DWR. As a result, Special Condition 3 helped to ensure a more reliable power grid by making certain that Calpine's own resources were committed to producing the power DWR purchased during periods of high demand. The CPUC and the California Independent System Operator (ISO) have now established rules for system reliability, or "Resource Adequacy," as it is known. With the CPUC's 2006 creation of Resource Adequacy obligations, PG&E will replace the Resource Adequacy value in the market as necessary. DWR considered this cost when analyzing the value of the amended Calpine 2 contract.

What process does DWR use in evaluating and renegotiating its contracts?

As discussed previously, the process guiding DWR in evaluating and renegotiating its contracts came from the Bureau of State Audits report's findings and recommendations provided as Attachment 1 to this letter. Attachment 1 also describes the development of DWR's renegotiation goals.

For which contracts is DWR currently engaged in renegotiation discussions?

Attachment 4 contains a list of DWR's remaining contracts. DWR is currently engaged in contract discussions with Sempra Energy and Coral Energy. Also, DWR will have to amend all of its contracts to accommodate changes brought about by the ISO's new Market Redesign and Technology Upgrade (MRTU) scheduled to go live in Spring 2008. We expect these amendments to be technical in nature, specifically related to scheduling and delivery point.

I look forward to working with you and your staff in your review of the Calpine 2 amendment and DWR's role in statewide power supply. Should you have any additional questions, or if you would like to discuss the information provided here, please do not hesitate to contact me at (916) 653-7007, or Tim Haines, Deputy Director of California Energy Resources Scheduling, at (916) 574-2733.

Sincerely,

Lester A. Snow
Director

Attachments

Attachment 1

Findings and Recommendations for the Bureau of State Audit's Report "California Energy Markets: Pressures Have Eased, but Cost Risks Remain" and DWR Contract Renegotiation Goals

The process guiding DWR in evaluating and renegotiating its contracts came out of the Bureau of State Audits' recommendations in its report entitled "California Energy Markets: Pressures Have Eased, but Cost Risks Remain", (December 2001). The report's findings regarding DWR's power portfolio are summarized below:

- The DWR portfolio leaves it exposed to substantial market risk in high peak-demand periods if supply shortages occur and to substantial market risk with surplus contract amounts in other hours of the year.

- Contracts provide ample energy but not sufficient capacity. The portfolio does not contain sufficient power for peak-demand periods, thus potentially exposing consumers to high market prices if energy supply becomes limited during those periods

- The portfolio lacks the flexibility to substantially reduce purchases. Many of the contracts are nondispatchable, meaning that they lack the flexibility to substantially reduce purchases during periods of surplus or low market prices and must pay for the power whether or not it is needed.

- Contract terms and conditions may not ensure reliability. DWR cannot terminate or assess penalties even if the generators repeatedly or deliberately fail to deliver power. The contracts also fail to include provisions to ensure that suppliers follow through with construction of proposed power plants.

- DWR's portfolio emphasizes significant amounts of fixed price energy to limit volatility also limits potential portfolio cost savings if power prices decline. DWR could also have employed more tolling agreements, which would have allowed the contract price to decrease if gas prices decrease.

- DWR's long-term agreements for power supplies do not provide the State with meaningful opportunities to renegotiate terms or to terminate the agreements. In addition, DWR usually cannot reassign power contracts to utilities unless the sellers agree to the transactions.

The Auditor's report recommended that DWR:

- Develop a contract renegotiation strategy, informed by legal and economic reviews, that centers on improving the reliability and the overall balance and performance of the portfolio.

DWR implemented the BSA recommendation, which was the basis for its renegotiation efforts. By Dec. 4, 2001 the CERS Contract Management Group had a draft of its "Renegotiation Objectives and Criteria". By the end of January 2002, a state renegotiation team had been assembled that focused on the following goals:

- Greater ratepayer value (increase pricing flexibility, eliminate fixed pricing, convert to tolling agreements)
- Lower pricing
- Greater dispatch flexibility (eliminate must-take energy and add in more dispatchable capacity)
- Improved performance requirements (Increase performance requirements/penalties for non-performance)_
- Greater reliability (include anti-gaming provisions, reduce market purchases/substitution to provide for plant-specific source of power, add more peaking capacity)
- Add novation provisions to allow DWR to transfer contracts to utilities
- Reduce DWR footprint (shorten terms and volumes of energy – fixed cost reductions)

In 2004, DWR, along with other market participants, raised concerns about how the delivery provisions in their contracts might be interpreted and treated under the ISO's proposed market redesign and technology upgrade (MRTU). These provisions, which were intended for the existing 3-zone congestion management system, would not function properly in MRTU's proposed nodal system. The Federal Energy Regulatory Commission (FERC) established a separate proceeding to address the so-called "seller's choice" problem in California. The issues were resolved through enhancements to the proposed MRTU tariff along with contract modifications. Since that time, DWR's contact renegotiation goals have also included adding provisions necessary to preserve ratepayer value upon implementation of MRTU (currently scheduled for Spring 2008).

Attachment 2

STATE OF CALIFORNIA – THE RESOURCES AGENCY

DEPARTMENT OF WATER RESOURCES

1416 NINTH STREET, P.O. BOX 942836
SACRAMENTO, CA 94236-0001
(916) 653-5791

ARNOLD SCHWARZENEGGER, Governor

December 14, 2007

The Honorable Michael R. Peevey, President
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102

Dear President Peevey:

Consistent with previous discussions between the California Department of Water Resources (DWR) and the California Public Utilities Commission (CPUC), DWR is proceeding with efforts to reduce the State's role in supplying energy statewide. The CPUC has a vital role to play in facilitating the smooth transition of energy crisis-era contracts to the investor owned utilities (IOUs), which can more appropriately respond to today's energy market. Toward that end, DWR is requesting that the CPUC take immediate action to evaluate and adjust the allocation of DWR costs among the IOUs to facilitate this transition.

Our recent amendment to the Calpine 2 contract has significant benefits, but highlights both the general policy issues which must be addressed, as well as the short term need for cost allocation changes. While the Calpine 2 amendment provides net savings to statewide ratepayers, these savings can be disproportionately applied unless the contract cost allocation is adjusted.

Following up on the discussions and consultations between DWR and the CPUC over the past few months, on December 7, 2007, DWR and Calpine executed an amendment modifying the Calpine 2 contract. The amended agreement replaces 1000 MW of 7 x 24 market delivery product with a deeply-discounted 180 MW dispatchable unit-contingent product from the Los Esteros combustion turbine project. This contract restructuring is consistent with the State's objective of reducing its overall power supply obligations on behalf of the retail customers of the three IOUs, recognizing their capability to procure their own power supplies as they have done since DWR and the CPUC transferred procurement of new energy supply requirements back to the IOUs at the end of 2002.

The Calpine amendment will result in a $500 million reduction in DWR's 2008 costs and revenue needs. The amendment will also result in a material change in DWR's energy deliveries to Pacific Gas &Electric customers and in the cost allocation, due to the reduced costs among the customers of the three IOUs as of January 1, 2008, the start date of the amended contract.

DWR will initiate its public process to amend its 2008 Revenue Requirement to reflect the amended Calpine 2 contract. DWR requests that the CPUC, upon submission of DWR's amended 2008 Revenue Requirement, modify the cost allocation of the DWR contracts to equitably allocate the changes in DWR's total costs that will be created by the Calpine 2 contract restructuring.

In the coming years, many DWR power contracts will expire and there will be additional opportunities to restructure existing contracts. DWR and the CPUC will need to work together to ensure a long term approach that equitably serves the utilities and ratepayers during this time of transition.

Sincerely,

Lester A. Snow
Director

cc: Sean Gallagher, Director Energy Division
California Public Utility Commission
505 Van Ness Avenue, Room 4004
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Attachment 3

Summary of DWR Analysis of Calpine 2 Contract Restructuring

Attachment 3 will be forwarded at a later date.

Attachment 4
DWR Remaining Contracts

Contract No.	Contract Name	Category Type	Contract Term End Date	1/1/2008	2/1/2008	7/1/2008	7/1/2009	7/1/2010	7/1/2011	7/1/2012	7/1/2013	7/1/2014	7/1/2015
1	Calpine 1	7x24	12/31/2009	1,000	1,000	1,000	1,000	-	-	-	-	-	-
2	Calpine 2	Dispatch	12/31/2009	180	180	180	180	-	-	-	-		-
3	PacificCorp	Dispatch	6/30/2011	300	300	300	300	300	-	-	-	-	-
4	Calpine 3	Dispatch	7/31/2011	495	-	495	495	495	495	-	-	-	-
5	Wellhead - Fresno	Dispatch	10/31/2011	21	22	22	22	22	22	-	-	-	-
6	Wellhead - Gates	Dispatch	10/31/2011	46	46	46	46	46	46	-	-	-	-
7	Wellhead - Panoche	Dispatch	10/31/2011	50	50	50	50	50	50	-	-	-	-
8	Calpeak - Panoche	Dispatch	12/27/2011	51	51	51	51	51	51	-	-	-	-
9	GWF - Phase I,II	Dispatch	12/31/2011	192	192	192	192	192	192	-	-	-	-
10	CalPeak - Vaca Dixon	Dispatch	1/1/2012	50	50	50	50	50	50	-	-	-	-
11	Coral - Peak	6x16	6/30/2012	750	750	750	750	450	450	-	-	-	-
11	Coral - Base	7x24	6/30/2012	100	100	100	100	100	100		-	-	-
9	GWF - Phase III	Dispatch	10/31/2012	169	169	169	169	169	169	169	-	-	-
12	Kings River Conservation District	Dispatch	9/17/2015	97	97	97	97	97	97	97	97	97	97
13	San Francisco Peakers	Dispatch	TBD	-	-	-	192	192	192	192	192	192	192
			PG&E Totals	3,501	3,007	3,532	3,724	2,244	1,944	488	289	289	289
14	Colton - Drews	Dispatch	12/31/2010		-	40	40	40	-	-	-	-	-
14	Colton - Century	Dispatch	12/31/2010		-	40	40	40	-	-	-	-	-
15	Bear Energy AL1,AL5,AL6	Dispatch	12/31/2010	655	655	655	655	655	-	-	-	-	-
15	Bear Energy HB1	Dispatch	12/31/2010	215	215	215	215	215	-	-	-	-	-
15	Bear Energy RB6	Dispatch	12/31/2010	175	175	175	175	175					
16	High Desert	Dispatch	1/21/2011	840	825	730	730	730	-	-	-	-	-
17	Sempra - Base	7x24	9/30/2011	1,200	1,200	1,200	1,200	1,200	1,200	-	-	-	-
17	Sempra - Peak	6x16	9/30/2011	400	400	400	400	400	400	-	-	-	-
18	Mountain View (Wind)	Renewable	9/30/2011	67	67	67	67	67	67	-	-	-	-
19	Allegheny	7x24	12/31/2011	800	800	800	800	800	800	-	-	-	-
			SCE Totals	4,352	4,337	4,322	4,322	4,322	2,467	-	-		-
20	Bear Energy A	7x24	12/31/2007	-	-	-	-	-	-	-	-	-	-
20	Bear Energy B	6x16	12/31/2010	275	275	275	275	275	-	-	-	-	-
20	Bear Energy C	6x16	12/31/2010	50	50	50	50	50	-	-	-	-	-
21	Calpeak - Border	Dispatch	10/23/2011	52	52	52	52	52	52	-	-	-	-
22	Calpeak - Escondido	Dispatch	12/8/2011	53	53	53	53	53	53	-	-	-	-
23	Calpeak - El Cajon	Dispatch	1/1/2012	52	52	52	52	52	52	-	-	-	-
24	Sunrise	Dispatch	6/30/2012	575	575	575	575	575	575	-	-	-	-
25	Whitewater Cabazon (Wind)	Renewable	12/31/2013	43	43	43	43	43	43	43	43	-	-
26	Whitewater Hill (Wind)	Renewable	12/31/2013	62	62	62	62	62	62	62	62	-	-
			SDG&E Totals	1,161	1,161	1,161	1,161	1,161	836	104	104	-	-
			Grand Total	9,014	8,505	9,015	9,207	7,727	5,247	592	393	289	289

26 Total CERS Contracts

Notes:

STATE OF CALIFORNIA -- THE RESOURCES AGENCY

ARNOLD SCHWARZENEGGER, *Governor*

DEPARTMENT OF WATER RESOURCES
1416 NINTH STREET, P.O. BOX 942836
SACRAMENTO, CA 94236-0001
(916) 653-5791

February 7, 2008

Assemblyman Lloyd Levine, Chair
Committee on Utilities and Commerce
State Capitol, Room 5136
Sacramento, CA 95814

Dear Chairman Levine:

This letter transmits documents responsive to the Committee's questions raised during the January 22, 2008 hearing and to your prior request for certain documentation. I appreciate your and the Committee's patience in this matter. Included please find:

Exhibit 1: This attachment provides a comparison of the discounted capacity payment DWR pays under the Calpine amendment for ownership rights to the Los Esteros peak power plant to capacity payments for similar plants. The binder labeled "Peaker Benchmark Documents" was assembled in early 2007 by DWR consultants and staff and is the basis for establishing the market value of the capacity provided under the Calpine 2 amendment.

Exhibit 2: The binder labeled "Calpine 2 Documentation" is Exhibit 2. It includes copies of analyses, analytical data and assumptions DWR relied on prior to signing the amended contract.

Exhibit 3: This attachment provides a matrix that reconciles the economic analysis of the Calpine amendment by DWR and PG&E/TURN.

Exhibit 4: This attachment provides additional information and clarification that was requested during the January 22 hearing.

Should you have any additional questions, or if you would like to discuss the information provided herein, please do not hesitate to contact me at (916) 653-7007, or Tim Haines, Deputy Director of California Energy Resources Scheduling, at (916) 574-2733.

Sincerely,

Lester A. Snow
Director

Attachments

EXHIBIT 1
COMPARISON OF PEAKER PAYMENTS

Following is a description of each item contained in the attached chart labeled "Comparison of Peaker Payments." The values in the chart are actual and projected payments for the type of product DWR purchased in the Calpine 2 amendment and were used to estimate the market value of the peaking capacity in the Calpine 2 amendment. The difference between the estimated market value of the peaking capacity in the amendment and the price DWR actually pays represents the discount that captures the under-market value of the original contract.

DWR Portfolio: This is the range of payments, $80/kW-year to $216/kW-year, for dispatchable peaking power that DWR has made, or currently makes, for dispatchable peak power capacity in its portfolio. The $80/kW-year capacity payment is for a dispatchable 97 MW peaker plant located in Fresno County and operated by the Kings River Conservation District (KRCD). KRCD received two combustion turbines as part of the states' settlement of market manipulation charges against Williams Energy in 2002. The $80/kW-year figure therefore does not include the capital costs of the combustion turbines. The $216/kW-year was for dispatchable peaking capacity from the Los Esteros plant under Calpine 4, which expired in March 2006.

KRCD (Scaled to Bay Area): The next figure on the chart of $160/kW-year is what the capacity payment would be for the KRCD plant if it were constructed in the Bay Area and includes the capital costs of the combustion turbines. As would be expected, the cost of constructing a power plant in the Bay Area would be more expensive than in Fresno County largely because of the cost of land and the cost of obtaining air pollution emission offsets. Unlike a plant built by a utility or merchant generator like Calpine, these costs also reflect municipal financing costs and do not include a return on investment by the owner.

CEC Bay Area Estimate: The cost range of between $173.81 and $197.09/kW-year is derived from the California Energy Commission's (CEC) Generation Cost Model and is for dispatchable peaking capacity located in the Bay Area. The CEC developed this model to provide levelized central station electricity generation costs for their 2007 Integrated Energy Policy Report. The lower value represents the cost to a utility of building a peaker plant. The upper value is the cost to a merchant generator like Calpine.

CCSF Proposed Reference: The $192/kW-yr is an estimate of the cost of installing LM6000 peakers in New York City. This was used as a reference for the cost to construct a peaking power plant in San Francisco.

CCSF Cost: In early 2007 the capacity payment to recover the construction cost of peakers by City and County of San Francisco (CCSF) was estimated at $300/kW-year. The effective capacity payment would equal $360/kW-year when the $80 million for the

value of the turbines and development funds provided to CCSF under the Williams settlement were included.

Total Payments Towards Peakers: The final agreed to capacity payment that DWR would make to CCSF was $171/kW-year, or an effective total payment $231/kW-year.

SCE Peakers: The capacity payment of $218/kW-year is for the four peakers Southern California Edison recently completed. The cost estimate is set forth in the January 9, 2007 filing by Independent Energy Producers in FERC proceeding EL08-20-000.

Calpine 2: The payment DWR makes to Calpine under the amended Calpine 2 contract. This $24/kW-yr

Comparison of Peaker Payments

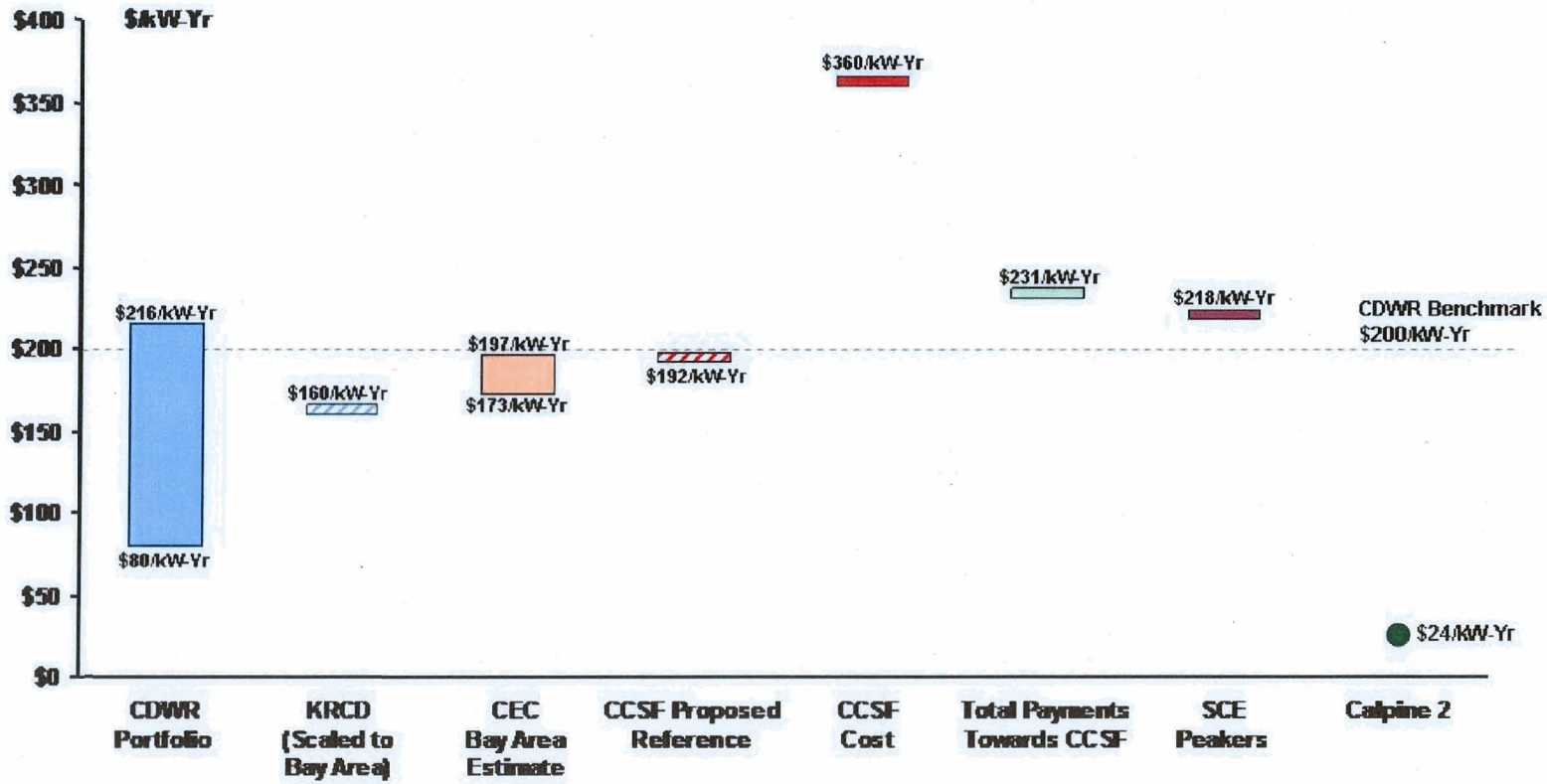

EXHIBIT 2
DWR ANALAYSIS OF CALPINE 2 AMENDMENT
(See "Calpine 2 Documentation" binder)

EXHIBIT 3
Reconciliation of DWR and PG&E/TURN Analysis of Calpine 2 Amendment

	DWR	PG&E and TURN	Difference
Net Capacity Value - Amended Contract	$200/kW-yr, for 5 years less $24/kW-yr amended contract cost	$35/kW-yr for 5 years, less $24/kW-yr amended contract cost	DWR value is based on similar purchases. PG&E and TURN value is based on a "reliability" product.
	$158 M	**$10 M**	**-$148 M**
Resource Adequacy Value - Prior Contract Terms	$21.6/kW-yr	$6.1/kW-yr	DWR value based on PG&E stated value in recent PG&E bid solicitation. PG&E value based on recent purchases.
	-$43 M	**-$12 M**	**$31 M**
Surplus Sales - Prior Contract Terms	4,760 GWh @ $50/MWh	129 GWh @ $46/MWh	DWR assumes prior Calpine 2 contributed to surplus sales. PG&E attributes negligible surplus sales to Calpine 2.
	-$238 M	**-$12 M**	**$226 M**
Replacement Energy - Amended Contract	12,780 GWh @ $68/MWh	17,262 GWh @$67/MWh	DWR assumes prior Calpine 2 contributed to surplus sales, reducing required replacement energy. PG&E assumes nearly all of prior Calpine 2 energy needs replacing.
	$-847 M	**-$1,155 M**	**-$308 M**
Contract Cost – Prior Contract Terms	17,520 GWh @ $59.60/MWh	17,520 @$59.60/MWh	Prior Calpine 2 contract price times fixed energy volume for 2008-09
	$1,046 M	**$1,046 M**	**$0**
Total Value	**$76 M**	**-$123 M**	**-$199 M**

RECONCILIATION OF DWR AND PG&E/TURN ANALYSIS POSITIONS ON CALPINE 2 CONTRACT AMENDMENT

The following provides an explanation of each of the differences between the Department of Water Resources (Department) and the Pacific Gas & Electric (PG&E) and The Utility Reform Network (TURN) assessments of the value of the amended Calpine 2 contract. The attached Table 1 provides a summary matrix of the key factors which determine the value of the modified contract and the assumptions used by each of the parties.

Net Contract Capacity Value – Amended Contract
Under the amendment, DWR pays a price that is $24 per kW per year. The analysis provided in Exhibit 1 ascribes a value of $200/kW-yr for the capacity DWR purchased in the amendment. That net value of $176/kW-yr times 180,000 kW (180 MW) of capacity equals $31.7 million/yr, or $158 million for the 5 year contract rights to the power plant. PG&E and TURN ascribe a value of about $10 million to the capacity.

The differences between DWR and PG&E/TURN assigned value are due to three factors. They are:

1. The level of payment a generator is entitled,
2. Different assumptions regarding the product that DWR acquired in the amended contract and
3. Whether a 4 year old state-of-the-art power plant should be assigned the same value as an identical new power plant.

<u>Generator Payment</u> - In our attempt to reconcile the DWR assumptions with those of PG&E/TURN, we find that there is a wide range of views of how much to pay generators. This is reflective of the policy discussion and disputes taking place at the CPUC, CAISO and FERC. For instance, the CPUC has implemented its Resource Adequacy Requirement to load serving entities. The effect of the requirement is generators receiving a Resource Adequacy payment of up to $40/kW-yr (the value TURN relies on in its analysis of the amendment). However, in a related proceeding at FERC, on November 9, 2007 the Independent Energy Producers filed for increasing the capacity payment to $162/kW-yr. The IEP justified this on the cost of owning a power plant. In another related process, the ISO has also been conducting a stakeholder process that will establish generator capacity payments. There is just as wide a disparity in views regarding the appropriate payment a generator should receive in the CAISO process.

CERS is not party to those proceedings and has not developed a position on this policy discussion. Please see CPUC Rulemaking R.06-02-013 and FERC docket EL08-20-000 for the wide ranging views of the parties to those proceedings. Additionally, you may consider contacting parties to this proceeding for more information.

Product - Another difference between DWR and PG&E/TURN is in regard to the product DWR purchased from Calpine. In the amendment DWR acquired the full rights to all operational capability of the Los Esteros peaking plant. The Exhibit 1 benchmarking analysis is of that type of product. PG&E/TURN analysis assumes a product that only meets the CPUC imposed resource adequacy (RA) requirements. The resource adequacy capacity is intended to satisfy the requirement that load serving entities, like PG&E, have at least 15% planning reserve. The PG&E/TURN assessment does not include any value for the operational rights that DWR acquired in the amendment.

Existing vs. New - In making its decision to amend the Calpine 2 contract, DWR considered the value of a state-of-the-art, recently completed generating plant capacity based on the cost to complete similar generating facilities and the price of contracts for similar operating capability. DWR has assumed that capacity value for recently completed, state-of-the art peaking capacity has a value very near that of the cost to construct new generation of a similar type. This wide difference in value ($158 million of capacity value compared to $10 million of capacity value) stems from a completely different perspective on the value of capacity. PG&E and TURN take the position that owners of existing generating plants should receive payments for capacity at prices which do not even cover their cost of fixed operation and maintenance, let alone cost for their capital investment. This difference in assumptions is the basis of the wide difference in value. Placed in a commercial building metaphor – the PG&E/TURN position is that an office building under construction should lease for $3.00 per square foot/month to cover costs and the owner's return on equity, but a 4 year old nearly identical building next door should lease for $0.50 per square foot because the owner has invested its money and should not expect to recover any of its fixed costs.

Resource Adequacy Value Foregone From Prior Calpine 2 Contract

The original Calpine 2 contract was granted resource adequacy credit to PG&E for the 1000 MW of around the clock energy provided by the contract. In the amendment DWR purchases 180 MW of power. Both parties use the 820 MW difference in their analysis of foregone Resource Adequacy value under the amendment. DWR used PG&E's $21.60/kW-yr resource adequacy value referenced in PG&E's most recent solicitation for resource adequacy contracts. PG&E/TURN used PG&E's stated value of $6.1/kW-yr in responses to its procurement process. This results in a foregone resource adequacy value of $43 million using the Department's assumptions (1000 MW times $21,600 per MW per year times 2 years) and $12 million in foregone resource adequacy value using the PG&E/TURN assumptions (1000 MW times $6,100/MW per year times 2 years).

Surplus Sales Value Foregone From Prior Calpine 2 Contract

The Department and PG&E/TURN have different positions on how much of the prior Calpine 2 around the clock energy of the 1000 MW contract would have been surplus to the needs of PG&E customers. The Department relied upon PG&E's historic surplus sales, plus PG&E's May 2007 estimate provided to the Department that it would have 2,380 GWH of surplus energy sales. PG&E/TURN assumed that despite 2,380 GWH (gigawatthours or thousand megawatt hours) of energy being estimated to be surplus,

only a minor 129 GWH would be surplus to PG&E's needs. PG&E assumed the rest of the 2,380 GWH of surplus sales are "opportunistic" sales into the market where power resources which either PG&E or the Department has available can be sold into the market at prices above the cost to buy or produce that energy.

This assumption by PG&E is counter to historical surplus sales by PG&E. For 2004 through 2006, PG&E sold an average of about 6,000 GWH of surplus energy annually at an average price of less than $50/MWH. The Calpine 2 contract price is $59.60/MWH. Therefore, PG&E historically has sold more than twice as much energy as estimated by PG&E in May 2007, and at an average loss compared to the prior Calpine 2 contract cost.

Based on these different assumptions, the Department assumes that PG&E would have received $238 million for selling surplus energy from the prior Calpine 2 contract, for the remaining two years of the contract (2,380 GWH/yr times $50/MWH times 2 years). PG&E/TURN assumes that PG&E would have foregone only $12 million in surplus sales revenue by not having the prior Calpine 2 contract (129 GWH/yr times $46/MWH times 2 years).

Replacement Energy Cost for the Amended Calpine 2 Contract

To the extent that the prior Calpine 2 contract energy was needed to meet PG&E customer needs, PG&E would need to replace that energy from the market when the 1000 MW of around the clock energy from the prior Calpine 2 contract is no longer available for 2008 and 2009. The Department assumed that of the 2,380 GWH per year of surplus sales projected by PG&E in May 2007, as explained above would be avoided if the prior Calpine 2 "must-take" around the clock energy was no longer supplied. Therefore, the Department assumed that PG&E would need to replace that part of the prior Calpine 2 energy that is not surplus to PG&E customer needs. The prior Calpine 2 contract provided 8,760 GWH of energy annually. The replacement energy would then be 12,780 GWH (8,760 GWH total Calpine 2 supply, less 2,380 GWH of assumed surplus sales/yr, times 2 years[1]). This energy was assumed to be replaced at an average market price of $68/MWH based on market quotes for energy purchases in 2008 and 2009, for a total replacement energy cost of $847 million.

PG&E/TURN assumed that nearly all of the prior Calpine 2 energy - all but the 129 GWH of assumed Calpine 2 energy - would be needed to meet the requirements of PG&E customers as explained in the prior section of this summary. The PG&E analysis assumes 17,262 GWH of energy (8,760 GWH minus 129 GWH or 8,631 GWH per year times 2 years) would need to be replaced at an average cost of $67/MWH, for a total cost of $1,155 million ($1.16 billion).

This difference in assumed replacement energy costs is directly related to the prior explanation of the difference in the assumed amount of the prior Calpine 2 energy supply that was assumed to be surplus to PG&E customer needs.

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[1] Adjusted slightly for 2008 being a leap year with an extra 24 hours.

Contract Cost – Prior Contract Terms
There is one area where the Department, PG&E and TURN agree. The prior Calpine 2 contract would have resulted in the Department purchasing 1000 MW, 8760 hours per year for 2008 and 2009 at the $59.60/MWH contract price. This would have resulted in a total remaining contract cost of $1,046 million which will now not be paid due to the amendment of the Calpine 2 contract.

Resulting Total Difference
The attached matrix shows the result effect of these different assumptions where positive values of the 180 MW of capacity of the amended Calpine 2 contract, less the foregone value of (a) resource adequacy provided by the 1000 MW of the prior Calpine 2, (b) foregone surplus energy sales from the prior Calpine 2, and (c) replacement energy costs required of PG&E to meet its customer energy needs, plus the elimination of the remaining two years of cost of the prior Calpine 2 contract results in an estimated savings of $76 million using the Department's assumptions and $123 million increase in costs using the PG&E/TURN assumptions, or a difference in $199 million in assumed cumulative difference.

EXHIBIT 4
FOLLOW-UP TO REQUESTS FOR ADDITIONAL INFORMATION
AND
REQUESTS FOR CLARIFICATION MADE AT THE JANUARY 22, 2008 HEARING

1. Costs DWR incurred for services provided by outside consultants and law firms associated with the Calpine bankruptcy.

2. Explanation of how the Calpine 2 amendment achieved DWR's renegotiation goals.

3. Clarification of the difference between DWR and PG&E's estimate of surplus sales from the original Calpine 2 contract.

4. Clarification of statement that Calpine 2's special condition 3 did not contribute to grid reliability.

5. Attachment 3 from the January 15, 2008 DWR response to Committee questions. "SUMMARY OF DWR ANALYSIS OF CALPINE 2 CONTRACT AMENDMENT"

Calpine Bankruptcy Estimate

December 2005 thru August 2007

Estimate of the costs DWR incurred for services provided by outside consultants and law firms associated with the Calpine bankruptcy.

Attorney General Office	$40,737.00
Bingham McCutchen	$21,900.00
Brattle Group - Expert	$365,891.22
Luskin Stern & Eisler	$169,061.27
Navigant Consulting	$165,000.00
Pierce Atwood	$1,500,000.00
Platts - Historical Data	$550.00
	$2,262,589.49

Achieving DWR Renegotiation Goals
In Amendments to Calpine 2

	2002 Amendment	Seller's Choice Amendment April 2005	2007 Amendment
Greater customer value	√		√
Lower pricing	√		*
Greater dispatch flexibility	√		√
Improved performance requirements	√		
Greater reliability	√		√
Novation	√		
Reduce DWR footprint	√		√
Comport with CAISO MRTU		√	
Facilitate smooth transition to utilities			√

*NA - different product

"Goals and Objectives"	Assessment of 2007 Calpine 2 Amendment
Greater customer value	The amended contract retains the market value of the original contract and provides an estimated $75 million in net ratepayer savings
Greater dispatch flexibility	The amended contract replaces must-take, round-the-clock energy with dispatchable capacity capable of producing only the energy actually needed.
Greater Reliability	The amended contract (i) provides an identifiable source of generation capacity capable of supplying power during peak demand periods; (ii) contributes to maintaining local reliability needs in the San Francisco Bay Area as opposed to less valuable system reliability provided by the original contract; and (iii) provides operating reserves necessary to maintain grid reliability. The original contract permitted power deliveries from cheaper market sources and only required Calpine to deliver power from its western generation assets when market prices increased.
Reduce DWR footprint	The amended contract eliminates all remaining energy purchase obligations under the final two years of the original contract.
Facilitate smooth transition to utilities	The IOUs have concerns that taking assignment of the DWR contracts will impact their credit ratings and that there is no guarantee the CPUC will grant full cost recovery for the contracts. The annual fixed cost of the contract is reduced from $522 million to $4.5 million. The lower debt obligation of the amended contract makes it easier for PG&E to take assignment. The amended contract also provides a product that is significantly below market value making it easier for the CPUC to allow full cost recovery in PG&E's rates.

Surplus Sales Volumes

At the January 22nd Committee meeting, there was some confusion regarding the volumes of surplus energy that DWR had attributed to the original Calpine 2 contract. The estimate of surplus sale was used to determine the market value of the original contract, the replacement energy cost to PG&E and the determination of net ratepayer benefit from the amended Calpine 2 contract.

In May 2007, PG&E provided DWR an estimate of surplus energy sales of 2,380 gigawatt hours (GWh) for 2008 as part of PG&E's input to the Department's 2008 revenue requirement determination. The original Calpine 2 contract provided 1,000 megawatts (MW) of energy in every hour of the year for an annual total of 8,760 GWh. In its determination of the economic benefits of the Calpine 2 amendment the Department used PG&E's forecast of surplus sales and assumed that elimination of the 1,000 MW of "must-take" energy would eliminate all of those surplus sales. The estimate that DWR provided in the hearing that 27% of the Calpine 2 energy was being sold as surplus energy was derived by dividing PG&E's surplus sales estimate of 2,380 GWh by the 8,760 GWh of annual energy from the original Calpine 2.

PG&E subsequently has stated that its surplus sales projections are primarily economic sales from power plants and contract deliveries to which it has rights, and that only 129 GWh of surplus sales are from surplus "must-take" energy supply contracts like Calpine 2. Dividing 129 GWh by 8,760 GWh results in the PG&E estimate that only 1.5% of the annual energy from Calpine 2 was being sold as surplus energy.

DWR used PG&E's May 2007 estimate of surplus sales based largely on historical annual surplus sales PG&E has made which have been at levels of approximately 6,000 GWh at an average price of less than $50 per MW-hour (MWh). The $50/MWh price is well below the market price for power in peak demand hours and is nearly $10/MWh below the original Calpine 2 contract price. This historic trend provides the analytical basis for DWR assumption that PG&E's surplus sales of energy were not economic market sales and were in fact in excess of PG&E's needs.

Calpine 2's Contribution to Grid Reliability

At the Committee hearing DWR stated the original Calpine 2 contract special condition 3 no longer contributed to grid reliability. The original Calpine 2 contract special condition 3 required that Calpine provide energy from its generating resources in California and the western region to satisfy the requirements of the contract during periods when the California ISO determined there is a risk of inadequate power supply reserves to support grid reliability. The value of this contract provision's contribution to grid reliability was reduced by 2007, when PG&E and the other two investor-owned utilities completed the first two years of CPUC mandated "resource adequacy" procurements. Beginning in the summer of 2006, the CPUC required utilities to meet a planning reserve margin target of 15% in every month to ensure grid reliability. PG&E's procurements in 2006 and 2007 to meet these CPUC-mandated resource adequacy

requirements rendered the special conditions of the prior Calpine 2 contract terms requiring Calpine to operate its generation plants during grid emergencies far less important going forward.

ATTACHMENT 3
SUMMARY OF DWR ANALYSIS OF
CALPINE 2 CONTRACT AMENDMENT

This summary explains the analyses with respect to ratepayer cost impacts that DWR undertook and considered as part of its decision to amend the Calpine 2 contract. The first part of this analysis looks at whether the amended Calpine 2 contract captured the under market value of the original Calpine 2 contract. The second part of the analysis looks at the replacement cost of energy for PG&E.

Under Market Value of the Original Calpine 2 - The original Calpine 2 contract provided 1,000 megawatts (MW) of electricity 24 hours-a-day 7-days-a-week at a fixed price of $59.60 per hour producing 8.8 million megawatt hours of electricity at an annual cost of approximately $520 million for a total remaining contract cost of $1.046 billion. In restructuring the contract, DWR sought to retain the under-market value of the electricity from the original contract. The under-market value equals the difference between the fixed-price for energy under the contract —$59.60 per megawatt hour— and the and market prices for electricity for the remainder of the original contract term that was projected at the time the analysis was made. The original Calpine 2 contract ran through the end of 2009.

Market Value of Original Calpine 2 Contract – DWR's consultant calculated the market value of the electricity from the original contract for the years 2008 and 2009 using prices projected for electricity in Northern California as quoted on the New York Mercantile Exchange (NYMEX) for 2008 and 2009. The prices were projected in mid-October, 2007around the time when DWR believed a deal for amending the contract would come together. This forecast of "forward" electricity prices produced an expected market value of Calpine 2 energy of $1,204 million. The difference between the market value of Calpine 2 energy and the DWR contract cost for that energy represents the under market value that would have to be captured in the amended contract.

Market Value of Original Calpine 2 Contract	$1,204 million
- Less DWR Contract Cost	$1,046 million
Under Market Value of Original Calpine 2 contract	$158 million

Amended Calpine 2 - The amended Calpine 2 contract provides a 180 MW of generation capacity from the Calpine Los Esteros plant located in the Silicon Valley.[2] The Los Esteros plant is a quick-start generation facility that can come on-line quickly to provide electricity during high demand periods or operating reserves[3] or as needed to

[2] At the time it was built, the CAISO identified the San Jose area as being among the most generation-deficient and the.Los Esteros plant as being critical to supporting Silicon Valley's power needs.

[3] The California Independent System Operator's (CAISO's) procures operating reserves to provide electricity if there is an unexpected outage of a transmission line or power plant.

maintain grid reliability. The amended contract is for a period of at least two years, and provides an option for an additional three.

Market Value of Los Esteros Capacity – The amended contract captures the market value of the original Calpine 2 contract by providing DWR with "ownership-like" rights to a power plant PG&E can use to meet peak demand loads, at a highly discounted price. The amended contract requires DWR to pay Calpine $4.3 million annually. The $4.3 million is referred to as a capacity payment, which is essentially the "rental payment" for ownership like rights to the plant. Under the amended contract Calpine charges DWR $24 per kilowatt of capacity for each year during the term ($24,000 per megawatt-year). The total DWR cost of capacity under the amended Calpine 2 over 5 years is $21.6 million.

DWR Cost of Los Esteros Capacity = 5 yrs x 180 MW x $24,000-per MW = $21.6 million

DWR based the market value of the Los Esteros capacity on recent transactions for the purchase of capacity, some of which are public and others which are confidential. DWR assessed the market value the Los Esteros capacity at $36 million annually using a capacity value at $200 per kilowatt-year of capacity.[4]

Market Cost of Los Esteros Capacity = 5 yrs x 180 MW x $200,000 per MW = $180 million.

The difference between the DWR cost for Los Esteros Capacity and the market value provides the under market value of the amended contract.

Market Cost of Los Esteros Capacity	$180.0 million
- Less DWR Cost of Los Esteros Capacity	$21.6 million
Under-market value of the amended Calpine 2	$158.4 million

Therefore the under-market value of the amended Calpine 2 contract is approximately equal to the under-market value of the original Calpine 2 contract. The under-market value also assumes that all the energy provided under the original contract was being used to meet PG&E customer needs.

PG&E's Replacement Cost of Energy - The next step in the analysis was to determine PG&E's replacement cost of energy. The amount of replacement energy PG&E needs was determined by making an assumption about the amount of the original Calpine 2 energy that would have been sold as surplus energy into the

[4] This value is consistent with estimates that DWR determined when evaluating the City and County of San Francisco peaking plant that is under contract with DWR for future development. DWR also paid an average of $216/kW-yr for the Los Esteros plant capacity during the term of its prior separate contract with Calpine that expired in 2006. The $200/kW-yr price is also consistent with the effective cost of peaking generation installed by Southern California Edison in 2007.

wholesale market. The assumption about surplus sales was derived from confidential information provided by PG&E regarding surplus sales.[5]

2008-2009 Period Energy Volumes (GWH)

Surplus Sales Energy	Replacement Energy	Total
4,758	12,786	17,544

The cost of replacement energy was valued using the NYMEX forward electricity prices described above. The value assigned to surplus sales energy was $50/MWH, which is the average price that PG&E had received for its surplus energy sales in 2007.

The table below summarizes the resultant replacement cost of energy for the two cases for the remaining two years (2008-09) of the original Calpine 2 contract, plus the value of surplus energy sales that could have been made from the Calpine 2 energy under the original contract.

Summary of Replacement Calpine 2 Energy Costs and Surplus Sales ($millions)

Cost to replace prior Calpine 2 energy estimated to be required by PG&E customers	$847
Plus foregone value of estimated surplus prior Calpine 2 energy that would have been sold wholesale[6]	$238
Total replacement cost and foregone surplus energy sales of original Calpine 2 contract	$1,085

The result of both cases show that the replacement cost of the energy plus the lost value of surplus sales is comparable to the cost of the original Calpine contract.

Net Value of the Amended Contract – To determine whether there is a net savings as a result of the amended contract, the replacement cost of energy plus the value of foregone surplus sales, has to be adjusted to account for the "resource adequacy" value of the original contract and the market value of the amended contract.

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[5] From 2004 through 2006, PG&E sold an average of 6 million megawatt-hours (6,000 gigawatt hours, or GWH) of surplus energy into the wholesale market. PG&E has informed DWR that it expects to continue selling surplus energy into the wholesale market in 2008 and 2009, but has only provided estimates of surplus sales for 2008

[6] Estimated sales that are surplus to the needs of PG&E customers, sold in the wholesale market if Calpine 2 remained unchanged

The CPUC credits the DWR contracts with so-called "Resource Adequacy" (RA) capacity value, which is the value of having generating capacity available to meet customer demands.[7] The 1,000 MW's of the original Calpine 2 contract had an RA value of $22 million annually ($22 per kilowatt of capacity). For 2008 and 2009 the total RA value was $44 million.

RA capacity value is not the same as the capacity value of the amended contract. There is no entitlement to energy or opportunity to bid the capacity into the CAISO markets. The amended contract provides full operating rights to the Los Esteros plant.

Making the adjustments for RA value and the market value of the amended contract below results in a net savings to ratepayers of $75 million.

	($ million)
Original Calpine 2 Replacement Energy + Foregone Surplus Sales Revenue	1,085
Plus the Resource Adequacy (capacity value) of original Calpine 2 contract	44
Less Original Calpine 2 Contract Cost for 2008-09 no longer funded by DWR	-1,046
Less 5-yr Capacity Value of the 180 MW from amended Calpine 2	-180
Plus the Contract Price for the amended Calpine 2 contract	22
Total Net Savings of Amended Calpine 2	**$75**

[7] The definition of resource adequacy is "the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements (e.g. substations, transmission lines, power plants).