State of California

Department of Water Resources

Proposed Determination of Revenue Requirement

For the Period

January 1, 2013 through December 31, 2013

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

June 15, 2012

Table of Contents

List of Tables

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 ("Department" or "DWR") and the California Public Utilities Commission ("Commission" or "CPUC"), dated March 8, 2002 ("Rate Agreement"), and Division 23, Chapter 4, Sections 510–517 of the California Code of Regulations ("Regulations"), the Department hereby issues its Proposed Determination of Revenue Requirement for the period January 1, 2013 through December 31, 2013 ("Proposed 2013 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' ("Utilities" or "IOUs") 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 Requirement" (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 Requirement, 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 Proposed 2013 Determination contains information on the amounts required to be recovered, on a cash basis, in the 2013 Revenue Requirement Period (calendar year 2013).

For the 2013 Revenue Requirement Period, this Proposed 2013 Determination contains information regarding the following[2]: (a) the beginning balance of funds on deposit in the Electric Power Fund ("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 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

[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.

[2] Where appropriate, the Department has provided information in this Proposed 2013 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 Determination, quantitative statistics presented in tabular form may not add due to rounding.

purpose; and (c) the amount needed to pay the Department's costs, including all Retail Revenue Requirements.

DETERMINATION OF REVENUE REQUIREMENT

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 Proposed 2013 Determination (including the materials referenced in Section H), that it has a $1 million aggregate cash basis Power Charge Account revenue requirement for 2013[3]. The Department projects that it will have adequate reserves in its Power Charge Accounts at all times to pay all Department costs, return $116 million of excess amounts to customers and maintain reserves at sufficient levels to satisfy indenture required minimum balances, through an aggregate reduction in Power Charge Account balances of $165 million.

As required by the Act, the Rate Agreement, and the Regulations, the Department makes a separate revenue requirement determination for the Bond Charge Accounts. For 2013, the Department determines that its cash basis Bond Charge Account revenue requirement is $863 million.

This Proposed 2013 Determination takes into account preliminary actual operating results through April 2012.

Any net surpluses or deficiencies during the 2012 Revenue Requirement Period, which may result from the receipt of funds related to various litigation settlements involving the Department, variances in actual natural gas prices than those forecast and other considerations, are reflected in the Department's projected beginning 2013 operating balances.

Table A-1 shows a summary of the Department's revenue requirement and the accounts associated with projected Department Costs ("Power Charge Accounts") for 2013. These figures are compared to those reflected in the Department's Revised 2012 Determination of Revenue Requirements for the period of January 1, 2012 through and including December 31, 2012. A summary and comparison of the Department's revenue requirement 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.

[3] Power charge revenues are for accrued power sales in 2012, but received during the 2013 Revenue Requirement period.

TABLE A-1
SUMMARY OF THE DEPARTMENT'S 2013 POWER CHARGE REVENUE REQUIREMENT AND POWER CHARGE ACCOUNTS AND COMPARISON TO 2012[1]
($ Millions)

Line	Description	2013 [2]	2012 [3]	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	186	694	(508)
3	Priority Contract Account	-	-	-
4	Operating Reserve Account	68	288	(219)
5	**Total Beginning Balance in Power Charge Accounts**	**255**	**981**	**(727)**
6	*Power Charge Accounts Operating Revenues*			
7	Power Charge Revenues [4]	1	71	(69)
8	Return of Excess Amounts to Customers [5]	(116)	(690)	573
9	Interest Earnings on Fund Balances	1	3	(2)
10	**Total Power Charge Accounts Operating Revenues**	**(114)**	**(616)**	**502**
11	*Power Charge Accounts Operating Expenses*			
12	Administrative and General Expenses	19	21	(2)
13	Total Power Costs	32	246	(214)
14	**Total Power Charge Accounts Operating Expenses**	**51**	**267**	**(216)**
15	Net Operating Revenues	(165)	(883)	718
16	**Ending Aggregate Balance in Power Charge Accounts**	**90**	**99**	**(9)**

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.	68	63	5
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.	12	267	(255)
Total Operating Reserves:	80	330	(250)

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the 2012 Revised Determination.
[4]Includes Bundled Customer revenues and Cost Responsibility Surcharge revenues, whether from Direct Access or other sources, such as Community Choice Aggregation.
[5]Comprised of surplus reserves meeting the definition of Excess Amounts within the Power Supply Revenue Bond Indenture.

TABLE A-2
SUMMARY OF THE DEPARTMENT'S 2013 BOND CHARGE REVENUE REQUIREMENT AND BOND CHARGE ACCOUNTS AND COMPARISON TO 2012[1]
($ Millions)

Line	Description	2013[2]	2012[3]	Difference
1	*Beginning Balance in Bond Charge Accounts*			
2	Bond Charge Collection Account	222	193	29
3	Bond Charge Payment Account	668	673	(5)
4	Debt Service Reserve Account	919	919	-
5	**Total Beginning Balance in Bond Charge Accounts**	**1,809**	**1,785**	**24**
6	*Bond Charge Accounts Revenues*			
7	Bond Charge Revenues from Utiltities[4]	852	863	(11)
8	Interest Earnings on Fund Balances	20	20	1
9	**Total Bond Charge Accounts Revenues**	**872**	**883**	**(10)**
10	*Bond Charge Accounts Expenses*			
11	Debt Service on Bonds	909	901	9
12	**Total Bond Charge Accounts Expenses**	**909**	**901**	**9**
13	Net Bond Charge Revenues	(37)	(18)	(19)
14	**Ending Aggregate Balance in Bond Charge Accounts**	**1,772**	**1,767**	**5**

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	76 - 77	76 - 77	Same
Bond Charge Payment Account: An amount equal to the debt service accrued and unpaid through the end of the third next succeeding calendar month	311 - 974	314 - 981	Different
Debt Service Reserve Account: Established as the maximum annual debt service	919	919	-

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the 2012 Revised Determination.
[4]Cost Responsibility Surcharge revenues are included in this amount, whether from Direct Access or other sources, such as Community Choice Aggregation.

FUTURE ADJUSTMENT OF REVENUE REQUIREMENT

The Department may propose to revise its revenue requirement for the 2013 Revenue Requirement Period given the potential for significant or material changes in the California energy market including changes in forecasted fuel costs, the Department's associated obligations and operations, novation of its power contracts, 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 requirement 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 Requirement, copies of which have been incorporated into the administrative record supporting this Determination.

PROCEEDINGS RELATING TO 2012

On June 10, 2011, the Department issued its Proposed Determination of Revenue Requirement for 2012, 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 contract dispatch simulation model and Financial Model, subject to applicable non-disclosure requirements. Interested persons were advised to submit comments no later than July 1, 2011.

On August 4, 2011, the Department published its Determination of Revenue Requirement for the period of January 1, 2012 through and including December 31, 2012 and transmitted it to the Commission. Based on an assessment of all comments, the administrative record, the Act, the Regulations, Bond Indenture requirements and the Rate Agreement, the Department found the August 4, 2011 Determination just and reasonable.

The Department reviewed certain matters relating to its August 4, 2011 Determination, including, but not limited to, operating results of the Electric Power Fund (the "Fund") as of September 30, 2011 (the August 4, 2011 Determination incorporated preliminary actual operating results through May 2011); and an updated gas price forecast.

On October 17, 2011, the Department issued its Proposed Revised Determination of Revenue Requirement for 2012 (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 contract dispatch simulation model and Financial Model, subject to applicable non-disclosure requirements. Interested persons were advised to submit comments no later than October 24, 2011.

On October 27, 2011, the Department published its Revised Determination under Section 516 of the Regulations addressing the following matters:

1) Updated actual Electric Power Fund and Bond Account operating results through September 30, 2011.
2) Updated natural gas price forecasts and related assumptions.
3) Updated projections of direct access and bundled load volumes in PG&E's service territory based on updated information provided by PG&E.
4) Updated debt service projections after the issuance of $959,565,000 of State of California Department of Water Resources Power Supply Revenue, Series 2011N Bonds for purposes of; (1) reducing DWR's exposure to market uncertainties relating to the credit ratings of the providers of Credit Enhancement Facilities and relating to the limited availability of Credit Enhancement Facilities by refunding all remaining variable rate demand bonds previously issued by DWR under the Indenture with fixed rate refunding bonds and (2) achieving debt service savings by the issuance of fixed rate refunding bonds for the purpose of refunding a portion of its outstanding fixed rate bonds..

These revisions resulted in a total decrease in the Revised 2012 Determination of $8 million relative to the August 4, 2011 Determination. This decrease was entirely comprised of an $8 million decrease in the Department's Bond Charge Revenue Requirement. The $71 million Power Charge Revenue Requirement was not affected, since the 2012 projected power charge revenues were for accrued power sales in 2011, but received during the 2012 Revenue Requirement period.

As a result of the revisions, the Department planned to return $94 million more to customers than planned in the August 4, 2011 filing. The increased return of excess amounts is attributable to the net effects of an $11 million decrease in contract costs due to a decrease in the gas price forecast for the remainder of 2011 and 2012, and an $83 million increase to the forecasted ending 2011 cash balances from the August 4, 2011 filing forecast, as power costs continue to be below projections.

THE PROPOSED 2013 DETERMINATION

The Department sent requests for information to each IOU on April 13, 2012, 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 served as the basis for the Department's analytical and forecasting efforts related to this Proposed 2013 Determination. The Department also considered other important criteria, including, but not limited to, Commission Decisions, Bond Indenture requirements, the April 1, 2009 California Independent System Operator's Market Redesign and Technology Upgrade ("MRTU") implementation and related remittance processes, information pertaining to electric loads departing IOU service, and historical dispatch levels of Department contract facilities and similar peer group facilities. The resulting data was incorporated into spreadsheet-based analytical models that were used to estimate IOU load volumes subject to Power Charges and Bond Charges and Department contract volumes and costs, and became a part of the projections leading to the Proposed 2013 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 2013 Revenue Requirement Period.

C. THE DEPARTMENT'S PROPOSED DETERMINATION OF REVENUE REQUIREMENT FOR THE PERIOD JANUARY 1, 2013 THROUGH DECEMBER 31, 2013

PROPOSED REVENUE REQUIREMENT DETERMINATION

For 2013, the Department's revenue requirement consists of Department Costs and Bond Related Costs, which are to be satisfied primarily by Power Charge Revenues and Bond Charge Revenues, respectively.

During 2013, the Department projects that it will incur the following power procurement-related Costs: (a) $32 million for long-term power contract purchases to cover the net short requirement of customers and gas collateral costs; (b) $19 million in administrative and general expenses; (c) the return of $116 million of excess amounts to IOU customers; and (d) $(165) million net changes to Power Charge Accounts (including operating reserves). These projections result in total Power Charge expenses of $2 million.

Funds to meet these costs are projected to be provided from: (a) less than $1 million of interest earned on Power Charge Account balances; (b) $1 million from Power Charge Revenues and Cost Responsibility Surcharge ("CRS") revenues from customers other than customers of the IOUs and DWR.

Excess amounts as defined within the bond indenture shall be used, at the direction of the Commission after consultation with the Department, to (i) adjust customer charges, or (ii) with the agreement of the Department, reduce debt outstanding under the indenture, in all instances upon consideration of the interests of the retail customers of the IOUs and DWR. The Department will return only the amounts which meet the definition within this revenue requirement period as projected within this Proposed 2013 Determination. The Department projects that $116 million of excess amounts will be returned in 2013. The payments by the Department for the return of excess amounts will be separate from Power Charge receipts, which will continue to be based on delivery of power from the Department's long-term contracts and collected from customers of the IOUs.

Table C-1 provides a quarterly projection of costs and revenues associated with the Power Charge Accounts for the 2013 Revenue Requirement Period.

TABLE C-1
POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE: RETAIL CUSTOMER POWER CHARGE CASH REQUIREMENT[1]
($ Millions)

Line	Description	Amounts for Revenue Requirement Period				
		2013 - Q1	2013 - Q2	2013 - Q3	2013 - Q4	Total
1	*Power Charge Accounts Expenses*					
2	Power Costs	6	9	9	8	32
3	Administrative and General Expenses	5	5	5	5	19
4	Return of Excess Amounts to Customers	29	29	29	29	116
5	Net Changes to Power Charge Account Balances	(38)	(42)	(43)	(41)	(165)
6	**Total Power Charge Accounts Expenses**	**2**	**0**	**0**	**0**	**2**
7	*Power Charge Accounts Revenues*					
8	Interest Earnings on Power Charge Account Balances	0	0	0	0	1
9	Total Power Charge Revenue Requirement	1	-	-	-	1
10	**Total Power Charge Accounts Revenues**	**2**	**0**	**0**	**0**	**2**

[1]Numbers may not add due to rounding.

During 2013, the Department projects that it will incur the following Bond Related Costs: (a) $901 million for debt service on the Bonds, and (b) $(18) million for changes to Bond Charge Account balances, resulting in total Bond Charge Account expenses of $883 million.

Funds to meet this requirement are provided from: (a) $20 million in interest earned on Bond Charge Account balances; and (b) $863 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 2013 Revenue Requirement Period.

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

Line	Description	Amounts for Revenue Requirement Period				
		2013 - Q1	2013 - Q2	2013 - Q3	2013 - Q4	Total
1	*Bond Charge Accounts Expenses*					
2	Debt Service Payments	-	744	-	157	901
3	Net Changes to Bond Charge Account Balances	205	(534)	234	78	(18)
4	**Total Bond Charge Accounts Expenses**	**205**	**210**	**234**	**235**	**883**
5	*Bond Charge Accounts Revenues*					
6	Interest Earnings on Bond Charge Account Balances	1	9	1	9	20
7	Retail Customer Bond Charge Revenue Requirement	203	201	233	226	863
8	**Total Bond Charge Accounts Revenues**	**205**	**210**	**234**	**235**	**883**

In aggregate, the Department's total cash basis expenses are projected to be $952 million. In addition $116 million of Excess Amounts will be returned to customers. This results in a total cash requirement of $1.068 billion.

This cash requirement is projected to be met through $21 million in revenues from interest earned; a combined customer retail revenue requirement of $864 million; and net changes in fund balances of $(183) million.

D. ASSUMPTIONS GOVERNING THE DEPARTMENT'S PROJECTION OF REVENUE REQUIREMENT FOR THE 2013 REVENUE REQUIREMENT PERIOD

The Department based this Proposed 2013 Determination on a number of assumptions regarding retail customer load, power supply, natural gas prices, and 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 April and May 2012. The Department reviewed the utilities' underlying forecast assumptions and the 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 2013 energy requirements forecast (quantified in gigawatt hours) for the PG&E, SCE and SDG&E service areas during 2013 and represent forecasts at the customer meter.

TABLE D-1
ESTIMATED ANNUAL ENERGY REQUIREMENTS

Service Area	Bundled Load	Direct Access and CCA	Total Load
Pacific Gas & Electric	74,715	10,588	85,303
Southern California Edison	78,146	12,325	90,471
San Diego Gas & Electric	17,552	3,389	20,941
Total	170,413	26,302	196,715

DIRECT ACCESS

The Department's direct access estimates are based primarily on data provided by each IOU in April and May 2012. Where applicable, the data provided by each IOU was adjusted to account for the expected effects of Senate Bill (SB) 695.

On October 11, 2009, SB 695 was signed into law as an urgency statute. SB 695 allows individual retail nonresidential end-use customers to acquire electric service from other providers in each IOU service area, up to a maximum allowable limit. Except for this express authorization for increased direct access transactions under SB 695, the previously enacted suspension of direct access remains in effect.

On March 15, 2010, the CPUC issued Decision 10-03-022 which authorizes increases in the maximum direct access load for each IOU service area, as specified in SB 695. The maximum load of allowable direct access volumes is established for each IOU as the maximum total kWh supplied by all other providers to distribution customers of that IOU during any sequential 12-month period between April 1, 1998 and the effective date of the section of the Public Utilities Code modified by SB 695 (October 11, 2009).

The direct access maximum load authorized by the CPUC in Decision 10-03-022, if reached in all three service areas, would increase the percentage of each IOU's retail load attributable to direct access customers to approximately 14.0% in 2013. Decision 10-03-022 phases in the additional load allowance over a four-year period beginning on April 11, 2010. The amount of the additional load allowance to be phased in during 2010 and 2011 represents in each year the sum of 35% of each IOU's total additional load allowance; the amount of the additional load to be phased in during 2012 represents 30% of each IOU's total additional load allowance. The annual phase-in of the limits, combined with the concurrent expiration of several long-term contracts, should result in limited impacts to the Power Charges attributable to the increased limits. Regardless of the level of direct access participation within the IOU service areas, direct access customers will still be assessed Bond Charges and DWR's revenue requirement will be recovered in the same manner as has been successfully implemented over the duration of the Power Supply Program.

Table D-2 shows the 2013 direct access forecast for each IOU, as a percentage of total retail loads.

TABLE D-2
2013 DIRECT ACCESS FORECAST

Service Area	Percent of Retail Load
Pacific Gas & Electric	11.16%
Southern California Edison	13.62%
San Diego Gas & Electric	16.18%
Total	**12.58%**

COMMUNITY CHOICE AGGREGATION

Community Choice Aggregation, authorized by legislation enacted in 2002 ("AB 117"), refers to the ability of a city or county to aggregate all the electrical demand of the residents, businesses and municipal users under its jurisdiction and to meet this demand from an electricity provider other than an IOU, such as an independent electrical service provider. In the decision implementing AB 117, the CPUC has determined that future Community Choice Aggregation customers shall pay charges (including DWR charges) intended to prevent cost shifting to the bundled customers of the IOUs.

Pursuant to AB 117, three entities have filed Community Choice Aggregation Implementation Plans with the CPUC. The San Joaquin Valley Power Authority ("SJVPA") filed an Implementation Plan with the CPUC in January 2007, the Marin Energy Authority ("MEA") filed an Implementation Plan with the CPUC in January 2010 and the City and County of San Francisco ("CCSF") filed an Implementation Plan (as "CleanPowerSF") with the CPUC in March 2010. The SJVPA Implementation Plan was certified by the CPUC in May 2007, however, Community Choice Aggregation implementation was suspended by SJVPA in June 2009. The CleanPowerSF Implementation Plan was certified by the CPUC on May 18, 2010.

The MEA Implementation Plan was certified by the CPUC in February 2010; MEA is currently in the process of enrolling additional Community Choice Aggregation customers. MEA Member (municipal) accounts and a subset of residential, commercial and/or industrial accounts, comprising approximately 20 percent of MEA's total customer load, began service on May 7, 2010. MEA is expected to serve 758 GWh in 2012 and 762 GWh in 2013. This MEA load will reduce the bundled load in PG&E's service area.

Other communities have indicated a willingness to pursue Community Choice Aggregation, including several cities located to the east of San Francisco Bay, and the City of Victorville. However, none of these communities has yet filed an Implementation Plan with the CPUC. It is possible that Community Choice Aggregation could lead to substantial reductions in bundled sales volumes. In the CPUC proceeding implementing AB 117 concerning Community Choice Aggregation, the CPUC established that the Cost Responsibility Surcharge would be paid by Community Choice Aggregation customers and that the method for calculating the Cost Responsibility Surcharge adopted for direct access and municipal departing load customers, as modified by CPUC Decision 06-07-030 would also apply to Community Choice Aggregation customers.

POWER SUPPLY RELATED ASSUMPTIONS

In previous revenue requirement determinations, the Department considered three types of power supplies needed to meet the requirements of each IOU: (a) IOU supplied resources; (b) supply from the Department's long-term power contracts; and (c) the residual net short of each IOU. The significant decrease in the number of active long-term power contracts in 2012, and the amount of energy supplied to customers from those contracts, relative to previous years, has resulted in a revised methodology for estimating the amount of energy supplied to customers from the long-term contracts in 2013 and beyond. In this Proposed 2013 Determination, the Department only considered power supplied from the Department's long-term power contracts. For each contract, the Department considered historical monthly dispatch levels and outages, and the projections of dispatch provided by the IOUs responsible for managing each contract, in developing monthly estimates of contract energy supplied to customers.

For the Kings River Conservation District Contract, the Department projected its total dispatch using the methodology described above; additionally it calculated a remittance basis based on the historical ratio of CAISO day-ahead market to hour-ahead and real-time dispatch. The projected day ahead market dispatch will serve as the for customer remittances through Power Charges and the remaining energy quantities dispatched in the CAISO Real-time and Hour Ahead markets that will provide market revenues to the Department.

Table D-3 below shows, for the 2013 Revenue Requirement Period, the quarterly and annual estimated energy requirements for the customers of the IOUs and the expected supply from the Department's long-term power contracts.

TABLE D-3
ESTIMATED ENERGY REQUIREMENTS AND SUPPLY FROM THE DEPARTMENT'S LONG-TERM POWER CONTRACTS

Period	IOU Energy Requirements After Adjustments (GWh)	Supply from the Department's Priority Long-Term Power Contracts (GWh)	Percentage of IOU Energy Requirements Represented by the Department's Priority Long-Term Power Contracts	Priority Long-Term Power Contract Costs (millions of dollars)
Q1-2013	39,187	68	0.17%	7
Q2-2013	41,393	120	0.29%	9
Q3-2013	48,743	113	0.23%	9
Q4-2013	41,090	76	0.18%	7
Total 2013	**170,413**	**376**	**0.22%**	**32**

CONTRACT ASSUMPTIONS

During the 2013 Revenue Requirement Period, approximately 376 GWhs of energy is projected to be supplied on behalf of the IOUs' retail electric customers through the Department's long-term power contracts. The terms and conditions of each contract have been reflected in the Department's contract-specific, monthly energy dispatch estimates. The terms and conditions incorporated in the Department's estimation of contract volumes include, among other details, must-take energy volumes, dispatchable contract capacities, and historical contract dispatch levels. Energy volumes from the remaining Department's dispatchable and as-available long-term power contracts are estimated based on primarily on historical capacity factors for those contracts.

Table D-4 provides a listing of all of the long-term power contracts that are expected to be operational during the 2013 Revenue Requirement Period and beyond, describing the term and capacity associated with each contract and the IOU to which the contract has been allocated.

The majority of the Department's long term contacts have expired. There are only three remaining contracts for 2013: Kings River Conservation District – allocated to PG&E; and Shell Wind Cabazon and Shell Wind Whitewater Hill – allocated to SDG&E.

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

TABLE D-4
LONG-TERM POWER CONTRACT LISTING

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
Kings River Conservation District	12/31/2002 Renegotiated on 8/18/04	9/19/2005	9/18/2015	96	PG&E
Shell Wind (Cabazon Project)	7/12/2001 Renegotiated on 4/24/02	8/31/2002	12/31/2013	30	SDG&E
Shell Wind (Whitewater Hill Project)	7/12/2001 Renegotiated on 4/24/02	8/31/02 (partial)	12/31/2013	45	SDG&E

* Delivery volumes and locations, post-MRTU, resolved on 3/16/09. Available capacity varies by month. Capacity volumes shown are the maximum values for the contract remainder.

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.

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 requirement, 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 requirement 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 requirement 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 2013 Revenue Requirement Period. As of the date of this Proposed 2013 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 CPUC ordered certain classes of direct access, municipal and customer generation departing load, and Community Choice Aggregation customers to pay the Cost Responsibility Surcharge related to historical stranded costs and ongoing costs. Included in the Cost Responsibility Surcharge is a DWR Bond Charge component, which is assessed to pay debt service associated with DWR's bond issuances and a DWR Power Charge component, which pays a portion of the above-market costs of the DWR power portfolio. The Bond Charge and the Power Charge components are rates imposed on total electricity usage by direct access, departing load and Community Choice Aggregation customers by the CPUC in concert with the establishment of Power Charges and Bond Charges on bundled customers.

Cost Responsibility Surcharge revenues reduce the amount of Bond Charges and Power Charges that must be imposed on bundled customers to recover Bond Related Costs and Department Costs. In the aggregate, the payments by direct access load, departing load, and Community Choice Aggregation load and from bundled customer load for the DWR Bond Charge and the DWR Power Charge flow to DWR to recover the DWR Bond Related Costs and Department Costs.

SALES OF EXCESS ENERGY ASSUMPTIONS

As with any retail providers of energy, due to contract obligations and daily and monthly variations in the IOUs' retail customer loads, DWR and the IOUs together, from time to time, purchase more energy than is needed to serve their retail customers. In 2002, the CPUC issued a decision allocating each of the thirty-two DWR power purchase contracts in effect in 2002 to a specific IOU, and determining (with DWR's consent) that income from the forward market sale of DWR and IOU excess energy would be shared on a pro-rata basis between DWR and the IOUs.

In 2009, after consideration of the April 1, 2009 implementation of the MRTU, DWR and the IOUs jointly submitted a Memorandum of Understanding to the CPUC that clarified the process that the IOUs will use to remit Power Charges to DWR. This clarification became necessary due to changes in the manner in which energy is scheduled and settled in the MRTU market.

With respect to surplus sales, the IOUs and DWR focused on simplifying the remittance processes where possible. Specifically, the IOUs and DWR proposed to eliminate the sharing of surplus sales. Revenues from pro-rata sharing of surplus sales are no longer used to offset DWR's revenue requirement, but rather DWR will receive remittances on substantially all energy dispatched in the CAISO day-ahead market from DWR contracts in each IOU service area. Customers will remit Power Charges in amounts that will enable the recovery of ongoing operating costs of the Department's power supply program. Any energy dispatched in the CAISO hour-ahead or real-time markets will have associated market revenues provided to the Department.

LONG-TERM POWER CONTRACT COST ASSUMPTIONS

Each of the three remaining long-term power contracts identified in Table D-4 has been reviewed by the Department to determine the costs that will impact its revenue requirement during 2013. All applicable costs are reflected in the Department's contract dispatch and cost analysis, 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, fuel management fees, and carbon allowance costs. Total accrued long-term power contract costs, including requisite natural gas purchases, are projected to be $32 million for the 2013 Revenue Requirement Period. Natural gas costs represent a component of the Department's total energy costs and are discussed below in greater detail.

To comply with regulations required under AB32, there are Greenhouse Gas ("GHG") implementation fees and carbon allowance costs that will be incurred by the generating unit underlying the Kings River Conservation District ("KRCD") contract. DWR has included an estimate of those additional costs in the forecast for total power costs for the 2013 Revenue Requirement period.

For informational purposes, Table D-5 shows, for the 2013 Revenue Requirement Period, the expected average cost (in $/MWh) on a quarterly basis for the Department's long-term power contracts.

TABLE D-5
ESTIMATED POWER SUPPLY COSTS
(Dollars per Megawatt-Hour)

	Long-Term Priority Contracts
Quarter 1 – 2013	91
Quarter 2 – 2013	75
Quarter 3 – 2013	75
Quarter 4 – 2013	88

NATURAL GAS PRICE FORECAST AND FUELS ASSUMPTIONS

The natural gas price forecast supporting this Proposed 2013 Determination is based on the Department's Spring 2012 Natural Gas Price Forecast ("DWR Spring 2012 Forecast") Base Case prepared by Montague DeRose and Associates ("MDA"), advisors to the Department. The forecast is based on two sources of data, (1) NYMEX natural gas futures contract prices; and (2) the Energy Information Administration ("EIA") Short-term and Annual Natural Gas Price Forecasts.

In order to account for short term fluctuations in the natural gas market, NYMEX prices are used for the period of June 2012 through February 2014. To produce a long term forecast, MDA averaged a mid month May 2012 NYMEX price strip and the EIA Annual Energy Outlook (Apr 2011) to produce an annual long term forecast. This annual price forecast, is multiplied by monthly factors derived from the near term forecast in order to generate a monthly shaped long term price curve. The differences between the monthly price forecast at Henry Hub and specific price points -PG&E Citygate and the Southern California Border are derived using historical and forecasted basis differentials between market hubs.

Table D-6 reports the projected Base Case gas prices supporting this Proposed 2013 Determination and compares this forecast to the Base Case forecast underlying the Revised 2012 Determination published October 27, 2011.

TABLE D-6
NATURAL GAS PRICE FORECAST COMPARISON AT HENRY HUB
(Nominal $/MMBtu)

	2013	**2014**
Gas Price Forecast –Revised 2012 Determination	4.90	5.17
Gas Price Forecast –Proposed 2013 Determination	3.56	4.08
Difference	**(1.34)**	**(1.09)**

Table D-7 below lists the updated natural gas prices by quarter for 2013 and 2014 at two key California market hubs: PG&E Citygate and the Southern California Border.

TABLE D-7
NATURAL GAS AVERAGE PRICE FORECASTS
(Nominal $/MMBtu)

	Southern California Border		**PG&E Citygate**	
	2013	**2014**	**2013**	**2014**
Q1 – 2013	3.52	4.05	3.65	4.18
Q2 – 2013	3.55	3.98	3.73	4.15
Q3 – 2013	3.68	4.17	3.83	4.32
Q4 – 2013	3.84	4.48	4.01	4.65
Annual Average	**3.65**	**4.17**	**3.80**	**4.33**

GAS HEDGING EXPENSE

For the 2013 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 2011, monthly activity in the Department's Gas Hedging Account, and the Department's own internal analysis.

The Department estimates that as of April 30, 2012, the IOUs had collectively secured, or developed reasonably firm plans to secure, hedges on behalf of DWR that establish the effective price for 912,500 MMBtu during calendar year 2013. The hedged volume represents approximately 94 percent of total projected IOU base case gas requirements (for fuel related to allocated DWR power contracts) for the 2013 Revenue Requirement Period.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR MARKET REDESIGN AND TECHNOLOGY UPGRADE ASSUMPTIONS

The CAISO has completed an initiative called Market Redesign and Technology Upgrade ("MRTU") implementing a day-ahead wholesale electricity market designed to improve electricity grid management reliability, operational efficiencies and related technology infrastructure. MRTU was implemented on March 31, 2009. The redesigned CAISO energy markets under MRTU do not affect the projection and collection of the Bond Charges.

MRTU added significant market complexity. Since it is based on a nodal, as opposed to zonal, delivery point and pricing structure, it changed the way in which energy is scheduled and settled. DWR's power purchase contracts, as well as the Operating Arrangements and the Servicing Arrangements, were entered into prior to MRTU implementation and contained terms and conditions that did not anticipate MRTU. As a result, DWR needed to clarify provisions of its power purchase contracts with various counterparties. DWR also needed to clarify the basis for determining remittance and market sale of energy quantities dispatched from DWR's power purchase contracts. Finally, DWR had to discuss with the IOUs financial responsibility for certain CAISO costs associated with the delivery of DWR contract energy to retail customers.

DWR began discussions with the IOUs to identify the affected provisions of the power purchase contracts, as well as the Servicing Arrangements and Operating Arrangements, to align dispatch assumptions that assure the power charge revenue stream. DWR entered a Memorandum of Understanding dated February 4, 2009 (the "MOU") with the IOUs that sets forth the guiding principles and certain agreements related to operation and remittance principles and procedures based on their understanding of MRTU implementation at that time. DWR agreed with the IOUs to eliminate the sharing of surplus energy sales revenue. Since certain energy bids submitted into the CAISO's energy markets will continue to result in market sales revenues, the MOU also addresses specific instances when DWR will be entitled to receive such market revenues. The IOUs also agreed to continue their financial responsibility for load-related CAISO costs, such as congestion costs, in the MOU. The CPUC approved the MOU on March 13, 2009.

The MOU was intended to be an interim step to allow DWR to achieve sufficient certainty regarding MRTU operations with power purchase contract counterparties. Based on DWR's actual operating experience with the power purchase contracts after MRTU implementation, DWR and the IOUs have agreed to additional clarifications to the remittance procedures from the proposal included in the MOU. DWR provided revisions on September 20, 2010 to the then-currently effective Servicing Arrangements and the Operating Arrangements to the CPUC for approval; on March 15, 2011, the CPUC approved the revised Servicing Arrangements and Operating Arrangements for the three IOUs.

ADMINISTRATIVE AND GENERAL COSTS

The Department's administrative and general costs of $19 million consist of $15 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 $4 million for consulting services for development and monitoring of the revenue requirement, litigation and dispute resolution support, power contract management, and financial advisory services for managing the $7.1 billion debt portfolio and related reserves. The Department plans to collect its administrative and general costs through Bond Charges beginning in 2016.

FINANCING RELATED ASSUMPTIONS

For purposes of calculating the interest earnings on account balances during 2013, the Department assumes a 1.88 percent earnings rate for the Debt Service Reserve Account and a 0.30 percent earnings rate for all other accounts during the 2013 Revenue Requirement Period.

The Department currently has $7.127 billion of fixed rate bonds outstanding. The projected average interest rate for all fixed rate bonds for the 2013 Revenue Requirement Period is 4.77 percent.

The Department projects that the amount of Bond Charge Revenues required for the 2013 Revenue Requirement Period will be $863 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 Requirement, copies of which have been incorporated into the administrative record supporting this Proposed 2013 Determination.

Information specific to certain Accounts for this Proposed 2013 Determination follows.

OPERATING ACCOUNT

The Department has covenanted in the Bond Indenture to include in its revenue requirement 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 it 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 Case").

For the purposes of this Proposed 2013 Determination, the Department has determined the MOEAB to be $68 million. The Department projects to exceed the MOEAB at all times during 2013. 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) the remaining fixed cost obligations of the power supply portfolio and related administrative costs, (2) potential gas price volatility and (3) year-over-year revenue requirement volatility, as well as the factors discussed below under "Sensitivity Analysis" and in Section F—"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 Case").

Based on the Stress Case described below under "Sensitivity Analysis", the ORAR for the 2012 Revenue Requirement Period is determined by the Department to be $12 million, reflecting 12 percent of the Department's projected Operating Expenses through the end of the program.

DEBT SERVICE RESERVE ACCOUNT

For purposes of calculating the amount of the Debt Service Reserve Requirement in accordance with the Bond Indenture, the Department determines the Maximum Annual Debt Service ("MADS") for all outstanding Power Supply Revenue Bonds through final bond maturity. The MADS amount must be carried in the Debt Service Reserve Account at all times to satisfy Bond Indenture requirements.

For the 2013 Revenue Requirement Period, the Department has determined the Debt Service Reserve Requirement to be $919 million, equal to MADS. The Department projects to maintain this amount at all times during the 2013 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 Requirement 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, 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 using a Stress Case based on changes in certain key expense and operating assumptions. The Stress Case considered in this assessment reflects a sampling of groups of changes in key assumptions that could affect Department expenses and revenues. The Stress Case is not intended to reflect all possible scenarios, nor are they intended to reflect only those most likely to occur. For the Stress Case, perturbations on natural gas price forecasts and contract energy volumes were performed in order to generate revised energy delivery and contract cost forecasts and consequently revised cash flow projections for the Department. These revised results were compared against the base estimate of cash flow projections (the "Base Case").

STRESS CASE

This Stress Case focuses on increased costs of providing energy under the Department's long-term contracts, and also considers increased contract dispatch. Higher costs are driven primarily by increased fuel costs. The Stress Case natural gas price forecast is presented in Table D-8.

TABLE D-8
STRESS CASE – NATURAL GAS PRICE FORECASTS
(Nominal $/MMBtu)

	Henry Hub	Southern California Border	PG&E Citygate
	2013	**2013**	**2013**
Q1 – 2013	5.24	5.36	5.56
Q2 – 2013	5.28	5.43	5.70
Q3 – 2013	5.50	5.67	5.90
Q4 – 2013	5.88	6.02	6.28
Annual Average	**5.48**	**5.62**	**5.86**

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 2002 through April 2012 for Henry Hub gas prices with historical basis differentials used to estimate prices for each delivery point. The Department identified 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 April 30, 2012.

The Department also considered in the Stress Case increased contract dispatch. The power contract dispatch as increased by of two standard deviations around the median capacity factors. The resulting capacity factors are 20 percent higher than the median for the two Shell wind contracts, and 100 percent higher for the Kings River contract. The Department will address the risk associated with the wide potential variance in the dispatch of the Kings River facility by maintaining a level of funding in the Operating Account that incorporates the entire annual fixed cost of the Kings River contract.

E. POWER CONTRACT SETTLEMENT SUMMARY

The California Parties, which include the Governor's Office, California Attorney General's Office, CPUC, the Department, and the IOUs, have participated 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. Any future settlement distributions will reduce Department costs and, as a result, decrease the Department's revenue requirement. Copies of prior settlement agreements are incorporated into the administrative record supporting this Determination.

In the ten month period ended April 30, 2012, energy settlements were $35 million. The Department received $9 million from the CAISO as a result of market re-runs for 2001. The Department also received $9 million from the California Power Exchange as a result of a FERC ordered and Bankruptcy Court approved distribution of funds related to the energy crisis. The Department received a total of $12 million as part of three FERC refund settlement agreements signed by the California Parties and the City of Pasadena, the Modesto Irrigation District and Nevada Power, respectively. The Department also received $3 million from a California litigation escrow account as the final payment from a settlement agreement reached with Sempra in 2010. The Settlement funds received effectively reduce the Department's costs, and the Department has included the impact of the settlement funds in the Proposed 2013 Determination.

Additionally, in May 2012, the Commission issued Decision 12-05-006, regarding the reallocation of DWR's 2012 Revenue Requirement to affect a Settlement Agreement entered into by the IOUs on allocating the Continental Forge Discount and Sempra Long-Term Contract Refund. Additionally, because of the way the Department prepares its annual revenue requirements, the allocation changes may have an effect on 2012 ending cash balances after rate changes were completed by the IOUs during the 2012 Revenue Requirement period, These effects are included in this 2013 Proposed Revenue Requirement.

F. KEY UNCERTAINTIES IN THE REVENUE REQUIREMENT DETERMINATION

The Department faces a number of uncertainties that may require material changes to its revenue requirement for the 2013 Revenue Requirement Period after this Proposed 2013 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 requirement;
   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. 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; and
   b. Gas price volatility.

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; and
   b. Dispatch coordination between IOUs and DWR.

7) Uncertainties relating to electric industry and markets:

a. Electric transmission constraints; and
b. Gas transmission constraints.

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

9) Uncertainties relating to financial industry and markets:
a. Effects of bond refunding or similar action;
b. Variance in interest rates; and
c. Constraints in the flow and availability of credit facilities and capital.

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 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, 2007
Supplemental 2008	February 15, 2008
2009	August 6, 2008
Revised 2009	October 29, 2008
2010	August 6, 2009
Revised 2010	October 27, 2009
2011	August 5, 2010
Revised 2011	October 26, 2010
2012	August 4, 2011
Revised 2012	October 27, 2011

THE PROPOSED 2013 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, 2013, through December 31, 2013 for public review and comment under the Regulations promulgated pursuant to the California Administrative Procedures Act. Under the Regulations, any determination that this Proposed 2013 Determination is just and reasonable will be made by the Department after review of comments from interested parties. The administrative process may result in the issuance of a supplemental determination of revenue requirements for 2013 that differs from this Proposed 2013 Determination.

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

Volume	Record Number	Date	Record Title
DWR13pRR	1	8/16/2011	Official Statement - State of California Department of Water Resources Power Supply Revenue Bonds, Series 2010N
DWR13pRR	2	8/23/2011	Decision 11-08-007 Granting the Request of the California Department of Water Resources to Modify Decision 11-03-004 Regarding the 2011 Operating Order Applicable to San Diego Gas & Electric Company
DWR13pRR	3	10/27/2011	Revised Revenue Requirement Determination for 2012, including the Revised Determination, The Notice, and the Transmittal from CERS to the Commission
DWR13pRR	4	11/9/2011	DWR Electric Power Fund Audited Financial Statements, for Years ending 6/30/11 and 06/30/10
DWR13pRR	5	12/13/2011	Decision 11-12-005: "Decision Allocating The Revised 2012 Revenue Requirement Determination of The California Department of Water Resources"
DWR13pRR	6	2/15/2012	DWR Electric Power Fund Financial Statements, 12/31/11
DWR13pRR	7	4/13/2012	DWR "Gurdip Rehal" email transmittal of Data Request 1 to PG&E
DWR13pRR	8	4/13/2012	DWR "Gurdip Rehal" email transmittal of Data Request 1 to SCE
DWR13pRR	9	4/13/2012	DWR "Gurdip Rehal" email transmittal of Data Request 1 to SDG&E
DWR13pRR	10	4/27/2012	CONFIDENTIAL R.11-03-006 CDWR-SCE-01-2013 -- SCE DWR2013 - DR1-Q1 Attachment - Load_ Forecast - Response – Confidential
DWR13pRR	11	4/27/2012	CONFIDENTIAL R.11-03-006 CDWR-SCE-01-2013 Responses Q01a-h
DWR13pRR	12	4/27/2012	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E response to DWR Data Request DR-1 04272012
DWR13pRR	13	4/27/2012	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PGE - DWR2013 - DR1-Q1 Attachment - Load Forecast

DWR13pRR	14	4/27/2012	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PGE DWR-RevReq2013_DR_DWR_001-Q01
DWR13pRR	15	4/27/2012	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E DWR-RevReq2013_DR_DWR_001-Q02
DWR13pRR	16	5/2/2011	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: MDA "Brian Grubbs" email transmittal of Revised Data Request 1 to PGE requesting clarification of responses to DWR Data Request 1
DWR13pRR	17	5/2/2011	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: MDA "Brian Grubbs" email transmittal of Revised Data Request 1 to SDGE requesting additional clarification of responses to DWR Data Request 1
DWR13pRR	18	5/8/2012	DWR analysis of KRCD fixed payments
DWR13pRR	19	5/14/2012	Decision 12-05-006: Adopting Settlement on Allocation of the Continental Forge Settlement Discount and Sempra Long-Term Contract Refund
DWR13pRR	20	5/15/2012	DWR Electric Power Fund Financial Statements, 3/31/12
DWR13pRR	21	5/19/2012	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: IOU Load Forecast Model
DWR13pRR	22	5/19/2012	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Contract Dispatch and Cost Model – Base Case
DWR13pRR	23	5/25/2012	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E revised response to DWR Data Request 1, Question 1 SDGE - DWR2013 - DR1-Q1 Attachment - Load ForecastRev
DWR13pRR	24	5/30/2012	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Spring 2012 Base Case and Stress Case Gas Price Forecast
DWR13pRR	25	6/7/2012	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PGE revised response to DWR Data Request 1 PGE - DWR2013 - DR1-Q2 Attachment - DWR Contracts-revised_1
DWR13pRR	26	6/7/2012	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PGE revised response to DWR Data Request 1 DWR-RevReq2013_DR_DWR_001-Q02Supp01
DWR13pRR	27	6/15/2012	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: Financial Model (CFMG5V30u-2013 RR 6-15-2012 filing.xls) Projection of Revenue Requirement