State of California

Department of Water Resources

Proposed Determination of Revenue Requirement

For the Period

January 1, 2012 through December 31, 2012

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

June 10, 2011

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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 ("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, 2012 through December 31, 2012 ("Proposed 2012 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 2012 Determination contains information on the amounts required to be recovered, on a cash basis, in the 2012 Revenue Requirement Period (calendar year 2012).

For the 2012 Revenue Requirement Period, this Proposed 2012 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 2012 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 the entire Retail Revenue Requirement.

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 2012 Determination (including the materials referenced in Section H), that it will incur $277 million in costs in 2012. The Department projects that it will have adequate reserves in its Power Charge Accounts at all times to pay all Department costs, return $595 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 $798 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 2012, the Department determines that its cash basis Bond Charge Account revenue requirement is $860 million.

This Proposed 2012 Determination takes into account preliminary actual operating results through March 2011.

Any net surpluses or deficiencies during the 2011 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 2012 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 2012. These figures are compared to those reflected in the Department's final 2011 revenue requirement determination, as reflected in the Department's Revised 2011 Determination of Revenue Requirements for the period of January 1, 2011 through and including December 31, 2011 (as so reflected, the "Revised 2011 Determination"). 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.

TABLE A-1
SUMMARY OF THE DEPARTMENT'S 2012 POWER CHARGE REVENUE REQUIREMENT AND POWER CHARGE ACCOUNTS AND COMPARISON TO 2011[1]
($ Millions)

Line	Description	2012[2]	2011[3]	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	611	1,044	(433)
3	Priority Contract Account	-	-	-
4	Operating Reserve Account	288	549	(261)
5	**Total Beginning Balance in Power Charge Accounts**	**899**	**1,594**	(695)
6	*Power Charge Accounts Operating Revenues*			
7	Power Charge Revenues from Bundled Customers[4]	71	509	(438)
8	Return of Excess Amounts to Customers[5]	(595)	-	(595)
9	Interest Earnings on Fund Balances	3	6	(3)
10	**Total Power Charge Accounts Operating Revenues**	**(521)**	**515**	(1,037)
11	*Power Charge Accounts Operating Expenses*			
12	Administrative and General Expenses	21	27	(6)
13	Total Power Costs	255	1,606	(1,351)
14	Gas Collateral Costs	1	46	(45)
15	**Total Power Charge Accounts Operating Expenses**	**277**	**1,679**	**(1,402)**
16	Net Operating Revenues	(798)	(1,164)	365
17	Net Transfers from/(to) Bond Charge Accounts & Adjustments	-	-	-
18	Total Net Revenues	(798)	(1,164)	365
19	**Ending Aggregate Balance in Power Charge Accounts**	**100**	**430**	**(330)**

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.	60	132	(72)
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 projected annual operating expenses and (iii) an amount equal to the maximum projected monthly priority contract cost payment.	70 - 256	288	Different
Total Operating Reserves:	130 - 316	419	Different

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the 2011 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 2012 BOND CHARGE REVENUE REQUIREMENT AND BOND CHARGE ACCOUNTS AND COMPARISON TO 2011[1]
($ Millions)

Line	Description	2012 [2]	2011 [3]	Difference
1	*Beginning Balance in Bond Charge Accounts*			
2	Bond Charge Collection Account	217	267	(49)
3	Bond Charge Payment Account	667	660	7
4	Debt Service Reserve Account	919	941	(22)
5	**Total Beginning Balance in Bond Charge Accounts**	**1,803**	**1,867**	**(64)**
6	*Bond Charge Accounts Revenues*			
7	Bond Charge Revenues from Utiltities[4]	860	860	(0)
8	Interest Earnings on Fund Balances	22	23	(0)
9	**Total Bond Charge Accounts Revenues**	**882**	**883**	**(1)**
10	*Bond Charge Accounts Expenses*			
11	Debt Service on Bonds	915	913	2
12	**Total Bond Charge Accounts Expenses**	**915**	**913**	**2**
13	Net Bond Charge Revenues	(33)	(30)	(3)
14	Net Transfers from/(to) Power Charge Accounts & Adjustments	-	-	-
15	Total Net Revenues	(33)	(30)	(3)
16	**Ending Aggregate Balance in Bond Charge Accounts**	**1,770**	**1,837**	**(67)**

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	77 - 77	70 - 77	Different
Bond Charge Payment Account: An amount equal to the debt service accrued and unpaid through the end of the third next succeeding calendar month	316 - 962	315 - 948	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 2011 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 2012 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 2011

On June 9, 2010, the Department issued its Proposed Determination of Revenue Requirement for 2011, consistent with the requirements of Sections 80110 and 80134 of the California Water Code, and provided information consistent with the Regulations. The Department provided interested persons with quantitative results from its PROMOD market simulation and Financial Model, subject to applicable non-disclosure requirements. Interested persons were advised to submit comments no later than June 30, 2010.

On August 5, 2010, the Department published its Determination of Revenue Requirement for the period of January 1, 2011 through and including December 31, 2011 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 5, 2010 Determination just and reasonable.

The Department reviewed certain matters relating to its August 5, 2010 Determination, including, but not limited to, operating results of the Electric Power Fund (the "Fund") as of September 30, 2010 (the August 5, 2010 Determination incorporated preliminary actual operating results through May 2010); and an updated gas price forecast.

On October 18, 2010, the Department issued its Proposed Revised Determination of Revenue Requirement for 2011 (the "Proposed Revised Determination"), consistent with the requirements of Sections 80110 and 80134 of the California Water Code, and provided information consistent with the Regulations. The Department provided interested persons with quantitative results from its PROMOD market simulation and Financial Model, subject to applicable non-disclosure requirements. Interested persons were advised to submit comments no later than October 25, 2010.

On October 26, 2010, 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, 2010.
2) Updated natural gas price forecasts and related assumptions.
3) Updated projections of direct access volumes that consider levels of subscription in IOU service areas realized pursuant to SB 695.
4) Updated the interest rate on all unhedged variable rate bonds based on data through September 30, 2010.
5) Novation of the Calpine 2, Calpine Peaking, and GWF power contracts to PG&E consistent with Commission directives in D.10-07-042.
6) Issuance of $1,763,215,000 of State of California Department of Water Resources Power Supply Revenue, Series 2010M 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 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 2011 Determination of $424 million relative to the August 5, 2010 Determination. This decrease was comprised of two components: a $395 million decrease in the Department's Power Charge Revenue Requirement; and a $29 million decrease in the Department's Bond Charge Revenue Requirement.

The $395 million Power Charge Revenue Requirement decrease primarily resulted from the net effects of a decrease in contract costs due to a lower gas price forecast for the remainder of 2010 and 2011 and the novation of the Calpine 2, Calpine Peaking and GWF contracts. The $29 million Bond Charge Revenue Requirement decrease primarily resulted from the net effects of the 2010M restructuring, a decrease in the projections of interest rates for the unhedged variable rate portion of the Department's bond portfolio, and the result of a beginning 2010 balance in the Bond Charge Accounts that was higher than previously projected.

THE PROPOSED 2012 DETERMINATION

The Department sent requests for information to each IOU on April 8, 2011, 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 2012 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 2012 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 2012 Revenue Requirement Period.

C. THE DEPARTMENT'S PROPOSED DETERMINATION OF REVENUE REQUIREMENT FOR THE PERIOD JANUARY 1, 2012 THROUGH DECEMBER 31, 2012

PROPOSED REVENUE REQUIREMENT DETERMINATION

For 2012, 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 2012, the Department projects that it will incur the following power procurement-related Costs: (a) $256 million for long-term power contract purchases to cover the net short requirement of customers and gas collateral costs; (b) $21 million in administrative and general expenses; (c) the return of $595million of excess amounts to IOU customers; and (d) $(798) million net changes to Power Charge Accounts (including operating reserves). These projections result in a total revenue requirement of $74 million.

Funds to meet these costs are projected to be provided from: (a) $3 million of interest earned on Power Charge Account balances; (b) $71 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 2012 Determination. The Department projects $595 million of excess amounts will be returned in 2012. 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 2012 Revenue Requirement Period.

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

Line	Description	Amounts for Revenue Requirement Period				
		2012 - Q1	2012 - Q2	2012 - Q3	2012 - Q4	Total
1	*Power Charge Accounts Expenses*					
2	Power Costs	128	66	55	8	256
3	Administrative and General Expenses	5	5	5	5	21
4	Return of Excess Amounts to Customers	149	149	149	149	595
5	Net Changes to Power Charge Account Balances	(210)	(219)	(208)	(161)	(798)
6	**Total Power Charge Accounts Expenses**	**72**	**1**	**1**	**0**	**74**
7	*Power Charge Accounts Revenues*					
8	Interest Earnings on Power Charge Account Balances	1	1	1	0	3
9	Total Power Charge Revenue Requirement	71	-	-	-	71
10	**Total Power Charge Accounts Revenues**	**72**	**1**	**1**	**0**	**74**

During 2012, the Department projects that it will incur the following Bond Related Costs: (a) $915 million for debt service on the Bonds, payments of credit enhancement and liquidity facilities charges, and costs relating to other servicing arrangements in connection with the Bonds, and (b) $(33) million for changes to Bond Charge Account balances, resulting in total Bond Charge Account expenses of $882 million.

Funds to meet this requirement are provided from: (a) $22 million in interest earned on Bond Charge Account balances; and (b) $860 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 2012 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				
		2012 - Q1	2012 - Q2	2012 - Q3	2012 - Q4	Total
1	*Bond Charge Accounts Expenses*					
2	Debt Service Payments	11	731	11	162	915
3	Net Changes to Bond Charge Account Balances	196	(523)	219	75	(33)
4	**Total Bond Charge Accounts Expenses**	**207**	**208**	**230**	**237**	**882**
5	*Bond Charge Accounts Revenues*					
6	Interest Earnings on Bond Charge Account Balances	2	10	2	9	22
7	Retail Customer Bond Charge Revenue Requirement	205	199	229	228	860
8	**Total Bond Charge Accounts Revenues**	**207**	**208**	**230**	**237**	**882**

In aggregate, the Department's total cash basis expenses are projected to be $1.192 billion. Revenues from interest earned are projected to be $25 million, and net changes in fund balances are projected to be $795 million, resulting in a combined customer revenue requirement of $372 million.

D. ASSUMPTIONS GOVERNING THE DEPARTMENT'S PROJECTION OF REVENUE REQUIREMENT FOR THE 2012 REVENUE REQUIREMENT PERIOD

The Department based this Proposed 2012 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 2011. The Department reviewed the utilities' underlying forecast assumptions, including population growth, changes in employment and labor within the utility's service area, weather effects, and growth in distributed generation. In developing its bundled requirements forecast, the Department also reviewed forecasts of direct access and Community Choice Aggregation (CCA) in California. These assumptions are discussed in greater detail below.

Table D-1 shows the projected 2012 energy requirements forecast (quantified in gigawatt hours) for the PG&E, SCE and SDG&E service areas during 2012.

TABLE D-1
ESTIMATED ANNUAL ENERGY REQUIREMENTS

Service Area	Total Retail Requirements	Direct Access and CCA Requirements	Bundled Requirements
Pacific Gas & Electric	96,185	10,993	85,192
Southern California Edison	93,000	12,659	80,340
San Diego Gas & Electric	22,029	3,764	18,265
Total	**211,214**	**27,417**	**183,797**

DIRECT ACCESS

The Department's direct access estimates are based primarily on data provided by each IOU in April and May 2011. 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 2012 direct access forecast for each IOU, as a percentage of total retail loads.

TABLE D-2
2012 DIRECT ACCESS FORECAST

Service Area	Percent of Retail Load
Pacific Gas & Electric	10.55%
Southern California Edison	13.61%
San Diego Gas & Electric	17.09%
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. All remaining MEA accounts are currently expected to begin service within 24 months of May 7, 2010. MEA is expected to serve 158 GWh in 2011, 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.

Pursuant to Assembly Bill 80 (Public Utilities Code Section 366.1) and CPUC Decision 05-01-009, the City of Cerritos ("Cerritos"), as owner of the Magnolia Power Project, was granted authority to act as a community aggregator within the service area of SCE. Consistent with an agreement between Cerritos and SCE, the Cost Responsibility Surcharge paid by Cerritos' customers to SCE is the Cost Responsibility Surcharge applicable to Community Choice Aggregation customers. The methodology for calculating Cerritos' Cost Responsibility Surcharge was subsequently revised in CPUC Decision 07-04-007 to reflect the revisions approved in Decision 06-07-030. In 2010, the total Bond Charges paid by Cerritos were $201,170. The total Bond Charges and Power Charges paid by Cerritos in 2011 through April 30, 2011, were $70, 192 and $5,456, respectively.

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 2012 and beyond.

In this Proposed 2012 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.

Table D-3 below shows, for the 2012 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)
Q1-2012	43,286	1,703	3.9%	89
Q2-2012	44,045	1,383	3.1%	89
Q3-2012	51,126	125	0.3%	9
Q4-2012	45,339	82	0.2%	7
Total 2012	183,797	3,293	1.8%	195

CONTRACT ASSUMPTIONS

During the 2012 Revenue Requirement Period, approximately 3,293 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 Department's dispatchable and as-available long-term power contracts are estimated based 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 2012 Revenue Requirement Period and beyond, describing the term and capacity associated with each contract and the IOU to which the contract has been allocated.

A substantial number of contracts (13) will expire in 2011. Additionally, the two largest remaining contracts (Shell – allocated to PG&E; and Sunrise – allocated to SDG&E) expire on June 30, 2012.

Detailed contract terms can be found on the CERS website, http://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
Sunrise Power Company, LLC	6/25/2001 Renegotiated on 12/31/02	6/01/2003	6/30/2012	572	SDG&E
Shell (formerly Coral Power, LLC)	5/24/2001	1/1/2006	6/30/2010	400	PG&E
"	"	7/1/2010	6/30/2012	223-495*	PG&E
"	"	7/1/2002	6/30/2012	25-100*	PG&E
"	"	7/1/2003	3/31/2012	25-75*	PG&E
"	"	7/1/2004	3/31/2012	25-75*	PG&E
Shell Wind (Cabazon Project)	7/12/2001 Renegotiated on 4/24/02	8/31/2002	12/31/2013	43	SDG&E
Shell Wind (Whitewater Hill Project)	7/12/2001 Renegotiated on 4/24/02	8/31/02 (partial)	12/31/2013	65	SDG&E

* Delivery volumes and locations, post-MRTU, resolved on 3/16/09. Available capacity varies by month. Capacity volumes shown are the minimum and 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. One of the remaining original contracts (Shell - formerly Coral Power, LLC) has yet to be renegotiated from its 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 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 2012 Revenue Requirement Period. As of the date of this Proposed 2012 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.

LONG-TERM POWER CONTRACT COST ASSUMPTIONS

Each long-term power contract identified in Table D-4 has been reviewed by the Department to determine the costs that will impact its revenue requirement during 2012. 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, and fuel management fees. Total accrued long-term power contract costs, including requisite natural gas purchases, are projected to be $195 million[3] for the 2012 Revenue Requirement Period. 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-5 shows, for the 2012 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 – 2012	53
Quarter 2 – 2012	65
Quarter 3 – 2012	74
Quarter 4 – 2012	87

NATURAL GAS PRICE FORECAST AND FUELS ASSUMPTIONS

The natural gas price forecast supporting this Proposed 2012 Determination is based on the Navigant Spring 2011 Natural Gas Price Forecast ("Navigant Spring 2011 Forecast") Base Case prepared by Navigant Consulting, Inc. ("Navigant"), consultants to the Department. Assumptions underlying the Navigant Spring 2011 Forecast include all significant supply and demand factors affecting the North American natural gas market such as the timing of major gas pipeline capacity changes, resource base additions and subtractions, gas demand, the price of crude oil, the timing and magnitude of certain liquefied natural gas ("LNG") capacities, imports and exports.

[3] Cost is on an accrual basis whereas Table A-1 reports costs on a cash basis

The Navigant Spring 2011 Forecast was prepared based upon the GPCM natural gas forecast model and yields long term monthly gas prices. In order to account for short term fluctuations in the natural gas market, NYMEX prices are used in the initial eighteen months of the forecast. For the gas price forecast underlying this Proposed 2012 Determination, the near term monthly prices at Henry Hub were revised on May 1, 2011 by averaging the then ten most recent daily settlement prices. The differences between the initial monthly price forecasts at Henry Hub and the recalculated monthly prices were used to proportionately adjust the forecasted prices at other market hubs, including PG&E Citygate and the Southern California Border.

Compared to the Base Case forecast underlying the Revised 2011 Determination published October 26, 2010, prices in the Navigant/DWR Spring 2011 Forecast Base Case supporting this Proposed 2012 Determination are shown in Table D-6.

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

	2012	**2013**
Gas Price Forecast –Revised 2011 Determination	5.06	4.81
Gas Price Forecast –Proposed 2012 Determination	5.02	5.29
Difference	**(0.04)**	**0.48**

Table D-7 below lists the updated natural gas prices by quarter for 2012 and 2013 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**	
	2012	**2013**	**2012**	**2013**
Q1	4.85	5.27	5.13	5.60
Q2	4.57	4.91	5.09	5.44
Q3	4.82	5.04	5.15	5.36
Q4	5.10	5.22	5.42	5.55
Annual Average	**4.83**	**5.11**	**5.20**	**5.49**

GAS HEDGING EXPENSE

For the 2012 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, 2011, the IOUs had collectively secured, or developed reasonably firm plans to secure, hedges on behalf of DWR that establish the effective price for over 15 million MMBtu during calendar year 2012. The hedged volume represents approximately 71 percent of total projected IOU base case gas requirements (for fuel related to allocated DWR power contracts) for the 2012 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.

To achieve operating results consistent with current assumptions set forth in the applicable revenue requirement, DWR has attempted to identify and implement new or modified procedures necessary for the administration of DWR's power purchase contracts under MRTU. To the extent that DWR has not sufficiently identified and implemented these procedures, the costs related to and associated with the dispatch and operation of DWR's power purchase contracts and DWR's recovery of Power Charges may be adversely affected.

The implementation of MRTU does not affect the Bond Charge.

ADMINISTRATIVE AND GENERAL COSTS

The Department's administrative and general costs of $21 million consist of $16 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 requirement, litigation and dispute resolution support, power contract management, and financial advisory services for managing the $7.8 billion debt portfolio and related reserves.

FINANCING RELATED ASSUMPTIONS

For purposes of calculating the interest earnings on account balances during 2012, the Department assumes a 1.98 percent earnings rate for the Debt Service Reserve Account and a 0.48 percent earnings rate for all other accounts during the 2012 Revenue Requirement Period.

The Department currently has $6.882 billion of fixed rate bonds outstanding and $0.948 billion of unhedged variable rate debt. The projected average interest rate for all fixed rate bonds for the 2012 Revenue Requirement Period is 4.775 percent.

For purposes of calculating the interest accruing on unhedged variable rate bonds during 2012, as well as any future revenue requirement periods, in accordance with the Bond Indenture, 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 2012 Revenue Requirement Period, on the basis of these assumptions, the interest rate on all unhedged variable rate bonds is projected to be 4.0 percent.

The Department projects that the amount of Bond Charge Revenues required for the 2012 Revenue Requirement Period will be $860 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 2012 Determination.

Information specific to certain Accounts for this Proposed 2012 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”) during at least the Revenue Requirement Period. The Bond Indenture leaves to the Department the discretion to 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 Cases”).

For the purposes of this Proposed 2012 Determination, the Department has determined the MOEAB to be $60 million. The Department projects to exceed the MOEAB at all times during 2012. 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 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 Cases”).

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

Due to the expiration of a majority of the Power Supply Contracts remaining in 2012 by June 30, 2012, DWR has determined its ORAR calculation at both the beginning of the 2012 Revenue Requirement Period and then again for July 1, 2012 through the end of the calendar year, to continue returning Excess Amounts to customers. Based on the Stress Cases described below under "Sensitivity Analysis", the ORAR for the first half of the 2012 Revenue Requirement Period is determined by the Department to be $256 million, reflecting an amount equal to the largest aggregate amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any consecutive seven calendar months in the 2012 Revenue Requirement Period. Based on the same Stress Cases described below, the ORAR for the second half of the 2012 Revenue Requirement Period is determined by the Department to be $70 million, reflecting an amount equal to the PCCRA.

DEBT SERVICE RESERVE ACCOUNT

For purposes of calculating the amount of the Debt Service Reserve Requirement from time to time, interest accruing on Variable Rate Bonds during any future period will be assumed to accrue at a rate equal to the greater of (a) 130 percent of the highest average interest rate on such Variable Rate Bonds in any calendar month during the twelve (12) calendar months ending with the month preceding the date of calculation, or such shorter period that such Variable Rate Bonds shall have been outstanding, or (b) 4.0 percent. For the 2012 Revenue Requirement Period, the Department will calculate projected interest on unhedged Variable Rate Bonds at 4.0 percent.

For the 2012 Revenue Requirement Period, the Department has determined the Debt Service Reserve Requirement to be $919 million. The Department projects to maintain this amount at all times during the Revenue Requirement Period.

SENSITIVITY ANALYSIS

The Rate Agreement requires the Department to evaluate its costs and cash flows on a monthly basis and to notify the Commission of its Retail Revenue 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, IOU controlled or "retained" generation ("Utility Retained Generation" or "URG") production levels, changing natural gas prices, and Department contract operations, among other factors.

To assess the adequacy of reserve levels, the Department and its consultants have prepared an additional assessment of Stress Cases based on changes in certain key expense and operating assumptions. The Stress Cases considered in this assessment reflect a sampling of groups of changes in key assumptions that could affect Department expenses and revenues. The Stress Cases are not intended to reflect all possible scenarios, nor are they intended to reflect only those most likely to occur. For the Stress Cases, 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").

CASE 1

This Stress Case focuses on decreased Power Charge revenues resulting from lower deliveries of energy from the Department's long-term contracts to customers, and increased costs of providing energy under the Department's long-term 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-7. This Stress Case gas price forecast, shown in Table D-8, was developed using basic statistical methods to define a high-end range of gas prices at the Henry Hub, Southern California Border and PG&E Citygate delivery points. These are the relevant primary delivery points for natural gas that would be procured to support the Department's long-term contracts.

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

	Henry Hub	**Southern California Border**	**PG&E Citygate**
	2012	**2012**	**2012**
Q1	7.17	6.95	7.76
Q2	6.82	6.38	7.70
Q3	7.01	6.88	7.82
Q4	7.50	7.44	8.35
Annual Average	**7.13**	**6.91**	**7.91**

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 2011 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, 2011. 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 occur when the amount of energy dispatched from the Department's contracts is lower than anticipated. This is driven primarily by a decrease in the net short energy requirements, which can occur as a result of increased URG and/or decreased customer load. As a proxy for these effects, the Department's analysis incorporates a combination of factors to arrive at a lower bound for estimated contract dispatch levels; specifically, a two standard deviation deduction was applied to the median historical capacity factors for the dispatchable and as-available contracts. Under a normal distribution function, two standard deviations, plus or minus, will bound 95 percent of the expected capacity factor levels. Lower levels of dispatch (and subsequently, lower volumes for which the Department receives a Power Charge) 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.

Decreases of two standard deviations around the median capacity factors of each contract type result in a capacity factor 20 percent lower than the median for the two Shell wind contracts, 30 percent lower than the median for the Sunrise contract, and 100 percent lower for the Kings River contract. The particularly wide variation in the Kings River contract is observed because the infrequent and sporadic utilization of the underlying peaking facility. This is not uncommon for a peaking facility. As a result of this wide variance, however, and the potential for almost all of the costs associated with this contract to be fixed costs that could be assessed to a very small level of delivered energy, the Department will address that risk by maintaining a level of funding in the Operating Account that incorporates the entire annual fixed cost of the Kings River contract.

CASE 2

This Stress Case focuses on increased costs of providing energy under the Department's long-term contracts, and considers increased contract dispatch.

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-8.

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. As a proxy for these effects, the Department's analysis incorporates a combination of factors to arrive at an upper bound for estimated customer sales; specifically, a two standard deviation upward adjustment was applied to the median historical capacity factors for the dispatchable and as-available contracts. As described in Case 1, under a normal distribution function, two standard deviations, plus or minus, will bound 95 percent of the expected capacity factor levels.

Increases of two standard deviations around the median capacity factors of each contract type result in a capacity factor that is 20 percent higher than the median for the two Shell wind contracts, 30 percent higher than the median for the Sunrise contract, and 100 percent higher for the Kings River contract. As in Case 1, 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.

On April 28, 2010, the CPUC issued a press release to the effect that an agreement in principle had been reached to settle disputes and claims related to DWR's long-term power purchase contract (the "Agreement") with Sempra Generation ("Sempra") and various other litigation involving Sempra relating to the California energy crisis of 2000 and 2001. Under the terms of the proposed settlement (the "Proposed Settlement"), in exchange for a cash payment by Sempra of approximately $400 million and certain other consideration, Sempra and certain of its affiliates would exchange mutual releases with DWR, the CPUC, the State Attorney General, SCE and PG&E (collectively with DWR, the "Settling Parties"), except for a limited number of enumerated exceptions, the mutual releases would cover all claims related to the Agreement, and all claims related to the short-term energy or ancillary services transactions in the western energy markets during 2000 and 2001. The specific terms of the Proposed Settlement were memorialized in the Short Term Settlement Agreement and the Long Term Contract Settlement Agreement executed on or about October 1, 2010 and October 14, 2010, respectively. While the settlement agreements were effective upon execution, some of the operative provisions, particularly the payment obligations, would only become effective after the Federal Energy Regulatory Commission (FERC) approved both agreements. On October 18, 2010, the Settling Parties and Sempra jointly submitted both agreements for FERC approval. Approval was provided by a FERC order of December 21, 2010, resulting in a finalized settlement (the "Settlement").

Under the terms of the Settlement, DWR and Sempra will continue to perform their respective obligations under the Agreement and the Agreement costs will continue to be included in DWR's revenue requirement; a price discount, however, is in effect for the remainder of the contract term (September 30, 2011), comprised of a $4.15/MWh energy discount plus $3.59 million deducted from each month's invoice. In addition, the Department has received a total of $232 million of cash settlement funds from Sempra, in January and February 2011. The Settlement funds from Sempra effectively reduce the Department's costs, and the Department has included the impact of the settlement funds in the Proposed 2012 Determination.

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 2012 Revenue Requirement Period after this Proposed 2012 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

THE PROPOSED 2012 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, 2012, through December 31, 2012 for public review and comment under the Regulations promulgated pursuant to the California Administrative Procedures Act. Under the Regulations, any determination that this Proposed 2012 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 2012 that differs from this Proposed 2012 Determination.

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

Volume	Record Number	Date	Record Title
DWR12pRR	001	10/06/10	Official Statement - State of California Department of Water Resources Power Supply Revenue Bonds, Series 2010M
DWR12pRR	002	10/26/10	Revised Revenue Requirement Determination for 2011, including the Revised Determination, The Notice, and the Transmittal letter from CERS to the Commission
DWR12pRR	003	11/23/10	DWR Electric Power Fund Financial Statements, 9/30/10
DWR12pRR	004	12/02/10	Decision 10-12-006: "Decision Allocating The Revised 2011 Revenue Requirement Determination of The California Department of Water Resources"
DWR12pRR	005	12/10/10	PG&E Advice Letter 3776-E: Revision to Electric Preliminary Statement Part DG, Power Charge Collection Balancing Account
DWR12pRR	006	12/13/10	SDG&E Advice Letter 2216-E: Revisions To The DWR Power Charge And DWR Bond Charge Pursuant To Decision 10-12-006.
DWR12pRR	007	12/21/10	FERC EL02-60-009: "Order Approving Uncontested Settlement re Public Utilities Commission of the State of California v. Sellers of Long-Term Contracts to the California Department of Water Resources et al Under EL02-60. et al."
DWR12pRR	008	12/23/10	SCE Advice Letter 2536-E-A: Supplemental Advice Letter for Revisions for the 2011 California Department of Water Resources Power and Bond Charges in Accordance With Decision 10-12-006 and Consolidation With Other Authorized Rate Changes
DWR12pRR	009	2/24/11	DWR Electric Power Fund Financial Statements, 12/31/10
DWR12pRR	010	3/10/11	Decision 11-03-004: "Decision Regarding the Request of The California Department of Water Resources to Modify the Decisions Concerning the Servicing and Operating Orders and Agreements"
DWR12pRR	011	4/08/11	DWR "Gurdip Rehal" email transmittal of Data Request 1 to PG&E
DWR12pRR	012	4/08/11	DWR "Gurdip Rehal" email transmittal of Data Request 1 to SCE

DWR12pRR	013	4/08/11	DWR “Gurdip Rehal” email transmittal of Data Request 1 to SDG&E
DWR12pRR	014	4/19/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E response to DWR Data Request 1, Question 1
DWR12pRR	015	4/21/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E response to DWR Data Request 1, Question 2
DWR12pRR	016	4/22/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E response to DWR Data Request 1, Question 3
DWR12pRR	017	4/22/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE partial response to DWR Data Request 1
DWR12pRR	018	4/22/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E partial response to DWR Data Request 1
DWR12pRR	019	4/26/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E revised response to DWR Data Request 1, Question 1
DWR12pRR	020	4/26/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E response to DWR Data Request 1, Question 2
DWR12pRR	021	4/26/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE response to DWR Data Request 1
DWR12pRR	022	5/02/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: NCI “Kreg McCollum” email transmittal of Revised Data Request 1 to SCE requesting clarification of responses to DWR Data Request 1
DWR12pRR	023	5/02/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: NCI “Kreg McCollum” email transmittal of Revised Data Request 1 to SCE requesting additional clarification of responses to DWR Data Request 1
DWR12pRR	024	5/03/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E response to requested clarification of responses to DWR Data Request 1
DWR12pRR	025	5/03/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E response to requested clarification of responses to DWR Data Request 1
DWR12pRR	026	5/10/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E revised response to DWR Data Request 1, Question 1
DWR12pRR	027	5/10/11	DWR analysis of KRCD fixed payments
DWR12pRR	028	5/12/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: Navigant Spring 2011 Base Case and Stress Case Gas Price Forecast
DWR12pRR	029	5/16/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE partial response to requested clarification of responses to DWR Data Request 1

DWR12pRR	030	5/18/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE partial response to requested clarification of responses to DWR Data Request 1
DWR12pRR	031	5/19/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: IOU Load Forecast Model
DWR12pRR	032	5/19/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Contract Dispatch and Cost Model – Base Case
DWR12pRR	033	5/19/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Contract Dispatch and Cost Model – Case 1
DWR12pRR	034	5/19/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Contract Dispatch and Cost Model – Case 2
DWR12pRR	035	5/20/11	DWR Electric Power Fund Financial Statements, 12/31/10
DWR12pRR	036	6/08/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: Fuel Hedging Workpaper
DWR12pRR	037	6/09/11	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: Financial Model (CFMG5V28s--2012RR filing 2011-06-09.xls) Projection of Revenue Requirement