State of California

Department of Water Resources

Proposed

Determination of Revenue Requirements

For the Period

January 1, 2008, Through December 31, 2008

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

July 20, 2007

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A. THE PROPOSED 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 Determination of Revenue Requirements for the period January 1, 2008, through December 31, 2008 (the "Proposed 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 Proposed Determination.

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

This Proposed 2008 Determination takes into account preliminary actual operating results of the Department through April 30, 2007 and projected operating results through the end of 2007.

[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.

For the 2008 Revenue Requirement Period, this Proposed 2008 Determination contains information regarding the following[2]: (a) the projected beginning balance of funds on deposit in the Electric Power Fund (the "Fund"), including the amounts projected to be 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 meet the Department's Costs, including all Retail Revenue Requirements.

PROPOSED DETERMINATION OF REVENUE REQUIREMENTS

Pursuant to the Act, the Rate Agreement and the Regulations, the Department hereby proposes to determine, on the basis of the materials presented and referred to by this Proposed 2008 Determination (including the materials referenced in Section I), that its cash basis revenue requirement for 2008 is $4.915 billion, consisting of $4.081 billion in Power Charges and $0.834 billion in Bond Charges..

As previously noted, this 2008 Proposed Determination takes into account preliminary actual operating results through April 30, 2007 and projected operating results through the remainder of the 2007 Revenue Requirement Period. Actual costs expended and revenues received by the Department during the 2007 Revenue Requirement Period will directly affect the Department's beginning account balances for the 2008 Revenue Requirement Period. To the extent that actual expenses and revenues differ from those projected in the Department's Final 2007 Determination of Revenue Requirements for the period January 1, 2007 through December 31, 2007, published October 30, 2006 (the "Final" 2007 Determination"), the Department's beginning account balances for the 2008 Revenue Requirement Period will also differ from those projected in the Final 2007 Determination.

Any net surpluses collected during the 2007 Revenue Requirement Period, which may result from the receipt of funds related to various litigation settlements involving the Department, lower actual natural gas prices than those forecast and other considerations, are projected to offset costs incurred by the Department in 2008. Potential sources of operating surpluses are addressed within Section D and Section E of this Proposed Determination. The Department intends to update its projections for this 2008 Proposed Determination, based on actual operating results through mid-summer 2007, later this year.

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 final 2007 Determination.

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.

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[2] Where appropriate, the Department has provided information in this Proposed 2008 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 Proposed 2008 Determination, quantitative statistics presented in tabular form may not add due to rounding.

TABLE A-1
SUMMARY OF THE DEPARTMENT'S PROPOSED 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	1,018	1,063	(44)
3	Priority Contract Account	-	-	-
4	Operating Reserve Account	612	591	21
5	**Total Beginning Balance in Power Charge Accounts**	**1,630**	**1,653**	**(23)**
6	*Power Charge Accounts Operating Revenues*			-
7	Power Charge Revenues[4]	4,081	4,191	(110)
8	Other Revenue[5]	52	190	(137)
9	Interest Earnings on Fund Balances	78	80	(2)
10	**Total Power Charge Accounts Operating Revenues**	**4,211**	**4,461**	**(250)**
11	*Power Charge Accounts Operating Expenses*			-
12	Administrative and General Expenses	28	26	2
13	Total Power Costs[6]	4,489	4,540	(51)
14	**Total Power Charge Accounts Operating Expenses**	**4,516**	**4,566**	**(49)**
15	Net Operating Revenues	(305)	(105)	(200)
16	**Ending Aggregate Balance in Power Charge Accounts**	**1,325**	**1,549**	**(223)**

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.	327	318	9
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 and (ii) 12% of the Department's projected annual operating expenses for the current or immediately preceding Revenue Requirement Period.	558	612	(55)
Total Operating Reserves:	885	930	(45)

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the 2007 Revised Determination.
[4]Includes Bundled customer revenues and CRS revenues, whether from Direct Access or other sources, such as Community Choice Aggregation.
[6]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 PROPOSED 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	177	184	(8)
3	Bond Charge Payment Account	607	591	15
4	Debt Service Reserve Account	930	913	18
5	**Total Beginning Balance in Bond Charge Accounts**	**1,714**	**1,688**	**25**
6	*Bond Charge Accounts Revenues*			
7	Bond Charge Revenues from Utiltities[4]	834	818	16
8	Bond Charge Revenues from Direct Access Customers	-	-	-
9	Interest Earnings on Fund Balances	82	79	3
10	**Total Bond Charge Accounts Revenues**	**916**	**897**	**19**
11	*Bond Charge Accounts Expenses*			
12	Debt Service on Bonds[5]	931	920	11
13	**Total Bond Charge Accounts Expenses**	**931**	**920**	**11**
14	Net Bond Charge Revenues	(15)	(23)	8
15	**Ending Aggregate Balance in Bond Charge Accounts**	**1,699**	**1,665**	**33**

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 - 79	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	323 - 827	318 - 810	
Debt Service Reserve Account: Established as the maximum annual debt service	939	930	9

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the 2007 Revised Determination.
[4]CRS Bond Charge 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 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, 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 Proposed Determination.

PRIOR PROCEEDINGS RELATING TO 2007 AND THE PROJECTED STARTING BALANCE FOR 2008

On August 2, 2006, the Department published its Determination of Revenue Requirements for the period of January 1, 2007 through and including December 31, 2007 and submitted it to the Commission. The August 2, 2006 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 2, 2006 Determination, including, but not limited to, operating results of the Electric Power Fund (the "Fund") as of September 30, 2006 (the August 2, 2006 Determination incorporated preliminary actual operating results through June 2006); and an updated gas price forecast. On October 30, 2006 the Department revised its August 2, 2006 Determination under Section 516 of the Regulations to address the following matters:

- Updated actual Electric Power Fund operating results through September 30, 2006;
- Updated Natural Gas Price Forecasts and Related Assumptions; and
- Updated interest rate assumptions affecting interest earnings projections and debt service on variable rate debt.

These revisions resulted in a total decrease in the Revised 2007 Determination of $128 million relative to the August 2, 2006 Determination (the cash basis revenue requirement presented in the August 2, 2006 Determination totaled $5.138 billion). This decrease was comprised of two components: a $115 million decrease in the Department's Power Charge Revenue Requirement; and a $13 million decrease in the Department's Bond Charge Revenue Requirement.

The $115 million Power Charge Revenue Requirement decrease primarily resulted from the net effects of a decrease in contract costs due to a decrease in the gas price forecast for 2007.

The October 30, 2006 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 submitted its October 30, 2006 Determination to the Commission.

On December 14, 2006, the Commission issued Decision 06-12-035: "Order Allocating the 2007 Revenue Requirement Determination of the California Department of Water Resources".

THE 2008 DETERMINATION

The Department sent requests for information to each IOU on April 10, 2007, which solicited an update of various modeling assumptions and operational considerations. During April and May, the Department received responses to its requests for information from the IOUs.

The information obtained from the IOUs serves as the basis for the Department's analytical and forecasting efforts related to this 2008 Proposed Determination. The Department also considered other important criteria, including but not limited to Commission Decisions and Bond Indenture requirements. The resulting data was incorporated into the PROMOD IV market simulation model, and became a part of the projections leading to this 2008 Proposed Determination.

Upon completion of the procedures set forth in the regulations promulgated pursuant to the California Administrative Procedures Act (the "Regulations"), the Department will determine its revenue requirements for the 2008 Revenue Requirement Period.

C. THE DEPARTMENT'S PROPOSED 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 Department Costs: (a) $4.489 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) $(305) million in other net changes to Power Charge Accounts (including operating reserves). This projection results in a total revenue requirement of $4.211 billion.

Funds to meet these costs (in addition to surplus operating reserves) are projected to be provided from (a) $52 million from the Department's share of surplus power sales revenues; (b) $78 million of interest earned on Power Charge Account balances; and (c) $4.081 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:
PROPOSED RETAIL CUSTOMER POWER CHARGE CASH REQUIREMENT

Line	Description	Amounts for Revenue Requirement Period				
		Q1	Q2	Q3	Q4	Total
0	*Power Charge Accounts Expenses*					-
1	Power Costs	1,120	980	1,216	1,172	4,489
2	Administrative and General Expenses	7	7	7	7	28
3	Net Changes to Power Charge Account Balances	(88)	(33)	(147)	(37)	(305)
4	**Total Power Charge Accounts Expenses**	**1,040**	**955**	**1,075**	**1,142**	**4,211**
5	*Power Charge Accounts Revenues*					
6	Other Power Sales Revenues	23	9	8	12	52
7	Interest Earnings on Power Charge Account Balances	20	20	19	18	78
8	Total Power Charge Revenue Requirement	996	925	1,048	1,112	4,081
9	**Total Power Charge Accounts Revenues**	**1,040**	**955**	**1,075**	**1,142**	**4,211**

During 2008, the Department projects that it will incur the following Bond Related Costs: (a) $931 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) $(15) million for changes to Bond Charge Account balances, resulting in total Bond Charge Account expenses of $916 million.

Funds to meet these requirements are provided from (a) $82 million in interest earned on Bond Charge Account balances, and (b) $834 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: PROPOSED RETAIL CUSTOMER BOND CHARGE CASH REQUIREMENT

Line	Description	Amounts for Revenue Requirement Period				
		Q1	Q2	Q3	Q4	Total
0	*Bond Charge Accounts Expenses*					
1	Debt Service Payments	72	634	73	152	931
2	Net Changes to Bond Charge Account Balances	135	(410)	165	94	(15)
3	**Total Bond Charge Accounts Expenses**	**208**	**224**	**238**	**246**	**916**
4	*Bond Charge Accounts Revenues*					
5	Interest Earnings on Bond Charge Account Balances	13	30	12	27	82
6	Retail Customer Bond Charge Revenue Requirement	195	193	227	219	834
7	**Total Bond Charge Accounts Revenues**	**208**	**224**	**238**	**246**	**916**

In aggregate, the Department's total cash basis expenses are projected to be $5.447 billion. Revenues from interest earned and other power sales are projected to be $212 million, and net changes in fund balances are projected to be $(320) million, resulting in combined customer revenue requirements of $4.915 billion.

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

This Proposed 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 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	92,223	8,930	83,293
Southern California Edison	97,419	11,718	85,701
San Diego Gas & Electric	21,738	4,069	17,669
Total	**211,380**	**24,717**	**186,663**

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

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 Proposed 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.

[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 Proposed 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-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	181,907
Supply from Utility Resources	115,037
Net Short	66,870
Supply from the Department's Priority Long-Term Power Contracts	50,460
Off-System Sales	(2,456)
Residual Net Short (Surplus)	18,866

Table D-4 shows, on a quarterly basis for the Proposed 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.

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	16,413	11,806	1,053	(761)	(39)	5,367
Q2-2008	15,322	11,711	999	(649)	(26)	4,259
Q3-2008	17,917	13,978	1,241	(581)	(31)	4,520
Q4-2008	17,219	12,965	1,114	(465)	(29)	4,719
Total	66,870	50,460	4,408	(2,456)	(125)	18,866

[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 50,460 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 economic considerations to achieve the lowest possible total cost of power to IOU customers. 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 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 is all to NP15 during April through September, with some SP15 deliveries folded in during October through March. 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 latest annual delivery plan. With respect to the Department's long-term power contract with the City and County of San Francisco, an on-line date for the new generating units of January 2009, and an estimated capacity price of $171/kW-yr, has been assumed. 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. (Long-Term Commodity Sale)	2/26/2001 Renegotiated on 4/22/02	7/1/2002	12/31/2009	1000	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
"	"	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

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
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	Est. 1/2009		Est. 192	PG&E
Sempra Energy Resources	5/4/2001	1/1/2004	9/30/2011	1200	SCE
"	"	1/1/2004	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
"	"	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 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. For this reason, under present market conditions and terms of the contracts, the Department does not believe that termination of any of the contracts would result in a reduction in its revenue requirements or overall ratepayer costs.

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

As with any retail provider of energy, the Department and IOUs together, from time to time, purchase 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

[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.

surplus power sales will be less than the price paid for power. However, these minimal losses are an expected incident of appropriate 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 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	216	545	761		11	28	39		51
Q2-2008	198	451	649		8	18	26		41
Q3-2008	168	413	581		9	22	31		53
Q4-2008	154	311	465		10	19	29		62
Total	736	1,720	2,456		38	87	125		51

[1]All revenues presented on an accrual basis

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 $4.408 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	88
Quarter 2 – 2008	84
Quarter 3 – 2008	87
Quarter 4 – 2008	84

NATURAL GAS PRICE FORECAST AND FUELS ASSUMPTIONS

The natural gas price forecast supporting this 2008 Proposed Determination is based on a forecast prepared by Navigant Consulting, Inc. ("NCI"), consultants to DWR, using the Gas Market Data and Forecasting System owned by Energy and Environmental Analysis, Inc. ("EEA"), with certain assumptions specified by NCI. These assumptions include the timing of major gas pipeline capacity changes, the prices of crude oil and coal and the timing and magnitude of certain liquefied natural gas ("LNG") capacities, imports and exports. The EEA model uses a structural, network simulation of the natural gas markets in the U.S. and Canada to solve for natural gas production volumes, gas demand by sector, gas flows, storage activity, and gas prices at over 100 market "nodes" in North America.

The initial model results are then reviewed by NCI and compared with NYMEX forward prices. Based on NCI's review of the initial price forecast at Henry Hub, DWR determined that a price adjustment at this node was necessary to reflect current observations in natural gas markets. For the gas price forecast underlying this 2008 Proposed Determination, the annual price at Henry Hub was calculated on April 13, 2007 by averaging the then ten most recent daily settlement prices of the twelve NYMEX contracts for deliveries in 2008. The difference between the initial annual average price forecast at Henry Hub and the recalculated average annual price was used to proportionately adjust the forecasted prices at other market nodes, including PG&E Citygate and the Southern California Border.

Compared to the base case forecast underlying the 2007 Final Revised Determination published October 30, 2006, prices in the base case forecast supporting this 2008 Proposed 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 – 2008 Proposed Determination	8.74	8.37
Gas Price Forecast – 2007 Final Revised Determination	8.78	9.31
Difference	(0.04)	(0.94)

Table D-9 below lists the updated natural gas prices by quarter for 2008 and 2009 at two key California pricing 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	9.65	9.47	9.80	9.64
Q2	8.06	7.80	8.19	8.00
Q3	8.20	7.98	8.32	8.11
Q4	8.91	8.49	9.06	8.65
Annual Average	**8.70**	**8.44**	**8.84**	**8.60**

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 $79 million, based on the difference between the contract fuel price of $4.09 and the Department's projected average fuel price of $8.70 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.

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 support, and financial advisory services for managing the $10 billion debt portfolio and related reserves.

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 June 30, 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 200 million MMBtu during calendar year 2008. The hedged volume represents approximately 90 percent of total projected IOU stress 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 180 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, was 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 Proposed 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 Proposed 2008 Determination, all proposed NYMEX hedges use the margin requirement price for gas contracts and the price for basis swaps quoted on July 18, 2007 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 2007 Revenue Requirement is projected to be $120 million.

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, the 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 Proposed 2008 Revenue Requirement Period will be $834 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 Proposed Determination.

Information specific to certain Accounts for this 2008 Proposed 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 Proposed 2008 Determination, the Department has determined the MOEAB to be $327 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, in the case of clause (i) above, may take into account a range of possible future outcomes (i.e., "stress cases").

Based on the "stress" operating conditions (later described in the "Sensitivity Analysis" portion of Section D), the ORAR for the Proposed 2008 Revenue Requirement Period is determined by the Department to be $558 million, reflecting an amount equal to 12 percent of the Department's Operating Expenses for the most recent 12-month period ending April 30, 2007.

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 $939 million.

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 cash flow projections based on changes in certain key expense and operating assumptions ("Stress Cases"). 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 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	17.86	17.52	17.72
Q2 – 2008	14.49	14.33	14.51
Q3 – 2008	14.78	14.61	14.76
Q4 – 2008	16.01	16.04	16.24
Annual Average	15.79	15.62	15.81

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 June 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, 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, and includes the impact of actual and planned gas hedges in place as of April 30, 2007.

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 accelerated economic growth in California and decreases in the expected amount of 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 Proposed 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 and April 2007 totaling $23.6 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 $1.5 million from the Reliant Energy Settlement dated October 12, 2005.

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 Proposed 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 nodal market.

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. 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

THE PROPOSED 2008 DETERMINATION

THE DEPARTMENT WILL MAKE A JUST AND REASONABLE DETERMINATION AFTER COMPLETION OF ITS ADMINISTRATIVE PROCESS

Under the terms of the Rate Agreement between the Department and the Commission, and the terms of the Bond Indenture, the Department has agreed to review, determine and revise its Retail Revenue Requirement at least annually.

The Department issues this Proposed Determination of Revenue Requirements for the period January 1, 2008, through December 31, 2008 for public comment under the Regulations promulgated pursuant to the California Administrative Procedures Act. Under the Regulations, any determination that this Proposed 2008 Determination is just and reasonable will be made by the Department after review of comments from interested persons. The administrative process may result in the issuance of a determination of revenue requirements for 2008 that differs from this Proposed 2008 Determination.

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 proposed 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 I of the Proposed 2008 Revenue Requirement.

I. ANNOTATED REFERENCE INDEX OF MATERIALS UPON WHICH THE DEPARTMENT RELIED TO MAKE THE PROPOSED 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.
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.

Volume	Record Number	Date	Record Title
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.
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 and QF data.
DWR08pRR	032	07/17/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** PROMOD Base and Stress Case Results for Each Respective IOU.
DWR08pRR	033	07/19/07	**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: CERS** Estimate Of General And Administrative Costs.
DWR08pRR	036	07/03/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Sales Forecast Inputs to Promod.
DWR08pRR	037	07/19/07	**CONFIDENTIAL: NOT FOR PUBLIC RELEASE:** Revenue Requirement Hedging Workpaper.

Volume	Record Number	Date	Record Title
DWR08pRR	038	7/20/07	Review of WECC Market Simulation in the Development of the California Department of Water Resources' Revenue Requirement.
DWR08pRR	039	7/20/07	Calpine Plan of Reorganization: includes Press Release, Plan of Reorganization, Plan Supplement and disclosure Statement.