**State of California**

**Department of Water Resources**

# Proposed
# Determination of Revenue Requirements

**For the Period**

**January 1, 2010 through December 31, 2010**

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

**August 6, 2009**

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# A. THE 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 Determination of Revenue Requirements for the period January 1, 2010 through December 31, 2010 ("2010 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 2010 Determination contains information on the amounts required to be recovered, on a cash basis, in the 2010 Revenue Requirement Period (calendar year 2010).

For the 2010 Revenue Requirement Period, this 2010 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

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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 2010 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.

projected amount of Bond Charges required to be collected for such purpose; and (c) the amount needed to pay the Department's costs, including all Retail Revenue Requirements.

## DETERMINATION OF REVENUE REQUIREMENTS

Pursuant to the Act, the Rate Agreement and the Regulations, the Department determines, on the basis of the materials presented and referred to by this 2010 Determination (including the materials referenced in Section J), that its cash basis revenue requirement for 2010 is $3.185 billion, consisting of $2.248 billion in Power Charges and $0.937 billion in Bond Charges.

This 2010 Determination takes into account preliminary actual operating results through May 2009.

Any net surpluses or deficiencies during the 2009 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 2010 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 2010. These figures are compared to those reflected in the Department's final 2009 revenue requirement determination, as reflected in the Department's Revised 2009 Determination of Revenue Requirements for the period of January 1, 2009 through and including December 31, 2009 (as so reflected, the "Revised 2009 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 2010 POWER CHARGE REVENUE REQUIREMENTS AND POWER CHARGE ACCOUNTS AND COMPARISON TO 2009[1]
# ($ Millions)

| Line | Description | 2010[2] | 2009[3] | Difference |
|---|---|---|---|---|
| 1 | *Beginning Balance in Power Charge Accounts* | | | |
| 2 | Operating Account | 1,134 | 870 | 264 |
| 3 | Priority Contract Account | - | - | - |
| 4 | Operating Reserve Account | 543 | 548 | (5) |
| 5 | **Total Beginning Balance in Power Charge Accounts** | **1,677** | **1,418** | **259** |
| 6 | *Power Charge Accounts Operating Revenues* | | | |
| 7 | Power Charge Revenues[4] | 2,248 | 3,551 | (1,303) |
| 8 | Other Revenue[5] | - | 55 | (55) |
| 9 | Interest Earnings on Fund Balances | 20 | 36 | (16) |
| 10 | **Total Power Charge Accounts Operating Revenues** | **2,268** | **3,642** | **(1,375)** |
| 11 | *Power Charge Accounts Operating Expenses* | | | |
| 12 | Administrative and General Expenses | 26 | 28 | (1) |
| 13 | Total Power Costs[6] | 2,850 | 3,691 | (841) |
| 14 | **Total Power Charge Accounts Operating Expenses** | **2,876** | **3,718** | **(843)** |
| 15 | Net Operating Revenues | (608) | (76) | (532) |
| 16 | **Ending Aggregate Balance in Power Charge Accounts** | **1,069** | **1,341** | **(273)** |

| 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. | 195 | 331 | (135) |
| **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. | 529 | 543 | (14) |
| **Total Operating Reserves**: | 724 | 874 | (149) |

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the 2009 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]See Surplus Sales discussion herein
[6]Includes gas hedging and collateral amounts.

## TABLE A-2
## SUMMARY OF THE DEPARTMENT'S 2010 BOND CHARGE REVENUE REQUIREMENTS AND BOND CHARGE ACCOUNTS AND COMPARISON TO 2009[1]
## ($ Millions)

| Line | Description | 2010[2] | 2009[3] | Difference |
|---|---|---|---|---|
| 1 | *Beginning Balance in Bond Charge Accounts* | | | |
| 2 | Bond Charge Collection Account | 171 | 241 | (70) |
| 3 | Bond Charge Payment Account | 656 | 630 | 26 |
| 4 | Debt Service Reserve Account | 950 | 917 | 33 |
| 5 | **Total Beginning Balance in Bond Charge Accounts** | **1,778** | **1,788** | **(11)** |
| 6 | *Bond Charge Accounts Revenues* | | | |
| 7 | Bond Charge Revenues from Utiltities[4] | 937 | 858 | 78 |
| 8 | Interest Earnings on Fund Balances | 33 | 55 | (22) |
| 9 | **Total Bond Charge Accounts Revenues** | **969** | **913** | **56** |
| 10 | *Bond Charge Accounts Expenses* | | | |
| 11 | Debt Service on Bonds[5] | 975 | 945 | 30 |
| 12 | **Total Bond Charge Accounts Expenses** | **975** | **945** | **30** |
| 13 | Net Bond Charge Revenues | (6) | (32) | 26 |
| 14 | **Ending Aggregate Balance in Bond Charge Accounts** | **1,772** | **1,757** | **15** |

| 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 | 81 - 83 | 78 - 80 | 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 | 338 - 913 | 328 - 873 | Different |
| **Debt Service Reserve Account**: Established as the maximum annual debt service | 980 | 950 | 30 |

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the 2009 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 2010 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, the direct access rulemaking which concluded in D.08-02-033 that there is merit in considering ways to relieve DWR of its obligations to supply power on an expedited basis by facilitating negotiations with DWR contract counterparties to enter into replacement agreements with the investor-owned utilities (IOUs), 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 events, 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 2009

On July 8, 2008, the Department issued its Proposed Determination of Revenue Requirements for 2009, 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 29, 2008.

On August 6, 2008, the Department published its Determination of Revenue Requirements for the period of January 1, 2009 through and including December 31, 2009 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, 2008 Determination just and reasonable.

The Department reviewed certain matters relating to its August 6, 2008 Determination, including, but not limited to, operating results of the Electric Power Fund (the "Fund") as of September 30, 2008 (the August 6, 2008 Determination incorporated preliminary actual operating results through June 2008); and an updated gas price forecast.

On October 17, 2008, the Department issued its Proposed Revised Determination of Revenue Requirements for 2009 (the "Proposed Revised Determination"), consistent with the requirements of Sections 80110 and 80134 of the California Water Code, and provided information consistent with the Regulations. The Department provided interested persons with quantitative results from its PROMOD market simulation and Financial Model, subject to applicable non-disclosure requirements. Interested persons were advised to submit comments no later than October 24, 2008.

On October 29, 2008 the Department published its revised Determination under Section 516 of the Regulations addressing the following matters:

**1)** Updated the preliminary actual Electric Power Fund operating results through September 30, 2008.
**2)** Updated natural gas price forecasts and related assumptions.
**3)** Updated modeling assumptions and operational considerations provided by the IOUs pertaining underlying assumptions incorporated into the PROMOD IV market simulation model.
**4)** Updates to the projections of operating balances for 2010 and 2011, relative to those calculated in the October 17, 2009 Proposed Revised Determination.
**5)** Updates, relative to the October 17, 2009 Proposed Revised Determination, to the projection of Power Charges for 2009 considering the Department's determination of the minimum Operating Account balance projection in 2010.
**6)** Updated actual variable rate interest results through September 30, 2008

These revisions resulted in a total decrease in the Revised 2009 Determination of $480 million relative to the August 6, 2008 Determination. This decrease was comprised of two components: a $509 million decrease in the Department's Power Charge Revenue Requirement; and a $29 million increase in the Department's Bond Charge Revenue Requirement.

The $509 million Power Charge Revenue Requirement decrease primarily resulted from (1) the net effects of a decrease in contract costs due to a decrease in the gas price forecast for 2009 and (2) the changes to the Operating Account and Operating Reserve Balances for 2010 and 2011. The $29 million Bond Charge Revenue Requirement increase primarily resulted from the net effects of an increase in the projections of interest rates for the unhedged variable rate portion of the Department's bond portfolio.

## THE 2010 DETERMINATION

The Department sent requests for information to each IOU on April 9, 2009, 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 the Proposed 2010 Determination published on June 18, 2009. 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 changes relating to Commission rulings addressing the allocation of contract costs and the sharing of revenues from wholesale sales of contract generation volumes. The resulting data was incorporated into the PROMOD IV market simulation model, and became a part of the projections leading to the Proposed Determination.

The Department provided interested persons with quantitative results from its PROMOD market simulation and Financial Model, subject to applicable non-disclosure requirements. Interested parties were advised to submit comments no later than July 9, 2009.

Southern California Edison Company ("SCE"), San Diego Gas and Electric Company ("SDG&E) and the Alliance for Retail Energy Markets ("AReM") submitted comments. The comments were considered by the Department prior to this 2010 Determination. The comments are summarized and the Department's responses are included in Section I.

After review of all comments, the Department has made the following changes in this 2010 Determination:

**1)** Based on clarifications provided by SDG&E, the load forecast for SDG&E used in this Determination has been revised. The revision of loads provided by SDG&E does not have an impact on the dispatch of regional resources, but it does have an impact on the level of customer sales and wholesale sales from the DWR contracts allocated to SDG&E.

The change to SDG&E's load forecast did not change the Power Charge and Bond Charge revenue requirements.

## C. THE DEPARTMENT'S DETERMINATION OF REVENUE REQUIREMENTS FOR THE PERIOD JANUARY 1, 2010 THROUGH DECEMBER 31, 2010

### REVENUE REQUIREMENT DETERMINATION

For 2010, 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 2010, the Department projects that it will incur the following power procurement-related Costs: (a) $2.850 billion for long-term power contract purchases to cover the net short requirement of customers; (b) $26 million in administrative and general expenses; and (c) $(608) million in other net changes to Power Charge Accounts (including operating reserves). This projection results in a revenue requirement of $2.268 billion.

Funds to meet these costs (in addition to surplus operating reserves) are projected to be provided from (a) $20 million of interest earned on Power Charge Account balances; and (b) $2.248 billion from Power Charge Revenues and Cost Responsibility Surcharge ("CRS") revenues from customers other than customers of the IOUs and DWR.

Table C-1 provides a quarterly projection of costs and revenues associated with the Power Charge Accounts for the 2010 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 | | | | |
|---|---|---|---|---|---|---|
| | | Q1 | Q2 | Q3 | Q4 | Total |
| 0 | *Power Charge Accounts Expenses* | | | | | |
| 1 | Power Costs | 725 | 631 | 779 | 715 | 2,850 |
| 2 | Administrative and General Expenses | 7 | 7 | 7 | 7 | 26 |
| 3 | Net Changes to Power Charge Account Balances | (41) | (140) | (242) | (186) | (608) |
| 4 | **Total Power Charge Accounts Expenses** | **691** | **498** | **543** | **536** | **2,268** |
| 5 | *Power Charge Accounts Revenues* | | | | | |
| 6 | Interest Earnings on Power Charge Account Balances | 5 | 5 | 5 | 4 | 20 |
| 7 | Operating Account Balance Adjustment | - | - | - | - | - |
| 8 | Total Power Charge Revenue Requirement | 686 | 492 | 538 | 531 | 2,248 |
| 9 | **Total Power Charge Accounts Revenues** | **691** | **498** | **543** | **536** | **2,268** |

During 2010, the Department projects that it will incur the following Bond Related Costs: (a) $975 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) $(6) million for changes to Bond Charge Account balances, resulting in total Bond Charge Account expenses of $969 million.

Funds to meet these requirements are provided from (a) $33 million in interest earned on Bond Charge Account balances, and (b) $937 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 2010 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 | 56 | 697 | 57 | 165 | 975 |
| 2 | Net Changes to Bond Charge Account Balances | 161 | (464) | 205 | 93 | (6) |
| 3 | **Total Bond Charge Accounts Expenses** | **216** | **233** | **262** | **258** | **969** |
| 4 | *Bond Charge Accounts Revenues* | | | | | |
| 5 | Interest Earnings on Bond Charge Account Balances | 4 | 13 | 4 | 12 | 33 |
| 6 | Retail Customer Bond Charge Revenue Requirement | 212 | 220 | 258 | 246 | 937 |
| 7 | **Total Bond Charge Accounts Revenues** | **216** | **233** | **262** | **258** | **969** |

In aggregate, the Department's total cash basis expenses are projected to be $3.851 billion. Revenues from interest earned are projected to be $53 million, and net changes in fund balances are projected to be $(614) million, resulting in combined customer revenue requirements of $3.185 billion.

## D. ASSUMPTIONS GOVERNING THE DEPARTMENT'S PROJECTION OF REVENUE REQUIREMENTS FOR THE 2010 REVENUE REQUIREMENT PERIOD

The Department based this 2010 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 2009 and received further clarification from SDG&E regarding their retail energy forecasts in June and July 2009. 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 2010 energy requirements forecast (quantified in gigawatt hours) for the PG&E, SCE and SDG&E service areas during 2010.

**TABLE D-1**
**ESTIMATED ANNUAL ENERGY REQUIREMENTS**

| Service Area | Total Retail Requirements | Direct Access and CCA Requirements | Bundled Requirements |
|---|---|---|---|
| **Pacific Gas & Electric** | 93,359 | 6,442 | 86,917 |
| **Southern California Edison** | 93,572 | 9,036 | 84,536 |
| **San Diego Gas & Electric** | 21,933 | 3,440 | 18,494 |
| **Total** | 208,864 | 18,918 | 189,946 |

## DIRECT ACCESS

The Department's direct access estimates are based on data provided by each IOU in April 2009 and a review of monthly direct access reports produced by the Commission. The Department notes a slow but steady decline in direct access loads since the Commission suspended the right of bundled customers to elect direct access service, effective September 20, 2001. The

Department regularly reviews each utility's monthly report to the Commission on current direct access load and service request changes to identify any substantive developments that would require Departmental action.

While the option to elect direct access service is suspended until the Department no longer supplies power under Division 27 of the Water Code (see California Water Code § 80110), the Commission initiated a Rulemaking (R. 07-05-025) to evaluate lifting the suspension of direct access prior to 2015 when the last long-term contract is presently scheduled to expire[3]. The Commission states that it expects the proceeding to last longer than eighteen months. Given the manifold issues and the timing of the proceeding, the Department does not project that the suspension of direct access will be lifted during the 2010 Revenue Requirement period.

Table D-2 shows each IOU's direct access forecast, as a percentage of total retail loads, for 2010.

**TABLE D-2**
**2010 DIRECT ACCESS FORECAST[4]**

| Service Area | Percent of Retail Load |
|---|---|
| Pacific Gas & Electric | 6.43% |
| Southern California Edison | 9.55% |
| San Diego Gas & Electric | 15.68% |
| **Total** | **8.80%** |

## COMMUNITY CHOICE AGGREGATION

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

At present no load has left bundled utility service to form or become part of a Community Choice Aggregator pursuant to AB 117. However, the San Joaquin Valley Power Authority (SJVPA) filed an Implementation Plan with the CPUC in January 2007 to become a Community Choice Aggregator. That plan was certified by the CPUC in May 2007. Based on SJVPA's CCA Implementation Plan Modification #3, dated February 2009, SJVPA is expected to eventually serve over 2,500 GWh of load to eleven cities and one county. SJVPA's plans to phase in its Community Choice Aggregation program have been delayed. As a result of these delays, SJVPA is currently expected to phase in approximately 494 GWh of load in 2010, with additional load served in 2011. The SJVPA Community Choice Aggregation load, if implemented, will reduce bundled load in both PG&E's service territory and SCE's service territory.

[3] Peevey Proposed Decision April 24, 2007, Order Granting Petition for Rulemaking and Instituting Rulemaking as to Whether, When, or How Direct Access Should be Restored.
[4] Figures in Table D-2 represent direct access as a percentage of total retail loads for 2010. These percentages correspond to direct access loads forecast by the IOUs in 2009.
[5] Public Utilities Code, Section 331.1(a).

Other communities have indicated an interest in pursuing CCA, including the City and County of San Francisco, several East Bay cities, the City of Chula Vista, Marin County, and the City of Fresno. Because the Department estimates that the process for aggregators to initiate feasibility studies and ultimately procure power on behalf of load to be eighteen to twenty-four months, we do not expect any load from these communities to migrate under the CCA program during the 2010 Revenue Requirement Period.

## POWER SUPPLY RELATED ASSUMPTIONS

In this 2010 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.[6]

Table D-3 below shows, for the 2010 Revenue Requirement Period, the estimated energy requirements for the customers of the IOUs, estimated supplies from generation by the three IOUs,[7] the resulting net short, the expected supply from the Department's long-term power contracts, off-system energy sales and the residual net short.

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

| | **Amount for the Revenue Requirement Period (GWH)** |
|---|---|
| **All Investor-Owned Utilities** | |
| Energy Requirements After Adjustments | 184,736 |
| Supply from Utility Resources | 132,158 |
| Net Short | 52,578 |
| Supply from the Department's Priority Long-Term Power Contracts | 34,853 |
| Off-System Sales | (6,972) |
| Residual Net Short (Surplus) | 24,696 |

Table D-4 shows, on a quarterly basis for the 2010 Revenue Requirement Period, estimated net short volumes in gigawatt-hours, supply from the Department's long-term power contracts and the residual net short.

6 While the Department has calculated and presented the residual net short requirements of the IOUs, pursuant to the Act, the Department has not made any provision for the cost of the residual net short requirements in its Determination for the 2010 Revenue Requirement Period. For purposes of this 2010 Determination, the residual net short for each IOU equals the projected amount of wholesale energy remaining to be procured by such IOU on behalf of ratepayers in its service area.

7 For purposes of this 2010 Determination, generation retained by the three IOUs is defined as the sum of generation owned by the IOUs, interruptible load, supply from contracts between the IOUs and qualifying facilities ("QFs") and other bilateral contracts.

**TABLE D-4**
**NET SHORT, SUPPLY FROM THE DEPARTMENT'S LONG-TERM POWER CONTRACTS AND RESIDUAL NET SHORT IN 2010**

| | Net Short (GWH) | Supply from Power Contracts (GWH) | Off-System Sales Volumes (GWH) | (Residual Net Short) Spot Volume (GWH) |
|---|---|---|---|---|
| Q1-2010 | 12,452 | 8,642 | (1,536) | (5,346) |
| Q2-2010 | 9,817 | 8,418 | (3,318) | (4,718) |
| Q3-2010 | 14,365 | 9,259 | (1,456) | (6,562) |
| Q4-2010 | 15,944 | 8,534 | (661) | (8,071) |
| **Total** | 52,578 | 34,853 | (6,972) | (24,696) |

## UTILITY RESOURCES

The Department reviewed each utility's 2010 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 2010 and 2011. Neither the CEC nor the National Weather Service Northwest River Forecast Center has provided meaningful forecasts past the 2009 water year. Therefore, DWR has projected normal hydroelectric dispatch for the 2010 Revenue Requirement Period.

## CONTRACT ASSUMPTIONS

During the 2010 Revenue Requirement Period, approximately 34,853 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 are expected to be operational during the 2010 Revenue Requirement Period and beyond, describing the term and capacity associated with each contract and the IOU to which the contract has been allocated.

One contract is scheduled to expire during 2009. A 1,000 MW fixed price contract, delivered at all hours of the year (seven days per week, 24 hours per day), with Calpine Energy Services, L.P. (referred to in previous Determinations as "Calpine 1") is scheduled to expire on December 31, 2009.

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

**TABLE D-5**
**LONG-TERM POWER CONTRACT LISTING**

| Counter-Party | Date Executed | Delivery Start Date | Delivery End Date | Capacity MW | Allocated |
|---|---|---|---|---|---|
| **Alliance Colton, LLC** | 4/23/2001 Renegotiated on 9/19/02 | 8/1/2001 | 12/31/2010 | 80 | SCE |
| **BE CA, LLC (formerly Bear Energy, formerly Williams Energy)** | 2/16/2001 Renegotiated on 11/11/02 | 1/1/2008 | 12/31/2010 | 275 | SDG&E |
| " | " | 7/1/2003 | 12/31/2010 | 50 | SDG&E |
| " | " | 1/1/2008 | 12/31/2010 | 1045 | SCE |
| **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 | 2/12/2001 | 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 | 12/31/2009, buyer option to extend to 12/31/2012 | 180 | PG&E |
| **Calpine Energy Services, L.P. (Peaking Capacity)** | 2/27/2001 Renegotiated on 4/22/02 | 8/1/2002 | 7/31/2011 | 495 | PG&E |

| Counter-Party | Date Executed | Delivery Start Date | Delivery End Date | Capacity MW | Allocated |
|---|---|---|---|---|---|
| **Coral Power, LLC** | 5/24/2001 | 1/1/2006 | 6/30/2010 | 400 | PG&E |
| " | " | 7/1/2010 | 6/30/2012 | 100 | PG&E |
| " | " | 7/1/2002 | 6/30/2012 | 100 | PG&E |
| " | " | 7/1/2003 | 6/30/2012 | 175 | PG&E |
| " | " | 7/1/2004 | 6/30/2012 | 175 | PG&E |
| **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 | 3/31/2011 | 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 |
| **City/County of San Francisco** | 12/30/2002 | unknown | unknown | Est. 192 | PG&E |
| **Sempra Energy Resources** | 5/4/2001 | 1/1/2004 | 9/30/2011 | 1200 | SCE |
| " | " | 1/1/2008 | 9/30/2011 | 400 | SCE |
| **Sunrise Power Company, LLC** | 6/25/2001 Renegotiated on 12/31/02 | 6/01/2003 | 6/30/2012 | 572 | SDG&E |
| **Fresno Cogeneration Partners (Wellhead Fresno)** | 8/3/2001 Renegotiated on 12/17/02 | 8/20/2001 | 10/31/2011 | 21.5 | PG&E |

| Counter-Party | Date Executed | Delivery Start Date | Delivery End Date | Capacity MW | Allocated |
|---|---|---|---|---|---|
| **Wellhead Power Gates, LLC** | 8/14/2001 Renegotiated on 12/17/02 | 12/27/2001 | 10/31/2011 | 46.4 | PG&E |
| **Wellhead Power Panoche, LLC** | 8/14/2001 Renegotiated on 12/17/02 | 12/14/2001 | 10/31/2011 | 49.9 | PG&E |
| **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 2010 Revenue Requirement Period. As of the date of this 2010 Revenue Requirement Determination, the Department has not entered into any such final power contract modifications other than as already noted herein.

Currently, in conjunction with the Direct Access rulemaking the CPUC, IOUs and the Department are considering ways to relieve DWR of its obligations to supply power on an expedited basis by facilitating negotiations with DWR contract counterparties to enter into replacement agreements with the IOUs.

If any of the current power contacts are modified, successfully novated or terminated, the Department will determine if a revision of its revenue requirement is warranted. It would prepare a revision based on the remaining power contract portfolio and the operating reserves will, as always, be based on provisions in the Bond Indenture

Finally, the Department's power contracts were executed prior to MRTU, and have terms and conditions that were not drafted in anticipation of the implementation of MRTU. With the implementation of MRTU on April 1, 2009 – which significantly changes the way energy is scheduled and settled – several proposals to amend most of the Department's existing contracts with electric generators and power marketers are being considered and may be implemented.

## 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

The IOUs and the Department, after consideration of the Market Redesign and Technology Upgrade by the California Independent System Operator which went into effect on April 1, 2009, jointly submitted a motion 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 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 will no longer be used to offset DWR's revenue requirement, but rather DWR will receive remittances based all energy dispatched from DWR contracts in each IOU service area, which will be deemed delivered to retail customers. Customers will remit power charges in amounts that will enable the recovery of ongoing operating costs of the Department's power supply program.

The CPUC granted the Joint Motion on March 13, 2009 as part of Rulemaking 06-07-010. Currently the IOUs and DWR are abiding by the remittance processes described in its joint motion. Specific contract remittance details and procedures are described in a Memorandum of Understanding ("MOU") that was attached to the Joint Motion.

The IOUs and the Department are collaborating on formalizing the MOU by filing a request to the CPUC to modify the applicable Servicing Orders, Operating Order, and Operating Agreements in the near future.

## 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 2010. 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 $2.809 billion for the 2010 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-7 shows, for the 2010 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 – 2010 | 76 |
| Quarter 2 – 2010 | 77 |
| Quarter 3 – 2010 | 82 |
| Quarter 4 – 2010 | 80 |

## NATURAL GAS PRICE FORECAST AND FUELS ASSUMPTIONS

The natural gas price forecast supporting this 2010 Determination is based on the NCI Spring 2009 Natural Gas Price Forecast ("NCI Spring 2009 Forecast") Base Case prepared by Navigant Consulting, Inc. ("NCI"), consultants to the Department. Assumptions underlying the NCI Spring 2009 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 2009 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 2010 Determination, the near term monthly prices at Henry Hub were revised on April 23, 2009 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 2009 Determination published October 29, 2008, prices in the NCI/DWR Spring 2009 Forecast Base Case supporting this 2010 Determination are shown in Table D-8.

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

| | **2010** | **2011** |
|---|---|---|
| Gas Price Forecast – Proposed 2010 Determination | 5.95 | 6.37 |
| Gas Price Forecast – Revised 2009 Determination | 9.18 | 9.41 |
| **Difference** | (3.23) | (3.04) |

Table D-9 below lists the updated natural gas prices by quarter for 2010 and 2011 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** | |
|---|---|---|---|---|
| | **2010** | **2011** | **2010** | **2011** |
| Q1 | 5.67 | 6.83 | 5.88 | 7.03 |
| Q2 | 5.45 | 6.22 | 5.76 | 6.30 |
| Q3 | 5.76 | 6.05 | 6.06 | 6.07 |
| Q4 | 6.29 | 5.74 | 6.68 | 5.88 |
| **Annual Average** | **5.79** | **6.21** | **6.10** | **6.32** |

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

During the 2010 Revenue Requirement Period, it is projected that the Natural Gas Purchase Contract will result in power cost savings of approximately $23 million, based on the difference between the contract fuel price of $4.39 and the Department's projected average fuel price of $5.79 at the Southern California Border pricing hub. For the purpose of determining power cost savings related hereto, the weighted average fuel price considered in this analysis accounts for related, seasonal variations in both the base case fuel price forecast and fuel volumes delivered under the Williams Natural Gas Purchase Contract in 2010.

## GAS HEDGING EXPENSE

For the 2010 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 2009 and monthly activity in the Department's Gas Hedging Account and the Department's own internal analysis.

The Department estimates that as of May 30, 2009, the IOUs had collectively secured, or developed reasonably firm plans to secure, hedges on behalf of DWR that establish the effective price for over 116 million MMBtu during calendar year 2010. The hedged volume represents approximately 56 percent of total projected IOU base case gas requirements (for fuel related to allocated DWR power contracts) for the 2010 Revenue Requirement Period. The Department has effectively hedged 18 million MMBtu of natural gas via firm price deliveries from the Williams contract during both the 2010 Revenue Requirement Period, and this annual volume is included in the aforementioned 116 million MMBtu for 2010.

## CALIFORNIA INDEPENDENT SYSTEM OPERATOR MARKET REDESIGN AND TECHNOLOGY UPGRADE ASSUMPTIONS

The Department's 2010 Revenue Requirement was developed using the same fundamental economic dispatch principles used in past revenue requirements. The CAISO implemented their Market Redesign and Technology Upgrade in April 2009. MRTU changes the way in which energy is scheduled and settled, and is based on a nodal, as opposed to zonal, delivery point and pricing structure.

Some uncertainty exists with respect to the operation of the power contracts and remittance procedures of the IOUs and the Department. To address such uncertainty the IOUs and the Department jointly submitted a motion to the CPUC that clarified the process that the IOUs will use to remit power charges to DWR. Attached to the Joint Motion was a Memorandum of Understanding ("MOU") that described, as specifically as is possible at that time, the agreed-upon operation and remittance procedures - that will require amendments to the operating and servicing order/agreements- which the IOUs and DWR have been operating under since April 1, 2009.

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 will no longer be used to offset DWR's revenue requirement, but rather DWR will receive remittances based on all energy dispatched from DWR contracts in each IOU service area, which will be deemed delivered to retail customers. Customers will remit power charges in amounts that will enable the recovery of ongoing operating costs of the Department's power supply program.

With regards to the bidding and operations of the Power Contracts, the MOU contains contract tables which outline the expected bidding and operations methodologies and remittance basis for contracts allocated to each of the three IOUs. The new methodologies take into account the creation of a day-ahead market under MRTU as well as a settlement mechanism created to avoid potential double payments to the generators.

The implementation of MRTU did not substantially change the 2009 DWR power charge revenue requirement. Likewise MRTU is not expected to materially change the 2010 Revenue Requirement. The Joint Motion – which was approved by the CPUC on March 13, 2009 - is intended solely to ensure that the customers in each IOU service area continue to remit power charges in reasonable amounts that cover the ongoing operating costs of the Department's power supply program after implementation of MRTU.

The MOU is an interim step. The IOUs and the Department intend, once they have sufficient certainty with respect to the MRTU-based structure of the DWR contracts, to use the MOU to develop specific changes to the operating and servicing order/agreements. Those changes will be presented to the Commission for approval.

The implementation of MRTU does not affect the Bond Charge.

## ADMINISTRATIVE AND GENERAL COSTS

The Department's administrative and general costs of $26.3 million consist of $22.3 million for appropriated budget expenditures including funds for labor and benefits, pro rata charges for services provided to the power supply program by other State agencies and $4 million for consulting services for development and monitoring of the revenue requirements, litigation and dispute resolution support, power contract management, and financial advisory services for managing the $10 billion debt portfolio and related reserves.

## FINANCING RELATED ASSUMPTIONS

For purposes of calculating the interest earnings on account balances during 2010, the Department assumes a 2.44 percent earnings rate for the Debt Service Reserve Account and a 1.25 percent earnings rate for all other accounts during the 2010 Revenue Requirement Period.

The Department currently has $4.265 billion of fixed rate bonds outstanding, $3.812 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 2010 Revenue Requirement Period is 5.187 percent. The projected average interest rate for all hedged variable rate bonds (taking into account the hedges) is 3.954 percent.

For purposes of calculating the interest accruing on unhedged variable rate bonds during 2010, 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 2010 Revenue Requirement Period, on the basis of these assumptions, the interest rate on all unhedged variable rate bonds is projected to be 5.979 percent.

The Department projects that the amount of Bond Charge Revenues required for the 2010 Revenue Requirement Period will be $937 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 2010 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 2010 Determination, the Department has determined the MOEAB to be $195 million. The Department projects to exceed the MOEAB at all times during 2010. 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").

Based on the Stress Cases described below under "Sensitivity Analysis", the ORAR for the 2010 Revenue Requirement Period is determined by the Department to be $529 million.

## 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 2010 Revenue Requirement Period, the Department will calculate projected interest on unhedged Variable Rate Bonds at 5.979 percent.

For the 2010 Revenue Requirement Period, the Department has determined the Debt Service Reserve Requirement to be $980 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** |
|---|---|---|---|
| | **2010** | **2010** | **2010** |
| Q1 | 9.67 | 9.31 | 10.02 |
| Q2 | 9.37 | 8.87 | 9.78 |
| Q3 | 9.91 | 9.51 | 10.35 |
| Q4 | 10.91 | 10.56 | 11.61 |
| **Annual Average** | 9.97 | 9.56 | 10.44 |

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 2000 through April 2009 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, 2009. 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 2010 and 2011.

Lower loads are estimated in this case by assuming cooler-than-normal summers during 2010 and 2011, 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 2010 and 2011 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 2010 and two percent in 2011. 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 2010 and 2011. URG is further decreased by assuming an unplanned outage at one northern California nuclear power plant unit from January 2010 through

March 2010 and at one southern California nuclear power plant unit from April 2010 through March 2011. 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 2010 and 1.4 percent higher in 2011. 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 2010 and 2011. 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 2010 and 2011 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 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.

## 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 2010 Revenue Requirement Period after this 2010 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; 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 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 |

## THE 2010 DETERMINATION

## PUBLIC 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.

On June 18, 2009, the Department issued its Proposed Determination of Revenue Requirements for the period January 1, 2010, through December 31, 2010 for public review and comment under the Regulations promulgated pursuant to the California Administrative Procedures Act. 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.

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

JUST AND REASONABLE DETERMINATION

After assessing the administrative record, the Act, the Regulations, Bond Indenture requirements and the Rate Agreement, the Department finds this 2010 Revenue Requirement Determination for the period of January 1, 2010 through December 31, 2010, to be just and reasonable.

## 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 2010 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 IV as a market simulation tool;
- Analysis of retirement and additions of WECC generation resources; and
- California ISO Locational Marginal Price and Congestion Revenue Rights proposals.

More detailed information about the market simulation utilized by the Department, including descriptions of the inputs and assumptions is referenced in Section J of the 2008 Revenue Requirement[8].

## I. COMMENTS RECEIVED ON THE PROPOSED 2010 DETERMINATION AND THE DEPARTMENT'S RESPONSES

On June 18, 2009, the Department issued its Proposed 2010 Revenue Requirement Determination for the period January 1, 2010 through December 31, 2010. This document was made available for public review and comment. 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.

The Department received comments from San Diego Gas & Electric (SDG&E), Southern California Edison (SCE) and the Alliance for Retail Energy Markets (AReM). No other persons submitted comments. The Department reviewed and considered each comment and took action as appropriate. The comments and the Department's responses are reviewed below.

## SUMMARY OF CONTENTS OF SAN DIEGO GAS AND ELECTRIC

**SDG&E Comment #1:**
In their comments of July 9, 2009, SDG&E states that DWR should utilize the transmission-level load forecast provided to DWR's consultants [during the Data Request phase] without change. SDG&E notes that it appears that DWR adjusted the load forecast provided by SDG&E upward by 6.3% to account for transmission and distribution (T&D) losses, but that such an adjustment was unnecessary and T&D losses were already accounted for in the forecast provided by SDG&E.

**Response:** During the Data Request phase, the Department attempted to clarify the inclusion, exclusion, and magnitude of losses in load forecasts provided by each of the IOUs. In the case of SDG&E, the Department did not interpret the clarifications correctly and did adjust the load forecast provided by SDG&E upward by SDG&E's stated T&D loss levels of 6.3%. The Department has revised SDG&E's load forecast in this Determination. The revision of loads provided by SDG&E does not have an impact on the dispatch of regional resources, but it does have an impact on the projected level of customer sales and wholesale sales from the DWR contracts allocated to SDG&E.

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

## SUMMARY OF COMMENTS OF SOUTHERN CALIFORNIA EDISON

**SCE Comment #1:**
In their comments of July 9, 2009, SCE comments that it would be appropriate to address the issues related to the early release of operating reserves as part of R.09-06-018 (the CPUC Rulemaking to address the allocation of the 2010 Revenue Requirement Determination).

**Response:** The Department recognizes the CPUC's authority in allocating the Revenue Requirement among the customers of the IOUs and will continue to support the CPUC and the IOUs in the process of allocating the Revenue Requirement, as appropriate.

An important factor in determining when and how reserves are released is the timing of any novation of DWR contracts.

To determine if amounts in the operating account are available for release, DWR will use the same set of projections and stress tests as is required for an annual revenue requirement determination. If the amount deemed available for release is small, it might make sense from a financial and rate perspective to wait until the next annual revenue requirement proceeding to adjust the operating balances and revenue requirements.

If DWR determines that a revision of its revenue requirement is warranted, it would prepare a revision based on the remaining power contract portfolio and the operating reserves will, as always, be based on provisions in the Bond Indenture. It would submit the revision to the CPUC so that the CPUC could allocate the reduction to ratepayers. The CPUC, after consultation with DWR, decides how any amount determined to be excess shall be used. The uses available to the CPUC are to (1) reduce power charges, (2) reduce bond charges or (3) with the agreement of DWR, pay or provide for the defeasance of Bonds.

The decision process will, as always, consider the interests of the retail customers of the IOUs and of DWR, and, if applicable, direct access customers. If a use is proposed for excess amounts other than those noted above, that use must be consistent with the authorization under AB1X.

**SCE Comment #2:**
SCE comments that the Proposed Determination projects an average 2010 natural gas price of $5.79/MMBtu at the Southern California Border, and that this differs somewhat from a more recent "publicly-available" forecast of $5.42/MMBtu at the Southern California Border. SCE comments that DWR should continue to monitor these prices and update its forecast, if needed, before final implementation of the 2010 Revenue Requirement Determination.

**Response:** The Department recognizes that natural gas price projections underlying the Proposed Determination differ from recent price projections and notes that this will almost always be the case, due to the nature of examining forward markets at different points in time. As is its practice, the Department will be updating its natural gas price forecast for 2010 and 2011 by October 2009.

## SUMMARY OF COMMENTS OF THE ALLIANCE FOR RETAIL ENERGY MARKETS

**AReM Comment #1:**
In their comments of July 10, 2009, AReM requests that DWR propose in its Final Revenue Requirement Determination that all operating reserve reductions associated with the expiration of power contracts be explicitly refunded to customers who paid the Bond Charge.

**Response:** The disposition of any deemed surplus in operating reserves will be managed as part of the Department's Revenue Requirement process. The Department recognizes the CPUC's authority in allocating the Revenue Requirement among the customers of the IOUs and will continue to support the CPUC and the IOUs in the process of allocating the Revenue Requirement, as appropriate.

A portion of the operating reserves were funded by bond proceeds. The 2002 Power Supply Revenue Bond Sources and Uses reports that $624,900,305 of bond proceeds were deposited in the Operating Account. At the time, DWR targeted to maintain the Operating Account at $1 billion. The 2003 Supplemental Revenue Requirement reduced the Operating Account balances by approximately $1 billion through a bill credit for ratepayers in the IOU service areas. All other operating reserves were funded through power charges

As noted in the Department's consideration of comments made by SCE, the CPUC after consultation with DWR decides how any amount determined to be excess shall be used. The uses available to the CPUC are to (1) reduce power charges, (2) reduce bond charges or (3) with the agreement of DWR, pay or provide for the defeasance of Bonds.

The decision process will, as always, consider the interests of the retail customers of the IOUs and of DWR, and, if applicable, direct access customers. Any use of excess amounts other than those noted above, a determination must be made as to whether the proposed use is for a purpose authorized by AB1X.

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

| Volume | Record Number | Date | Record Title |
|---|---|---|---|
| DWR10pRR | 001 | 10/29/08 | Revised Revenue Requirement Determination for 2009, including the Revised Determination, The Notice, and the Transmittal letter from CERS to the Commission |
| DWR10pRR | 002 | 11/21/08 | Decision 08-11-056: "Decision Authorizing Measures To Facilitate Removal Of Department Of Water Resources From The Role Of Supplying Electric Power" |
| DWR10pRR | 003 | 12/04/08 | Decision 08-12-006: "Decision Allocating The revised 2009 Revenue Requirement Determination Of The California Department Of Water Resources" |
| DWR10pRR | 004 | 12/05/08 | ALJ ruling regarding the date of issuance of Decision 08-12-006 and shortening of time for responses to any application for rehearing. The effective date of the Decision is December 4, 2008. |
| DWR10pRR | 005 | 12/12/08 | SDG&E Advice Letter 2047-E: Revisions To The DWR Power Charge And DWR Bond Charge Pursuant To D.08.12.006 |
| DWR10pRR | 006 | 12/15/08 | PG&E Advice Letter 3379-E: 2009 Department of Water Resources Revenue Requirement Determination in compliance with D.08-12-006 |
| DWR10pRR | 007 | 12/15/08 | SCE Advice Letter 2296-E: Implementation of the 2009 California Department of Water Resources Power and Bond Charges in Accordance With Decision 08-12-006 |
| DWR10pRR | 008 | 12/24/08 | SCE Supplemental Advice Letter 2296-E-A: |
| DWR10pRR | 009 | 12/26/08 | SCE Substitute Sheets for Advice Letter 2296-E-A |
| DWR10pRR | 010 | 01/23/09 | PG&E Advice 3407-E: Electric Rate Changes for DWR, and other revisions |
| DWR10pRR | 011 | 01/29/09 | PG&E Advice 3407-E Substitute Sheet: Electric Rate Changes for DWR, and other revisions |
| DWR10pRR | 012 | 02/13/09 | Joint Motion Of PG&E, SDG&E and SCE Regarding Servicing And Operating Agreements |
| DWR10pRR | 013 | 02/19/09 | CDWR memo to the Commission in support of the joint motion of the IOUs regarding Servicing and Operating Orders and Agreements |
| DWR10pRR | 014 | 03/13/09 | Assigned Commissioner's Ruling On The February 13, 2009 Joint Motion |
| DWR10pRR | 015 | 03/31/09 | DWR "Russell Mills" email to PG&E advising of near term kickoff of 2010 Revenue Requirement Process and acknowledging the PG&E change of Case Manager |

| Volume | Record Number | Date | Record Title |
|---|---|---|---|
| DWR10pRR | 016 | 04/01/09 | DWR “Russell Mills” email to SCE advising of near term kickoff of 2010 Revenue Requirement Process |
| DWR10pRR | 017 | 04/01/09 | DWR “Russell Mills” email to SDG&E advising of near term kickoff of 2010 Revenue Requirement Process |
| DWR10pRR | 018 | 04/09/09 | DWR “Russell Mills” email transmittal of Data Request 1 to PG&E, SCE and SDG&E |
| DWR10pRR | 019 | 04/13/09 | DWR Response to SCE Question Re. Uncollectible Percentage |
| DWR10pRR | 020 | 04/22/09 | DWR Response to SCE Question Re. Contracts |
| DWR10pRR | 021 | 04/22/09 | DWR Additional Response to SCE Question Re. Contracts |
| DWR10pRR | 022 | 04/22/09 | DWR Additional Response to SCE Questions Re. Contracts |
| DWR10pRR | 023 | 04/24/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE response to DWR Data Request 1 |
| DWR10pRR | 024 | 04/24/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E response to DWR Data Request 1 |
| DWR10pRR | 025 | 04/24/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE response to DWR Data Request 1, Q2 |
| DWR10pRR | 026 | 04/29/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E response to DWR Data Request 1 |
| DWR10pRR | 027 | 05/01/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Supplemental response to DWR Data Request 1Q1.b |
| DWR10pRR | 028 | 05/04/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Supplemental response to DWR Data Request 1Q8 |
| DWR10pRR | 029 | 05/05/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E response to DWR Data Request 1Contract Question |
| DWR10pRR | 030 | 05/07/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E response to DWR Data Request Question |
| DWR10pRR | 031 | 05/07/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE response to DWR Data Request Question |
| DWR10pRR | 032 | 05/07/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E response to DWR Data Request Question |
| DWR10pRR | 033 | 05/11/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: Additional DWR Data Request Questions to SDG&E |
| DWR10pRR | 034 | 05/20/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E response to DWR Data Request Questions |
| DWR10pRR | 035 | 05/26/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Preliminary Dispatch and contract Estimates - SCE |
| DWR10pRR | 036 | 05/26/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Preliminary Dispatch and contract Estimates – SDG&E |
| DWR10pRR | 037 | 05/26/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Preliminary Dispatch and contract Estimates – PG&E |
| DWR10pRR | 038 | 05/27/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR – PG&E email series re. Preliminary Dispatch, Contract Estimates and Fuel costs |

| Volume | Record Number | Date | Record Title |
|---|---|---|---|
| DWR10pRR | 039 | 05/27/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE supplemental response to DWR Data Request |
| DWR10pRR | 040 | 05/29/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR – PG&E email series re. Preliminary Dispatch, Contract |
| DWR10pRR | 041 | 05/29/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR – SDG&E emails regarding the SDG&E response to the |
| DWR10pRR | 042 | 06/10/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR – SCE emails regarding Contract Data |
| DWR10pRR | 043 | 06/11/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Spring 2009 Base Case Gas Price Forecast |
| DWR10pRR | 044 | 06/11/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Spring Stress Case Gas Price Forecast |
| DWR10pRR | 045 | 06/11/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR workpaper describing IOU transfer payment methodology |
| DWR10RR | 046 | 06/18/09 | The Proposed Determination of Revenue Requirements including email transmittal, The Notification and The Proposed Determination. |
| DWR10RR | 047 | 06/18/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Transmittal of Documentation Supporting the Proposed 2010 Revenue Requirement Determination Specific to SDG&E |
| DWR10RR | 048 | 06/18/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Transmittal of Documentation Supporting the Proposed 2010 Revenue Requirement Determination Specific to PG&E |
| DWR10RR | 049 | 06/18/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Transmittal of Documentation Supporting the Proposed 2010 Revenue Requirement Determination Specific to SCE |
| DWR10RR | 050 | 06/23/09 | Commission Notice of Assignment Rulemaking 09-06-018 |
| DWR10RR | 051 | 06/23/09 | Commission Order Instituting Rulemaking 09-06-018 |
| DWR10RR | 052 | 06/18/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Questions regarding Supporting Material |
| DWR10RR | 053 | 06/24/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR – PG&E email series regarding Questions on Supporting Material |
| DWR10RR | 054 | 06/23/09 | CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E email regarding Questions on Supporting Material |
| DWR10RR | 055 | 07/09/09 | PG&E Comments on the Proposed Determination – No Comments |
| DWR10RR | 056 | 07/09/09 | SDG&E Comments on the Proposed Determination |
| DWR10RR | 057 | 07/09/09 | SCE Comments on the Proposed Determination |