State of California

Department of Water Resources

Proposed
Determination of Revenue Requirements

For the Period

January 1, 2011 through December 31, 2011

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

June 9, 2010

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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 Requirements for the period January 1, 2011 through December 31, 2011 ("Proposed 2011 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 Requirements" (as those terms are defined in the Rate Agreement), including power supply-related costs. Subject to the conditions described in the Rate Agreement and other Commission Decisions, Bond Charges and certain charges designed to recover Department Costs may also be imposed on the customers of Electric Service Providers (as that term is defined in the Rate Agreement).[1] Additional background material is contained in the Department's prior Determinations of Revenue Requirements, copies of which have been incorporated into the administrative record supporting this Determination.

Pursuant to Sections 80110 and 80134 of the California Water Code and the Rate Agreement, this Proposed 2011 Determination contains information on the amounts required to be recovered, on a cash basis, in the 2011 Revenue Requirement Period (calendar year 2011).

For the 2011 Revenue Requirement Period, this Proposed 2011 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

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[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 2011 Proposed 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 REQUIREMENTS

Pursuant to the Act, the Rate Agreement and the Regulations, the Department determines, on the basis of the materials presented and referred to by this Proposed 2011 Determination (including the materials referenced in Section J), that its cash basis revenue requirement for 2011 is $1.793 billion, consisting of $0.904 billion in Power Charges and $0.889 billion in Bond Charges.

This Proposed 2011 Determination takes into account preliminary actual operating results through May 2010.

Any net surpluses or deficiencies during the 2010 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 2011 operating balances.

Table A-1 shows a summary of the Department's revenue requirements and the accounts associated with projected Department Costs ("Power Charge Accounts") for 2011. These figures are compared to those reflected in the Department's final 2010 revenue requirement determination, as reflected in the Department's Revised 2010 Determination of Revenue Requirements for the period of January 1, 2010 through and including December 31, 2010 (as so reflected, the "Revised 2010 Determination"). A summary and comparison of the Department's revenue requirements and the accounts associated with its Bond Related Costs ("Bond Charge Accounts") is presented in Table A-2. Definitions of key accounts and sub-accounts are presented within each table.

TABLE A-1
SUMMARY OF THE DEPARTMENT'S PROPOSED 2011 POWER CHARGE REVENUE REQUIREMENTS AND POWER CHARGE ACCOUNTS AND COMPARISON TO 2010[1]
($ Millions)

Line	Description	2011[2]	2010[3]	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	1,008	1,281	(273)
3	Priority Contract Account	-	-	-
4	Operating Reserve Account	549	543	6
5	**Total Beginning Balance in Power Charge Accounts**	**1,557**	**1,824**	**(267)**
6	*Power Charge Accounts Operating Revenues*			
7	Power Charge Revenues[4]	904	2,126	(1,222)
8	Interest Earnings on Fund Balances	6	13	(6)
9	**Total Power Charge Accounts Operating Revenues**	**910**	**2,139**	**(1,228)**
10	*Power Charge Accounts Operating Expenses*			
11	Administrative and General Expenses	27	27	(0)
12	Total Power Costs[5]	1,872	2,809	(936)
13	**Total Power Charge Accounts Operating Expenses**	**1,899**	**2,836**	**(937)**
14	Net Operating Revenues	(989)	(698)	(291)
15	**Ending Aggregate Balance in Power Charge Accounts**	**568**	**1,126**	**(559)**

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.	177	190	(12)
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.	364	549	(185)
Total Operating Reserves:	541	739	(197)

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the 2010 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]Includes gas hedging and collateral amounts.

TABLE A-2
SUMMARY OF THE DEPARTMENT'S PROPOSED 2011 BOND CHARGE REVENUE REQUIREMENTS AND BOND CHARGE ACCOUNTS AND COMPARISON TO 2010[1]
($ Millions)

Line	Description	2011[2]	2010[3]	Difference
1	*Beginning Balance in Bond Charge Accounts*			
2	Bond Charge Collection Account	204	240	(36)
3	Bond Charge Payment Account	725	648	77
4	Debt Service Reserve Account	941	950	(9)
5	**Total Beginning Balance in Bond Charge Accounts**	**1,870**	**1,839**	**32**
6	*Bond Charge Accounts Revenues*			
7	Bond Charge Revenues from Utiltities[4]	889	896	(8)
8	Interest Earnings on Fund Balances	22	26	(4)
9	**Total Bond Charge Accounts Revenues**	**911**	**923**	**(11)**
10	*Bond Charge Accounts Expenses*			
11	Debt Service on Bonds[5]	919	951	(32)
12	**Total Bond Charge Accounts Expenses**	**919**	**951**	**(32)**
13	Net Bond Charge Revenues	(7)	(28)	21
14	**Ending Aggregate Balance in Bond Charge Accounts**	**1,863**	**1,811**	**53**

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 - 89	79 - 81	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	405 - 875	330 - 905	Different
Debt Service Reserve Account: Established as the maximum annual debt service	941	959	(18)

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the 2010 Revised Determination.
[4]Cost Responsibility Surcharge revenues are included in this amount, whether from Direct Access or other sources, such as Community Choice Aggregation.
[5]Debt service on bonds includes net qualified swap payments.

FUTURE ADJUSTMENT OF REVENUE REQUIREMENTS

The Department may propose to revise its revenue requirements for the 2011 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, and many other events that may materially affect the realized or projected financial performance of the Power Charge Accounts or the Bond Charge Accounts. In such event, the Department will inform the Commission of such material changes and will revise its revenue requirements accordingly. Several relevant factors are discussed in more detail within Section D.

B. BACKGROUND

THE ACT AND THE RATE AGREEMENT

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

PROCEEDINGS RELATING TO 2010

On June 18, 2009, the Department issued its Proposed Determination of Revenue Requirements for 2010, 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 July 9, 2009.

On August 6, 2009, the Department published its Determination of Revenue Requirements for the period of January 1, 2010 through and including December 31, 2010 and submitted 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 6, 2009 Determination just and reasonable.

The Department reviewed certain matters relating to its August 6, 2009 Determination, including, but not limited to, operating results of the Electric Power Fund (the "Fund") as of September 30, 2009 (the August 6, 2009 Determination incorporated preliminary actual operating results through May 2009); and an updated gas price forecast.

On October 15, 2009, the Department issued its Proposed Revised Determination of Revenue Requirements for 2010 (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 22, 2009.

On October 27, 2009 the Department published its revised Determination under Section 516 of the Regulations addressing the following matters:

1. Updated the actual Electric Power Fund operating results through September 30, 2009.
2. Updated natural gas price forecasts and related assumptions.
3. Updated modeling assumptions and operational considerations provided by the IOUs pertaining to underlying assumptions incorporated into the PROMOD market simulation model.
4. Updated the interest rate on all unhedged variable rate bonds based on data through September 30, 2009.
5. Updated projections of interest earnings on all account balances based on current interest rates reported by the California State Treasurer's Office for its Pooled Money Investment Account-Surplus Money Investment Fund
6. Increased the projection of Administrative and General Expenses

These revisions resulted in a total decrease in the Revised 2010 Determination of $162 million relative to the August 6, 2009 Determination. This decrease was comprised of two components: a $122 million decrease in the Department's Power Charge Revenue Requirement; and a $40 million decrease in the Department's Bond Charge Revenue Requirement.

The $122 million Power Charge Revenue Requirement decrease primarily resulted from the net effects of a decrease in projected contract costs due to a decrease in the gas price forecast for the remainder of 2009. The $40 million Bond Charge Revenue Requirement decrease primarily resulted from the net effects of a decrease in the projections of interest rates for the unhedged variable rate portion of the Department's bond portfolio and the result of higher than previously projected beginning 2010 balance in the Bond Charge Accounts.

THE PROPOSED 2011 DETERMINATION

The Department sent requests for information to each IOU on April 7, 2010, which solicited an update of various modeling assumptions and operational considerations. During April and May, the Department received responses to its requests for information from the IOUs.

The information obtained from the IOUs serves as the basis for the Department's analytical and forecasting efforts related to this Proposed 2011 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 the Department's analyses of IOU electric loads and resources. The resulting data was incorporated into the PROMOD market simulation model, and became a part of the projections leading to this Proposed Determination.

On May 12, 2010 DWR issued an aggregate principal amount of $2,992,540,000 of State of California Department of Water Resources Power Supply Revenue, Series 2010L 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.

Prior to the issuance of the 2010L Bonds for the purpose of refunding fixed rate bonds, DWR made a determination that there were present value savings which were greater than 3% of the amount of the bonds being refunded. Additionally, prior to the issuance of the 2010L Refunding Bonds for the purpose of refunding variable rate bonds, DWR determined that there were present value savings projected to result from the issuance of such 2010 Refunding Bonds.

The resulting reduction in debt service was incorporated into this Proposed Determination. The debt portfolio changes are included in the Financing Related Assumptions section.

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 2011 Revenue Requirement Period.

C. THE DEPARTMENT'S PROPOSED DETERMINATION OF REVENUE REQUIREMENTS FOR THE PERIOD JANUARY 1, 2011 THROUGH DECEMBER 31, 2011

PROPOSED REVENUE REQUIREMENT DETERMINATION

For 2011, the Department's revenue requirements consist of Department Costs and Bond Related Costs, which are to be satisfied primarily by Power Charge Revenues and Bond Charge Revenues, respectively.

During 2011, the Department projects that it will incur the following power procurement-related Costs: (a) $1.872 billion for long-term power contract purchases to cover the net short requirement of customers; (b) $27 million in administrative and general expenses; and (c) $(989) million in other net changes to Power Charge Accounts (including operating reserves). This projection results in a revenue requirement of $0.910 billion.

Funds to meet these costs (in addition to surplus operating reserves) are projected to be provided from (a) $6 million of interest earned on Power Charge Account balances; and (b) $904 million from Power Charge Revenues and Cost Responsibility Surcharge ("CRS") revenues from customers other than customers of the IOUs and DWR.

Table C-1 provides a quarterly projection of costs and revenues associated with the Power Charge Accounts for the 2011 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				
		2011 - Q1	2011 - Q2	2011 - Q3	2011 - Q4	Total
1	*Power Charge Accounts Expenses*					
2	Power Costs	566	451	541	315	1,872
3	Administrative and General Expenses	7	7	7	7	27
4	Net Changes to Power Charge Account Balances	(229)	(261)	(337)	(163)	(989)
5	**Total Power Charge Accounts Expenses**	**344**	**197**	**211**	**159**	**910**
6	*Power Charge Accounts Revenues*					
7	Other Power Sales Revenues	-	-	-	-	-
8	Interest Earnings on Power Charge Account Balances	2	2	1	1	6
9	Total Power Charge Revenue Requirement	342	195	209	158	904
10	**Total Power Charge Accounts Revenues**	**344**	**197**	**211**	**159**	**910**

During 2011, the Department projects that it will incur the following Bond Related Costs: (a) $919 million for debt service on the Bonds and related Qualified Swap payments, payments of credit enhancement and liquidity facilities charges, and costs relating to other financial instruments and servicing arrangements in connection with the Bonds, and (b) $(7) million for changes to Bond Charge Account balances, resulting in total Bond Charge Account expenses of $911 million.

Funds to meet these requirements are provided from (a) $22 million in interest earned on Bond Charge Account balances, and (b) $889 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 2011 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				
		Q1	Q2	Q3	Q4	Total
0	*Bond Charge Accounts Expenses*					
1	Debt Service Payments	165	562	92	100	919
2	Net Changes to Bond Charge Account Balances	47	(347)	152	140	(7)
3	**Total Bond Charge Accounts Expenses**	**213**	**215**	**243**	**240**	**911**
4	*Bond Charge Accounts Revenues*					
5	Interest Earnings on Bond Charge Account Balances	2	10	2	9	22
6	Retail Customer Bond Charge Revenue Requirement	211	206	242	231	889
7	**Total Bond Charge Accounts Revenues**	**213**	**215**	**243**	**240**	**911**

In aggregate, the Department's total cash basis expenses are projected to be $2.818 billion. Revenues from interest earned and other power sales are projected to be $29 million, and net changes in fund balances are projected to be $(996) million, resulting in combined customer revenue requirements of $1.793 billion.

D. ASSUMPTIONS GOVERNING THE DEPARTMENT'S PROJECTION OF PROPOSED REVENUE REQUIREMENTS FOR THE 2011 REVENUE REQUIREMENT PERIOD

The Department based this Proposed 2011 Determination on a number of assumptions regarding retail customer load, demand side management and conservation, power supply, natural gas prices, 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 2010. The Department reviewed the utilities' underlying forecast assumptions, including population growth, changes in employment and labor within the utility's service area, weather effects, growth in distributed generation, and annexation of the utility's service area by publicly owned utilities. In developing its bundled requirements forecast, the Department also reviewed forecasts of direct access and Community Choice Aggregation (CCA) in California. These assumptions are discussed in greater detail below.

Table D-1 shows the projected 2011 energy requirements forecast (quantified in gigawatt hours) for the PG&E, SCE and SDG&E service areas during 2011.

TABLE D-1
ESTIMATED ANNUAL ENERGY REQUIREMENTS

Service Area	Total Retail Requirements	Direct Access and CCA Requirements	Bundled Requirements
Pacific Gas & Electric	93,187	6,107	87,080
Southern California Edison	92,215	11,065	81,151
San Diego Gas & Electric	21,840	3,385	18,456
Total	**207,243**	**20,556**	**186,686**

DIRECT ACCESS

The Department's direct access estimates are based on data provided by each IOU in April and May 2010 and a review of monthly direct access reports produced by the Commission. The Department regularly reviews each utility's monthly report to the Commission on current direct access load and service request changes to identify any substantive developments that would require Departmental action.

While the option to elect direct access service is suspended until DWR no longer supplies power under the Act, the CPUC initiated a proceeding to consider whether, when or how direct access should be restored. On February 28, 2008, the CPUC approved a decision concluding that the suspension of direct access could not be lifted at the present time while DWR is still supplying power under the Act. However, the decision continued the proceeding to consider possible approaches to expediting DWR's exit from its role of supplying power under the Act. On November 21, 2008, the CPUC approved Decision 08-11-056 which adopted a plan with the goal of the early exit of DWR from its role as supplier of power to retail electric customers. Under this plan, DWR's power purchase contracts would be replaced by agreements between the IOUs and DWR's power supplier counterparties that are not detrimental to ratepayers, through novation and/or negotiation. Decision 08-11-056 set a goal for the execution of replacement agreements for all of DWR's power purchase contracts by January 1, 2010. As of June 1, 2010, no DWR power purchase contracts have been replaced. Following passage of SB 695 on October 11, 2009, described in the following paragraph, the assigned CPUC commissioner in the proceeding under which D.08-11-056 was issued stayed the schedules for progress reports of the working group established in the decision to develop protocols and strategies for negotiating replacement contracts.

On October 11, 2009, Senate Bill (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 territory, 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 level of direct access up to a maximum load, 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 would allow increases in the direct access maximum load in PG&E's service area of up to approximately 71%, in SCE's service area of up to approximately 51%, and in SDG&E's service area of up to approximately 15%. The direct access maximum load authorized by 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 11.1% for PG&E, 12.9% for SCE and 16.2% for SDG&E, which would increase the total percentage of IOU retail load attributable to direct access customers from 9.3% to approximately 14.1%. (based on 2010 load forecasts provided to DWR by the IOUs in April 2009). Decision 10-03-022 phases in these additional load allowances over a four-year period beginning on April 11, 2010. 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 each IOU's direct access forecast, as a percentage of total retail loads, for 2011.

TABLE D-2
2011 DIRECT ACCESS FORECAST[3]

Service Area	Percent of Retail Load
Pacific Gas & Electric	6.37
Southern California Edison	12.00
San Diego Gas & Electric	15.50
Total	**9.84**

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 Power and Bond charges) intended to prevent cost shifting to the bundled customers of the IOUs.

Significant volumes of Community Choice Aggregation load could lead to changes in DWR Power Charges to accommodate reduced IOU retail deliveries of DWR power. 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 in January 2010, and the City and County of San Francisco ("CCSF") filed an Implementation Plan with the CPUC in March 2010. The SJVPA plan was certified by the CPUC in May 2007; however, Community Choice Aggregation implementation was suspended by SJVPA in June 2009. To date, the CCSF Implementation Plan has not yet been certified by the CPUC.

The MEA Implementation Plan was certified by the CPUC in February 2010 and MEA is currently in the process of enrolling 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 scheduled to begin service within 24 months of May 7, 2010. MEA is expected to serve 106 GWh in 2011 and 756 GWh in 2012. This MEA load will reduce the bundled load in PG&E's service territory.

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

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[3] Figures in Table D-2 represent direct access as a percentage of total retail loads for 2011. These percentages correspond to direct access loads forecast by the IOUs in 2010.

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 2009, the total Bond Charges paid by Cerritos were $249,437.

POWER SUPPLY RELATED ASSUMPTIONS

In this 2011 Proposed Determination, 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.[4]

Table D-3 below shows, for the 2011 Revenue Requirement Period, the estimated energy requirements for the customers of the IOUs, estimated supplies from generation by the three IOUs,[5] the resulting net short, the expected supply from the Department's long-term power contracts, off-system energy sales and the residual net short.

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

	Amounts for the Revenue Requirement Period (GWH)
All Investor Owned Utilities	
Energy Requirements After Adjustments	181,571
Supply from Utility Resources	133,684
Net Short	47,887
Supply from the Department's Priority Long Term Power Contracts	23,024
Off-System Sales	(3,639)
Residual Net Short (Surplus)	28,501

4 While the Department has calculated and presented the residual net short requirements of the IOUs, pursuant to the Act, the Department has not made any provision for the cost of the residual net short requirements in its Determination for the 2011 Revenue Requirement Period. For purposes of this Proposed 2011 Determination, the residual net short for each IOU equals the projected amount of wholesale energy remaining to be procured by such IOU on behalf of ratepayers in its service area.

5 For purposes of this Proposed 2011 Determination, generation retained by the three IOUs is defined as the sum of generation owned by the IOUs, interruptible load, supply from contracts between the IOUs and qualifying facilities ("QFs") and other bilateral contracts.

Table D-4 shows, on a quarterly basis for the 2011 Revenue Requirement Period, estimated net short volumes in gigawatt-hours, supply from the Department's long-term power contracts and the residual net short.

TABLE D-4
NET SHORT, SUPPLY FROM THE DEPARTMENT'S LONG-TERM POWER CONTRACTS AND RESIDUAL NET SHORT IN 2011[1]

Period	Net Short (GWH)	Supply from Power Contracts (GHW)	Power Contract Costs (Millions of Dollars)	Off-System Sales Volumes (GWH)	Revenues from Off System Sales (Millions of Dollars)	(Residual Net Short) Spot Volume (GWH)
Q1-2011	13,816	6,798	496	(339)	(12)	7,357
Q2-2011	9,394	6,276	465	(2,152)	(78)	5,270
Q3-2011	14,207	6,674	519	(410)	(14)	7,942
Q4-2011	10,470	3,276	215	(738)	(32)	7,932
Total	47,887	23,024	1,695	(3,639)	(137)	28,501

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

UTILITY RESOURCES

The Department reviewed each utility's 2011 forecast of utility owned generation, qualifying facility ("QF") contract generation, and bilateral contract generation for consistency with the Department's own energy dispatch forecast. Where necessary, the Department updated its assumptions concerning QF contract terms and expiration dates, outage schedules, and net dependable resource capacity, among others, to reflect current details related to each IOU's resource portfolio.

HYDRO CONDITION ASSUMPTIONS

Normal hydrologic conditions are assumed for both California and the Pacific Northwest during 2011 and 2012. Neither the CEC nor the National Weather Service Northwest River Forecast Center has provided meaningful forecasts past the 2010 water year. Therefore, DWR has projected normal hydroelectric dispatch for the 2011 Revenue Requirement Period.

CONTRACT ASSUMPTIONS

During the 2011 Revenue Requirement Period, approximately 23,024 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 market simulation, resulting in a projection of contract-specific, hourly energy dispatches to meet the projected energy requirements of each IOU's retail customers. The terms and conditions incorporated in the Department's market simulation include, among other details, must-take energy volumes and dispatchable contract capacities, contract heat rates and unit outage rates as well as scheduling limitations. During market simulation, all energy dispatches from the Department's dispatchable long-term power contracts occur based on dispatch of available power supply resources in merit order of the cost of dispatch and delivery of those resources, subject to transmission delivery constraints, and the effective cost of those constraints. In general, each incremental generating unit is dispatched only if the incremental cost of generating an additional MWh from that unit is less than the cost of alternative sources that can provide to the same location.

Table D-5 provides a listing of all of the long-term power contracts that will be operational during the 2011 Revenue Requirement Period and beyond, describing the term and capacity associated with each contract and the IOU to which the contract has been allocated.

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

TABLE D-5
LONG-TERM POWER CONTRACT LISTING

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
CalPeak Power—Panoche, LLC	8/14/2001 Renegotiated on 5/2/02	12/27/2001	12/27/2011	52.6	PG&E
CalPeak Power--Vaca Dixon, LLC	8/14/2001 Renegotiated on 5/2/02	6/21/2002	12/31/2011	51.9	PG&E
CalPeak Power--El Cajon, LLC	8/14/2001 Renegotiated on 5/2/02	5/29/2002	12/31/2011	50.9	SDG&E
CalPeak Power—Border, LLC	8/14/2001 Renegotiated on 5/2/02	12/12/2001	12/12/2011	51.6	SDG&E
CalPeak Power—Enterprise, LLC	8/14/2001 Renegotiated on 5/2/02	12/8/2001	12/8/2011	52.5	SDG&E
Calpine Energy Services, L.P. (Calpine 2)	2/26/2001 Renegotiated on 4/22/02; Renegotiated on 12/7/2007	1/1/2008	12/31/2012	180	PG&E
Calpine Energy Services, L.P. (Peaking Capacity)	2/27/2001 Renegotiated on 4/22/02	8/1/2002	7/31/2011	495	PG&E
Coral Power, LLC	5/24/2001	7/1/2010	6/30/2012	100	PG&E
"	"	7/1/2002	6/30/2012	100	PG&E
"	"	7/1/2003	6/30/2012	175	PG&E
"	"	7/1/2004	6/30/2012	175	PG&E

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
Power Receivables Finance (formerly Allegheny Energy Supply Company, LLC)	3/23/2001 Renegotiated on 6/10/03	1/1/2006	12/31/2011	800	SCE
GWF Energy, LLC	5/11/2001 Renegotiated on 8/22/02	9/6/2001	12/31/2011	95.8	PG&E
"	"	7/1/2002	12/31/2011	95.8	PG&E
"	"	6/01/2003	10/31/2012	170.5	PG&E
High Desert Power Project	3/9/2001 Renegotiated on 4/22/02	4/22/2003	1/21/2011	Up to 840	SCE
Kings River Conservation District	12/31/2002 Renegotiated on 8/18/04	9/19/2005	9/18/2015	96	PG&E
Mountain View Power Partners, LLC	5/31/2001 Renegotiated on 10/1/02	10/1/2001	9/30/2011	66.6	SCE
Iberdrola Renewables (formerly PPM Energy)	7/6/2001	7/1/2004	6/30/2011	300	PG&E
Sempra Generation	5/4/2001	1/1/2004	9/30/2011	1200	SCE
"	"	1/1/2008	9/30/2011	400	SCE
Sunrise Power Company, LLC	6/25/2001 Renegotiated on 12/31/02	6/01/2003	6/30/2012	572	SDG&E
(Wellhead) Fresno Cogeneration Partners	8/3/2001 Renegotiated on 12/17/02	8/20/2001	10/31/2011	21.5	PG&E
Wellhead Power Gates, LLC	8/14/2001 Renegotiated on 12/17/02	12/27/2001	10/31/2011	46.4	PG&E

		Delivery	Delivery		
	Date	Start	End	Capacity	
Counter-Party	**Executed**	**Date**	**Date**	**MW**	**Allocated**
Wellhead Power Panoche, LLC	8/14/2001 Renegotiated on 12/17/02	12/14/2001	10/31/2011	49.9	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

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

CONTRACT MANAGEMENT AND DISPOSITION ALTERNATIVES

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

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

It is possible that additional power contract modifications, including termination of one or more contracts, could be agreed to between the Department and one or more of its long-term power supply counterparties prior to the end of the 2011 Revenue Requirement Period. As of the date of this Proposed 2011 Revenue Requirement Determination, the Department has not entered into any such final power contract modifications other than as already noted herein.

COST RESPONSIBILITY SURCHARGE

In a series of decisions, the 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 the MOU 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-5 has been reviewed by the Department to determine the costs that will impact its revenue requirements during 2011. All applicable costs are reflected in the Department's electric market simulation along with previously noted operational considerations. The types of costs included in the Department's contract-specific projections include, but are not limited to, fixed energy, capacity, fixed operation and maintenance, variable operation and maintenance, scheduling coordinator fees, and fuel management fees. Total accrued long-term power contract costs, including requisite natural gas purchases, are projected to be $1.695 billion for the 2011 Revenue Requirement Period, as noted in Table D-4. Natural gas costs represent a significant component of the Department's total energy costs and are discussed below in greater detail.

For informational purposes, Table D-7 shows, for the 2011 Revenue Requirement Period, the expected average cost (in $/MWh) on a quarterly basis for the Department's long-term power contracts.

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

	Long-Term Priority Contracts
Quarter 1 – 2011	73
Quarter 2 – 2011	74
Quarter 3 – 2011	78
Quarter 4 – 2011	66

NATURAL GAS PRICE FORECAST AND FUELS ASSUMPTIONS

The natural gas price forecast supporting this Proposed 2011 Determination is based on the NCI Spring 2010 Natural Gas Price Forecast ("NCI Spring 2010 Forecast") Base Case prepared by Navigant Consulting, Inc. ("NCI"), consultants to the Department. Assumptions underlying the NCI Spring 2010 Forecast include all significant supply and demand factors affecting the North American natural gas market such as the timing of major gas pipeline capacity changes, resource base additions and subtractions, gas demand, the price of crude oil, the timing and magnitude of certain liquefied natural gas ("LNG") capacities, imports and exports.

The NCI Spring 2010 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 2011 Determination, the near term monthly prices at Henry Hub were revised on May 1, 2010 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 2010 Determination published October 27, 2009, prices in the NCI/DWR Spring 2010 Forecast Base Case supporting this Proposed 2011 Determination are shown in Table D-8.

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

	2011	**2012**
Gas Price Forecast – Revised 2010 Determination	6.46	5.37
Gas Price Forecast – Proposed 2011 Determination	5.49	5.69
Difference	(0.97)	0.32

Table D-9 below lists the updated natural gas prices by quarter for 2011 and 2012 at two key California market hubs: PG&E Citygate and the Southern California Border.

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

	Southern California Border		**PG&E Citygate**	
	2011	**2012**	**2011**	**2012**
Q1	5.33	6.15	5.92	6.52
Q2	4.93	5.50	5.37	5.88
Q3	5.21	5.48	5.61	5.77
Q4	5.76	5.53	6.13	5.84
Annual Average	**5.31**	**5.67**	**5.76**	**6.00**

GAS HEDGING EXPENSE

For the 2011 Revenue Requirement Period, the Department has reflected the impact of natural gas price hedges on a portion of the projected gas purchases that will be made to support the Department's power contracts. The hedging expenses and projected hedged volume are based on responses to information requests provided by the IOUs in April and May 2010 and monthly activity in the Department's Gas Hedging Account and the Department's own internal analysis.

The Department estimates that as of May 31, 2010, the IOUs had collectively secured, or developed reasonably firm plans to secure, hedges on behalf of DWR that establish the effective price for over 86 million MMBtu during calendar year 2011. The hedged volume represents approximately 64 percent of total projected IOU base case gas requirements (for fuel related to allocated DWR power contracts) for the 2011 Revenue Requirement Period.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR MARKET REDESIGN AND TECHNOLOGY UPGRADE ASSUMPTIONS

The Department's 2011 Revenue Requirement was developed using the same fundamental economic dispatch principles used in past revenue requirements. The CAISO has completed an initiative called Market Redesign and Technology Upgrade ("MRTU") implementing a new day-ahead wholesale electricity market and 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. Financial responsibility with respect to certain CAISO costs associated with the delivery of DWR contract energy to retail customers also needed to be addressed with the IOUs.

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. DWR believes that sufficient certainty has been reached in discussions with counterparties to be able to finalize the specific revisions to the currently effective Servicing Arrangements and the Operating Arrangements needed to reflect the MRTU. In addition, based on actual operating experience of DWR 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. In the near future, DWR expects to provide revisions to the currently effective Servicing Arrangements and the Operating Arrangements to the CPUC for approval. At this time, DWR cannot predict the timeline for approval of the revised Servicing Arrangements and the Operating Arrangements by the CPUC.

To the extent that DWR has not sufficiently identified or implemented new or modified procedures necessary for its internal procedures, including the administration of DWR's power purchase contracts under MRTU, to achieve operating results consistent with current assumptions set forth in the applicable revenue requirement, it could adversely affect the costs related to and associated with the dispatch and operation of DWR's power purchase contracts and DWR's recovery of Power Charges.

ADMINISTRATIVE AND GENERAL COSTS

The Department's administrative and general costs of $27 million consist of $22 million for appropriated budget expenditures including funds for labor and benefits, pro rata charges for services provided to the power supply program by other State agencies and $5 million for consulting services for development and monitoring of the revenue requirements, litigation and dispute resolution support, power contract management, and financial advisory services for managing the $9 billion debt portfolio and related reserves.

FINANCING RELATED ASSUMPTIONS

For purposes of calculating the interest earnings on account balances during 2011, the Department assumes a 1.98 percent earnings rate for the Debt Service Reserve Account and a .48 percent earnings rate for all other accounts during the 2011 Revenue Requirement Period.

The Department currently has $6.390 billion of fixed rate bonds outstanding, $1.053 billion of hedged variable rate bonds outstanding that have corresponding interest rate hedges in place to convert debt service to fixed rate and $0.952 billion of unhedged variable rate debt. The projected average interest rate for all fixed rate bonds for the 2011 Revenue Requirement Period is 4.948 percent. The projected average interest rate for all hedged variable rate bonds (taking into account the hedges) is 4.060 percent.

For purposes of calculating the interest accruing on unhedged variable rate bonds during 2011, 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 2011 Revenue Requirement Period, on the basis of these assumptions, the interest rate on Variable Rate Bonds is projected to be 4.423 percent.

The Department projects that the amount of Bond Charge Revenues required for the 2011 Revenue Requirement Period will be $889 million.

ACCOUNTS AND FLOW OF FUNDS UNDER THE BOND INDENTURE

General information on the Accounts and flow of funds under the Bond Indenture, which has not changed since the bonds were issued in 2002, is contained in the Department's prior

Determinations of Revenue Requirements, copies of which have been incorporated into the administrative record supporting this Determination.

Information specific to certain Accounts for this Proposed 2011 Revenue Requirement Determination follows.

OPERATING ACCOUNT

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

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

For the purposes of this Proposed 2011 Determination, the Department has determined the MOEAB to be $177 million. The Department projects to exceed the MOEAB at all times during 2011. The Department has determined that the amount projected to be on deposit in the Operating Account, including the amount therein that acts as a reserve for Operating Expenses, is just and reasonable, based in part on the following: (1) potential gas price volatility, (2) potential gas price escalation, (3) year-over-year revenue requirement volatility, and (4) credit rating agency and credit and liquidity facility considerations, as well as the factors discussed below under "Sensitivity Analysis" and in Section E—"Key Uncertainties in the Revenue Requirement Determination".

OPERATING RESERVE ACCOUNT

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

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

Based on the Stress Cases described below under "Sensitivity Analysis", the ORAR for the 2011 Revenue Requirement Period is determined by the Department to be $364 million, reflecting an amount equal to 12 percent of the most recent 12 month period of Operating Expenses.

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 2011 Revenue Requirement Period, the Department will calculate projected interest on unhedged Variable Rate Bonds at 4.423 percent.

For the 2011 Revenue Requirement Period, the Department has determined the Debt Service Reserve Requirement to be $941 million. The Department projects to maintain this amount at all times during the Revenue Requirement Period.

SENSITIVITY ANALYSIS

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

CASE 1

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

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

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

	Henry Hub	Southern California Border	PG&E Citygate
	2011	**2011**	**2011**
Q1	8.94	8.91	11.11
Q2	8.47	8.12	10.04
Q3	8.77	8.67	10.50
Q4	9.56	9.79	11.56
Annual Average	8.93	8.87	10.80

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 September 2000 through April 2010 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 May 31, 2010. These hedges, in many instances, limit the price of natural gas purchases under the Stress Cases to levels below the Stress Case gas price forecast for those volumes and time periods for which the hedges are in place.

Lower customer sales by the Department are driven primarily by a decrease in the net short energy requirements, which can occur as a result of increased URG and/or decreased customer load. In this case, URG is increased by assuming California and Pacific Northwest hydroelectric production at 125 percent of normal for 2011 and 2012.

Lower loads are estimated in this case by assuming cooler-than-normal summers during 2011 and 2012, and by assuming increased non-programmatic conservation. The level of decreased customer load due to temperature variation is simulated by decreasing the Base Case total monthly load forecast for 2011 and 2012 by 3.3 percent, 3.6 percent, 5.1 percent and 4.4 percent for June, July, August, and September, respectively. In addition, an increase in the assumed level of non-programmatic conservation (above the Base Case) results in decreases in total annual load of four percent in 2011 and two percent in 2012. Lower electric loads result in a Stress Case for Department revenue because the fixed component of Department energy contracts must be allocated over fewer MWh of retail electric sales, thereby increasing the Department's required recovery cost per MWh.

CASE 2

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

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

Higher customer sales by the Department are driven primarily by an increase in the net short, which can occur as a result of decreased URG and/or increased customer load. In this case, URG is decreased by assuming California and Pacific Northwest hydroelectric production at 75 percent of normal in 2011 and 2012. URG is further decreased by assuming an unplanned outage at one southern California nuclear power plant unit from January 2011 through March 2011 and at one northern California nuclear power plant unit from April 2011 through March 2012. The expected impact of this type of an assumption is to increase the amount of energy dispatched from the Long-Term Priority Contracts.

Higher loads are estimated in this case by assuming load growth rates that are 2.0 percentage points higher than those assumed in the Base Case in 2011 and 1.4 percent higher in 2012. It is assumed that this growth occurs as a result of the combination of accelerated economic growth in California and decreases in the expected amount of achieved non-programmatic conservation. In addition, load is increased by assuming the existence of warmer-than-normal summers in 2011 and 2012. The level of increased customer load due to temperature variation is simulated by increasing the Base Case total monthly load forecast (inclusive of the accelerated growth rates described above) in 2011 and 2012 by 4.4 percent, 4.8 percent, 6.8 percent, and 5.9 percent for June, July, August, and September, respectively.

E. POWER CONTRACT SETTLEMENT SUMMARY

The California Parties, which include the Governor's Office, California Attorney General's Office, CPUC, the Department and the IOUs (collectively with DWR, the "Settling Parties") 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, all outstanding claims against Sempra by the Settling Parties related to the energy crisis will be dismissed with prejudice.

The $400 million cash amount will be allocated as determined by the Settling Parties. Under the terms of the proposed 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.

Any settlement distributions from the proposed settlement with Sempra and any other settlements will reduce Department costs and, as a result, decrease the Department's 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 requirements for the 2011 Revenue Requirement Period after this Proposed 2011 Determination. Several risk factors are outlined below and additional information may be found in each of the bond financing Official Statements, which may be obtained from the Treasurer of the State of California

1. Determination of Power Charges and Bond Charges; possible use of amounts in the Bond Charge Collection Account to pay Priority Contract Costs:
    a. Potential administrative and legal challenges to DWR's revenue requirements;

   b. Potential litigation regarding inclusion of DWR Priority Contract Costs in its Retail Revenue Requirement; and
   c. Application and enforcement of the Rate Agreement's Bond Charge rate covenant.

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

3. Certain risks associated with DWR's Power Supply Program:
   a. Long-term power contracts:
      i. Impact of renegotiated contracts;
      ii. 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;
   b. Dispatch coordination between IOUs and DWR; and

7. Uncertainties relating to electric industry and markets:
   a. Electric transmission constraints;
   b. Gas transmission constraints; and

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 DWR-CERS website by interested persons, and the supporting materials are available at the CERS office in Sacramento, subject to applicable non-disclosure requirements.

Determination	Date Issued
2001-2003, including Reexamination and Redetermination for 2001-2002	August 16, 2002
Reconsideration of Just and Reasonableness of 2001 - 2003	August 19, 2004
2003 Supplemental	July 1, 2003
2004	September 18, 2003
2004 Supplemental	April 16, 2004
2005	November 4, 2004
Revised 2005	March 16, 2005
2006	August 3, 2005
Final 2006	October 27, 2005
2007	August 2, 2006
Revised 2007	October 30, 2006
2008	August 22, 2007
Revised 2008	October 31, 2007
Supplemental 2008	February 15, 2008
2009	August 6, 2008
Revised 2009	October 29, 2008
2010	August 6, 2009
Revised 2010	October 27, 2009

THE PROPOSED 2011 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, 2011, through December 31, 2011 for public review and comment under the Regulations promulgated pursuant to the California Administrative Procedures Act. Under the Regulations, any determination that this Proposed 2011 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 2011 that differs from this Proposed 2011 Determination.

H. MARKET SIMULATION

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

As part of its market report and simulation in developing the 2011 Revenue Requirement, the Department considered all items in the above paragraph and the following:

- California ISO Market Redesign and Technology Upgrade implemented in April, 2009;
- Potential impacts of market redesign on the Department's long-term contracts and revenue requirements;
- Use of PROMOD as a market simulation tool;
- Analysis of retirement and additions of WECC generation resources; and
- California ISO Locational Marginal Price and Congestion Revenue Rights proposals.

More detailed information about the market simulation utilized by the Department, including descriptions of the inputs and assumptions is referenced in Section J of the 2008 Revenue Requirement[6].

[6] Volume DWR08pRR, Record Number 022, dated 4/10/2007.

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

Volume	Record Number	Date	Record Title
DWR11pRR	001	10/11/09	Senate Bill 695
DWR11pRR	002	10/27/09	Revised Revenue Requirement Determination for 2010, including the Revised Determination, The Notice, and the Transmittal letter from CERS to the Commission
DWR11pRR	003	11/18/09	ACR's 11/18/09 Ruling in R07-05-025 on Procedures to Address Senate Bill 695 Issues Relating to Direct Access Transactions
DWR11pRR	004	12/03/09	Decision 09-12-005: "Decision Allocating The Revised 2010 Revenue Requirement Determination Of The California Department Of Water Resources"
DWR11pRR	005	12/04/09	ALJ ruling regarding the date of issuance of Decision 09-12-005 and shortening of time for responses to any application for rehearing.
DWR11pRR	006	12/04/09	MEA Implementation Plan
DWR11pRR	007	12/11/09	SCE Advice Letter 2416-E: Implementation of the 2010 California Department of Water Resources Power and Bond Charges in Accordance With Decision 09-12-005
DWR11pRR	008	12/14/09	SDG&E Advice Letter 2132-E: Revisions To The DWR Power Charge And DWR Bond Charge Pursuant To D.09.12.005
DWR11pRR	009	12/14/09	PG&E Advice Letter 3576-E: 2010 Department of Water Resources Revenue Requirement Determination in compliance with D.09-12-005
DWR11pRR	010	2/17/10	DWR Electric Power Fund Financial Statements, 12/31/09
DWR11pRR	011	3/11/10	Decision 10-03-022: "Decision Regarding Increased Limits for Direct Access Transactions"
DWR11pRR	012	3/29/10	DWR "Russell Mills" email to PG&E, SCE, and SDG&E advising of near-term kickoff of 2011 Revenue Requirement Process
DWR11pRR	013	4/7/10	NCI "Kreg McCollum" email transmittal of Data Request 1 to PG&E, SCE, and SDG&E
DWR11pRR	014	4/7/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E preliminary response item one re: DWR Data Request 1
DWR11pRR	015	4/9/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E preliminary response item two re: DWR Data Request 1
DWR11pRR	016	4/9/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E preliminary response item three re: DWR Data Request 1
DWR11pRR	017	4/13/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E preliminary response item four re: DWR Data Request 1
DWR11pRR	018	4/15/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E response to DWR Data Request 1, Questions 1 and 8
DWR11pRR	019	4/16/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR

			response to SDG&E question re: DWR reserves
DWR11pRR	020	4/16/10	NCI "Kreg McCollum" email transmittal of Revised Data Request 1 to PG&E, SCE, and SDG&E
DWR11pRR	021	4/19/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR response to SDG&E question re: hedging
DWR11pRR	022	4/20/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E revised response to DWR Data Request 1, Question 7 (original Question 8)
DWR11pRR	023	4/20/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE response to DWR Data Request 1, Question 7
DWR11pRR	024	4/22/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR response to SCE Data Request question
DWR11pRR	025	4/23/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE response to DWR Data Request 1, Questions 1-6
DWR11pRR	026	4/26/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E response to DWR Data Request 1, Questions 1-6
DWR11pRR	027	4/26/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E response to DWR Data Request 1, Questions 2-6
DWR11pRR	028	4/30/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E response to DWR Data Request 1, Question 7
DWR11pRR	029	4/30/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Data Request 1 Clarification Questions to SDG&E
DWR11pRR	030	4/30/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Data Request 1 Clarification Questions to SCE
DWR11pRR	031	5/3/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E response to DWR Data Request Questions
DWR11pRR	032	5/5/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR-PG&E email series re: DWR questions on PG&E Data Response
DWR11pRR	033	5/5/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR-PG&E email series re: DWR questions on PG&E Data Response
DWR11pRR	034	5/5/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR-PG&E email series re: DWR questions on PG&E Data Response
DWR11pRR	035	5/5/10	Bond Refinancing Offering Statement, Series 2010L
DWR11pRR	036	5/10/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: NCI "Kreg McCollum" email with DWR Preliminary Dispatch and Contract Estimates - SCE
DWR11pRR	037	5/10/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: NCI "Kreg McCollum" email with DWR Preliminary Dispatch and Contract Estimates – SDG&E
DWR11pRR	038	5/10/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: NCI "Kreg McCollum" email with DWR Preliminary Dispatch and Contract Estimates – PG&E
DWR11pRR	039	5/11/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR – PG&E email series re. Preliminary Dispatch, Contract Estimates and Fuel costs
DWR11pRR	040	5/17/10	DWR Electric Power Fund Financial Statements, 3/31/10

DWR11pRR	041	5/21/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Spring 2010 Base Case and Stress Case Gas Price Forecast
DWR11pRR	042	5/24/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR – PG&E email series re. additional DWR questions on PG&E generation
DWR11pRR	043	5/25/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR – PG&E email series re. additional DWR questions on PG&E bilaterals
DWR11pRR	044	5/26/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E responses to further DWR questions on PG&E bilaterals
DWR11pRR	045	5/27/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Data Request 2 to PG&E
DWR11pRR	046	5/31/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PROMOD 17 Base and Stress Case Results
DWR11pRR	047	6/1/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E response to DWR Data Request 2
DWR11pRR	048	6/8/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: Financial Model (CFMG5V26ab--2011 RR filing 2010-06-09.xlsProjection of Revenue Requirements
DWR11pRR	049	6/8/10	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: Fuel Hedging Workpaper