State of California

Department of Water Resources

Supplemental Determination of Revenue Requirements

For the Period

January 1, 2003 Through December 31, 2003

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

And in Response to
The Request of the California Public Utilities Commission
Decision 02-12-045

July 1, 2003

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A. The Supplemental Determination

In this Supplemental Determination of Revenue Requirements for the period January 1, 2003 through December 31, 2003, (this "Supplemental Determination"), the California Department of Water Resources ("the Department" or "DWR") is reducing its 2003 revenue requirements as described herein. The Department has identified that, assuming current customer rates remain in place throughout 2003, it will have $1.002 billion more in revenues than are needed to meet its required reserve and operational requirements. The Department has considered the appropriateness of making a reduction to its revenue requirements including consideration of comments provided by the California investor owned utilities ("IOUs" or "Utilities") on June 23, 2003, relative to the Proposed Determination published June 2, 2003, pursuant to regulations promulgated under the California Administrative Procedure Act ("APA"), before reaching this Supplemental Determination. Having affirmed the appropriateness of reducing the 2003 revenue requirements, the Department hereby submits this Supplemental Determination to the California Public Utilities Commission ("CPUC" or "Commission") for purposes of allocating the reduction among electric retail customers in the service territories of the IOUs.

GENERAL

On August 16, 2002, the Department published its Determination of Revenue Requirements for the period of January 1, 2003 through December 31, 2003 (the "August 16, 2002 Determination"). The August 16, 2002 Determination was submitted to the Commission on August 19, 2002. On December 17, 2002, the Commission rendered Decision 02-12-045 "Opinion Adopting Interim Allocation Of the 2003 Revenue Requirement of The California Department of Water Resources." Decision 02-12-052 (Order Correcting Error) was also issued on December 17, 2002, correcting various tables and numbers contained in Decision 02-12-045. Decision 02-12-045 excluded $29 million identified in relation to a power contract agreement between the Department and the California Consumer Power and Conservation Financing Authority ("the California Power Authority" or "CPA"). On February 13, 2003, the Commission issued Decision 03-02-031 amending Decision 02-12-045, as corrected by Decision 02-12-052, to allocate the aforementioned $29 million. Within this Supplemental Determination, reference to Decision 02-12-045 will encompass the modifications contained in Decision 02-12-052 and Decision 03-02-031.

Decision 02-12-045 allocated among customers of the three IOUs – namely Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE") and San Diego Gas and Electric ("SDG&E"), the cost of the Department's 2003 revenue requirement for its power purchase program. Within Decision 02-12-045, the Commission requested that the Department submit a supplemental determination "to update its modeling efforts to incorporate direct access migration, to provide all parties an equal opportunity to contribute to the modeling assumptions and inputs, to treat sales of excess energy consistently with the protocols adopted in Decision 02-09-053[1], and to refine assumptions regarding ancillary services and cash reserve levels."

Decision 02-12-045 also confirmed that "[i]ssues relating to the true-up of DWR's 2001-2002 revenue requirement will be addressed after actual data for 2002 becomes available . . . ."

The Department has reviewed the matters raised in Decision 02-12-045 and other matters relating to the Department's 2003 revenue requirement, including, but not limited to, renegotiated contracts; Commission decisions issued subsequent to the August 16, 2002 Determination; PG&E input received after the submission of the August 16, 2002 Determination to the Commission; new assumptions provided by parties in response to Ordering Paragraph 5 in Commission Decision 02-12-045; transition of the responsibility for the residual net short to the IOUs; developments in natural gas markets; the preliminary results of operations of the Electric Power Fund (the "Fund") through the end of March 2003; and developments with respect to the treatment of power delivered to the Western Area Power Administration ("WAPA"). The Department has concluded that a supplemental revenue requirement determination addressing the following issues would be useful to the Commission in adjusting the allocation of revenue requirements established by Decision 02-12-045, and would provide benefit to the retail rate payers of the IOUs.

- Sales of excess energy (Decision 02-09-053);
- Ancillary services/ISO expenses;
- Contract renegotiations;
- Fuel costs;
- WAPA energy supplies and associated remittance treatment;
- Direct Access Cost Responsibility Surcharge;
- Cash reserve levels (Operating Account and Operating Reserve Account);
- Hydroelectric conditions in California and the Pacific Northwest;
- Other proposed changes received from parties on December 30, 2002;
- Sensitivity analysis; and
- Results of bond sales.

Capitalized terms not defined herein have the meanings given to such terms in the August 16, 2002 Determination.

[1] On September 19, 2002, the Commission adopted Decision 02-09-053, which ordered PG&E, SDG&E, and SCE, to assume all of the operational, dispatch, and administrative functions for the DWR Contracts. The decision also allocated the DWR Contracts to the resource portfolios of the three utilities to be scheduled and dispatched in a least-cost manner, and addressed other issues.

RELATIONSHIP TO OTHER DETERMINATIONS OF THE DEPARTMENT'S REVENUE REQUIREMENTS

This Supplemental Determination addresses only those changes under the subjects noted above. The results of bond sales are included in Section H. The actual costs for the Department's expenses incurred and revenue received associated with the 2001 and 2002 revenue requirements will be the subject of a "true-up" to be accounted for in a separate determination and submission to the Commission. This will be completed when all costs and revenue data are available, including those attributable to the California Independent System Operator ("CAISO" or "ISO") for which there is a significant lag as a result of the ISO's settlements process. In addition, there will be a determination of the Department's 2004 revenue requirement to be prepared and submitted later this year with the Commission.

HIGHLIGHTS OF THE SUPPLEMENTAL DETERMINATION OF REVENUE REQUIREMENTS

The Department hereby determines, on the basis of the materials presented and referred to by this Supplemental Determination, its Retail Revenue Requirement[2] for the period of January 1, 2003 through December 31, 2003, to be $3.288 billion taking into account the application of the Operating Account surplus described below.

The transition of responsibility for the procurement of the residual net short from the Department to the IOUs and a reexamination of possible future outcomes under stress scenarios permit the Department to reduce Minimum Operating Expense Available Balance (MOEAB) from $1 billion to $348 million, and to reduce Operating Reserve Account Requirement (ORAR) from $777 million to $630 million. The current ORAR of $777 million was based on 18 percent of total 2003 operating expenses as required by the Trust Indenture authorizing and securing Power Supply Revenue Bonds ("the Bond Indenture"). The $630 million target balance is calculated based on the maximum seven-month difference in operating expenses and revenues. In addition, the reexamination of the Stress Case isolated the cash flow outcome resulting solely from the Stress Case as compared to the Base Case outcome. The total reduction in fund balance requirements is $799 million from the fund balance requirements identified in the August 16, 2002 Determination. In addition, on January 1, 2003, the Department began the 2003 Revenue Requirement Period with $44 million more than was projected in the August 16, 2002 Determination.

The Department's revenues from Retail End Use Customers projected in the August 2002 filing have decreased by $1.360 billion due to the load and contract dispatch changes described in Section E.

Finally, the Department expects to receive from PG&E the applicable DWR charges for energy in the amount equal to the energy delivered by PG&E to WAPA ("WAPA volumes"). The amount of such charges relating to the period January 17, 2001 through the end of March 2003, is estimated to be at least $539 million. It is imperative to note that there is no certainty relative to the date on which PG&E will remit these funds to the

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2 Although the Department will use herein the term "Retail Revenue Requirement" which, as defined by the Rate Agreement, means the amounts to be generated from Power Charges on Retail End Use Customers (i.e., bundled customers of the IOUs), such revenue requirement may also be satisfied by Direct Access Power Charge Revenues (as that term is defined in the Bond Indenture).

Department. Because it is the Department's view that such amounts are now due and owing and because it is conservative from an operating reserve requirements perspective to assume earlier receipt and use of these amounts to reduce the Department's revenue requirement (rather than receipt in the last quarter of 2003, for example), for purposes of this Supplemental Determination, July 1, 2003, is assumed to be the date by which the Department receives said moneys. Any revenue requirements effects resulting from PG&E's delay, beyond this date, in remitting the moneys will be taken into account in proceedings subsequent to this 2003 Supplemental Determination. After, and only after, the Department receives this remittance from PG&E, the funds are projected to be available for payment of Department Costs, in lieu of Power Charge Revenues from current power sales. Further details about remittance relating to WAPA volumes are noted in Section E.

Taking into account the factors summarized in the three preceding paragraphs, and conditioned upon the receipt from PG&E of at least the $539 million described above, the amount in the Operating Account on July 1, 2003, in excess of the amount then required (if DWR charges were not modified) is projected to be $1.002 billion. As a result the Department hereby determines that its Retail Revenue Requirement for the period July 1, 2003 through and including December 31, 2003, net of the application of the $1.002 billion projected reduction in reserves and operating requirement, is $2.041 billion on a cash basis. Such requirement may be implemented in a manner that assumes that $1.002 billion is available to pay Department Costs immediately as of July 1, 2003 (i.e., need not be reserved).

SUMMARY OF THE PROPOSED
RETAIL REVENUE REQUIREMENT REDUCTION

Description	Total
	$ millions
Sources of Funds for Reduction	
Change in Beginning Operating Account	44
Minimum Operating Expense Available Balance Reduction in Operating Account	652
Reduction in Operating Reserve Account Requirement	147
PG&E Remittance of "WAPA" Amounts	539
Total Sources for Reduction	1,382
Uses of Funds for Reduction	
Energy Changes affecting Revenues	380
Reduction Available after July 1, 2003	1,002
Total Uses of Funds	1,382

Table A-1 shows a summary of the Department's revenue requirements and the accounts associated with its projected Department Costs ("Power Charge Accounts") for the Revenue Requirement Period. These figures are compared to those reflected in the August 16, 2002 Determination. Assumptions related to the current requirements are included in Section E.

TABLE A-1
SUMMARY OF THE DEPARTMENT'S 2003 POWER CHARGE REVENUE REQUIREMENT AND POWER CHARGE ACCOUNTS [1]

Line	Description	2003 Supplemental Filing	August 2002 Determination	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	1,272	1,228	44
3	Priority Contract Amount	-	-	-
4	Operating Reserve Account	777	777	0
5	**Total Beginning Balance in Power Charge Accounts**	**2,050**	**2,005**	**45**
6	*Power Charge Accounts Operating Revenues*			
7	Power Charge Revenues from Bundled Customers	3,288	4,648	(1,360)
8	Power Charge Revenues from Direct Access Customers	14	-	14
9	Extraordinary Receipts from Utilities	539	-	539
10	Other Power Sales	132	129	3
11	Interest Earnings on Fund Balances	32	59	(27)
12	**Total Power Charge Accounts Operating Revenues**	**4,005**	**4,836**	**(831)**
13	*Power Charge Accounts Operating Expenses*			
14	Administrative and General Expenses	49	28	21
15	Total Power Costs	4,628	4,120	508
16	Ancillary Services	22	170	(148)
17	**Total Power Charge Accounts Operating Expenses**	**4,698**	**4,318**	**380**
18	Net Operating Revenues	(693)	518	(1,211)
19	Net Transfers from/(to) Bond Charge Accounts	-	-	-
20	Total Net Revenues	(693)	518	(1,211)
21	**Ending Aggregate Balance in Power Charge Accounts**	**1,357**	**2,523**	**(1,166)**

2003 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.	348	1,000	(652)
Operating Reserve Account: Used to cover deficiencies in the Operating Account. It is sized as the maximum seven-month difference between operating revenues and expenses as calculated under "stress" operating conditions.	630	777	(147)
Total Operating Reserves:	978	1,777	(799)

[1]Numbers may not add due to rounding

B. Background

The August 16, 2002 Determination provided background information related to Section 80110 of the Water Code and a history of the Department's various submittals. The background information included a review of the adoption of a Rate Agreement between the Commission and the Department and discussed the purpose and actions required under the Rate Agreement.

For purposes of this Supplemental Determination, the background information contained in the August 16, 2002 Determination is incorporated by reference and will not be repeated herein. The August 16, 2002 Determination and the administrative record of materials on which it was based are part of the administrative record of materials underlying this Supplemental Determination.

On June 14, 2002, the Department published its Proposed Determination of Revenue Requirements for the period of January 1, 2003 through December 31, 2003 ("Proposed Determination"). In compliance with emergency regulations promulgated under the APA and California Water Code Section 80014(a), opportunity was provided for public comment on the Proposed Determination. Comments were received, reviewed, and where appropriate, incorporated into the Department's Final Determination issued on August 16, 2002[3]. This August 16, 2002 Determination was forwarded to the Commission on August 19, 2002, thereby starting the 120-day period for Commission action to allocate the Department's revenue requirement, as provided in the Rate Agreement.

The August 16, 2002 Determination was based on information obtained by the Department from the three IOUs and other sources, existing legislation, Commission Decisions and the Department's emergency regulations. To perform the computer simulations of electric energy market production and dispatch used in determining the revenue requirements, PROSYM, a price forecasting and market simulation tool, was used[4].

Subsequent to the issuance of the August 16, 2002 Determination, there have been significant developments that impact the Department's revenue requirements for 2003. First, PG&E provided new information that has bearing on the Determination. PG&E's comments addressed ancillary services, Direct Access migration, the reduction of reserve requirements, certain changes to modeling assumptions, Diablo Canyon capacity and availability, bilateral contract capacity and energy, the need to model the Etiwanda Power Plant as a part of PG&E's URG, the incorrect modeling of the Potrero Power Plant as a part of PG&E's URG, self-generation load assumptions, WAPA modeling and the incorrect modeling of the San Juan 3 Power Plant as a part of SCE's URG. The Department's analysis of the information was provided to the Commission during the August 16, 2002 Determination hearing held on October 3 and 4, 2002. PG&E discussed the new information in the Testimony of William Tom in that proceeding. Second, the Commission took several actions, including the adoption of decisions addressing the allocation of the Department's long-term contracts and variable costs, operating arrangements governing the IOUs' operation, administration and dispatch of the Department's long-term contracts, establishing certain exemptions from the Department's Bond Charge, and implementing the suspension of Direct Access. Third, the sale of power bonds by the Department in October and November 2002 resulted in an adjustment to certain bond related data provided in the August 16, 2002 Determination.

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3 For further information pertaining to the process followed, refer to the August 16, 2002 Determination, Section G entitled "Just and Reasonable Determination".

4 Included in the August 16, 2002 Determination is Appendix 1, "Market Simulation". Refer to this appendix for further information on the simulation process and on PROSYM.

At the request of the Commission, SDG&E and PG&E, a new simulation model run was generated incorporating several changes. The results of the new run were provided to the Commission for the purpose of aiding the Commission in its allocation proceeding.

On December 17, 2002, the Commission issued Decision 02-12-045 "Opinion Adopting Interim Allocation Of The 2003 Revenue Requirement Of The California Department Of Water Resources." Decision 02-12-052 "Order Correcting Error" was also issued on December 17, 2002, correcting various tables and numbers contained in Decision 02-12-045. In Decision 02-12-045, the Commission excluded $29 million associated with a Demand Reserves Purchase Agreement between the Department and the CPA. After receiving comments from the Department, the Commission reopened the matter on its own motion. On February 13, 2003, the Commission adopted Decision 03-02-031 expressly allocating the $29 million as part of the Department's revenue requirement. A chronology of the relevant Commission proceedings from publication of the August 16, 2002 Determination through issuance of the Proposed Decision on November 15, 2002, is contained in the Summary section of the initial Decision 02-12-045, a copy of which is included in the administrative record supporting this Supplemental Determination.

The Commission determined that information contained in the updated PROSYM run submitted to the Commission for purposes of considering the allocation of the Department's revenue requirement had not been provided to interested parties in time to allow for sufficient review and, therefore, would not be utilized in the allocation decision. Instead, the Commission requested that the Department submit a Supplemental Determination incorporating new or revised data and updated assumptions. To facilitate the requested supplemental filing, the Commission ordered: "No later than December 30, 2002, parties may submit information and assumptions for DWR's use in a supplemental determination."[5]

In compliance with Decision 02-12-045, PG&E, SCE, SDG&E and the California Large Energy Consumers Association ("CLECA") submitted assumptions for the Department's consideration in a supplemental determination.

The Department has analyzed potential changes to the 2003 Revenue Requirement Determination and herein concludes it is appropriate and beneficial to update the August 16, 2002 Determination with a Supplemental Determination addressing and incorporating significant changes that arose subsequent to the August 16, 2002 Determination.

Factors relative to this Supplemental Determination, including the issues identified by the Commission, assumptions and updated information submitted by the three IOUs and CLECA, and other significant changes recognized by the Department, are identified and discussed in Section E of this Supplemental Determination.

[5] Decision 02-12-045, ordering paragraph number 5 on page 61.

C. Reconciliation

This section provides a reconciliation of the significant changes with respect to the Retail Revenue Requirement and projected Department Costs, Power Charge Revenues and Direct Access Power Charge Revenues.

POWER CHARGE ACCOUNTS OPERATING EXPENSES
Total Department Costs (specified below) are projected to increase by $380 million.

TABLE C-1
SUMMARY OF THE DEPARTMENT'S REVENUE REQUIREMENTS USING CURRENT DWR RATE FOR POWER

Line	Description	Supplemental Filing	August Determination	Supplemental minus August
				Inc/(Reduction)
		$ Millions	$ Millions	$ Millions
1	*Power Charge Accounts Operating Expenses*			
2	Administrative and General Expenses	49	28	21
3	Total Power Costs	4,628	4,120	508
4	Ancillary Services	22	170	(148)
5	**Total Power Charge Accounts Operating Expenses**	**4,698**	**4,318**	**380**

ADMINISTRATIVE AND GENERAL COSTS
Administrative and general costs are expected to increase by $21 million over the original estimate for 2003. This increase is attributable primarily to additional costs for the renegotiation of long-term contracts ($11 million), increased litigation support costs ($7 million), and necessary costs to effect the transition of the residual net short to the IOUs ($3 million). These increases were included in an augmentation to the Department's administrative budget that was approved by the Joint Legislative Budget Committee in the spring of 2003.

Actual 2002 Administrative and General costs were $70.4 million. When compared to actual 2002 costs, the 2003 costs decrease by $21 million.

The original budget of $28 million in the August 16, 2002 Determination was based on the approved budget by the Legislature for the fiscal year ending June 30, 2003, and did contemplate a reduction in certain operational costs over the prior year budget because of the expected transition of residual net short responsibilities to the IOUs as of January 1, 2003. However, the original budget did not contemplate the extensive and difficult renegotiation of long-term contracts which continues and has resulted in savings of $6 billion to date in contract costs. Also, additional litigation costs have been incurred for a variety of issues including FERC proceedings regarding the just and reasonableness of the long-term contracts. Transition costs include costs to implement operating arrangements and other protocols with the IOUs to insure that the IOUs properly manage the Department's long-term contracts, while recognizing the Department's financial and legal responsibilities with respect to its operating expenditures, which exceed $4 billion per year.

TOTAL POWER COSTS

The August 16, 2002 Determination projected the sale of 44,063,907 MWh, which has been revised to 42,002,096 MWh, a decrease of 2,061,811 MWh. The key factors contributing to the reduction in projected power sales were described in the Department's testimony provided during the Commission's process to allocate the August 16, 2002 Determination, a copy of which is included in the administrative record supporting this Supplemental Determination. Other changes in load and resource assumptions are described in Section E.

In spite of the decrease in power sales, the total cost of purchased power is expected to increase by $508 million. This increase is attributed primarily to the factors discussed in Section E, including significantly increased fuel expenses and certain power contract renegotiations.

ANCILLARY SERVICE COSTS

Ancillary service costs are projected to decrease by $148 million. At the time of the August 16, 2002 Determination, the Department concluded it might need to continue to pay these costs in 2003. This has not been the case. Instead, ancillary service costs became the responsibility of the three IOUs effective January 1, 2003. Consequently, as described in Section E, the Department has determined it is responsible for the costs that accrued in 2002 and capacity payments related to the Demand Reserves Purchase Agreement between the Department and the CPA.

POWER CHARGE ACCOUNTS OPERATING REVENUES

Total revenue for deposit in Power Charge Accounts (specified below) is projected to decrease by $831 million.

TABLE C-2
SUMMARY OF THE DEPARTMENT'S REVENUE CHANGE USING CURRENT DWR RATE FOR POWER

Line	Description	Supp. Revenue Expected	August Determination	Supp. minus August
				n)
		$ Millions	$ Millions	$ Millions
1	*Power Charge Accounts Operating Revenues*			
2	Power Charge Revenues from Bundled Customers	3,288	4,648	(1,360)
3	Power Charge Revenues from Direct Access Customers	14	-	14
4	Extraordinary Receipts from Utilities	539	-	539
5	Other Power Sales	132	129	3
6	Interest Earnings on Fund Balances	32	59	(27)
7	**Total Power Charge Accounts Operating Revenues**	**4,005**	**4,836**	**(831)**

POWER CHARGE REVENUES FROM BUNDLED CUSTOMERS

Power Charge Revenues from Retail End Use Customers (sometimes referred to as bundled customers) are projected to decrease by $1.360 billion (not taking into account the expected $539 million WAPA payment and assuming no change in Department charges and no adjustment for Direct Access Power Charge Revenues). As noted earlier, this is due to a decrease in the volume of expected power sales from the Department to retail customers and the revenue requirement reduction.

POWER CHARGE REVENUES FROM DIRECT ACCESS CUSTOMERS

Revenue from Direct Access customers is increased by $14 million, an amount representing the actual receipts through March 2003 of Direct Access Cost Responsibility Surcharge ("DA-CRS" or "CRS") payments from customers in the SCE and SDG&E service areas as described further in Section E. PG&E did not submit CRS revenue to the Department through March 2003. No such revenues were specifically projected in the August 16, 2002 Determination. Although SDG&E has remitted CRS revenues to the Department, it did not reduce the bundled Power Charge to offset these revenues. SDG&E is now requesting that the Commission direct the Department to return the CRS revenues so that SDG&E can offset memoranda accounts tracking bundled ratepayers costs.

OTHER POWER SALES

Revenue from Other Power Sales is projected to increase by $3 million. As described in Section E, included as part of Other Power Sales is an amount of $31 million for reimbursement by the IOUs for ISO related costs accrued and paid by the Department on behalf of the IOUs during 2002.

INTEREST EARNINGS ON FUND BALANCES

Revenue from Interest Earnings is projected to decrease by $27 million. This is a result of decreased account balances as described below.

POWER CHARGE ACCOUNT BALANCES

The MOEAB decreases by $652 million. With the Department no longer responsible for the procurement of the residual net short, the minimum required balance in the Operating Account may be substantially reduced by the Department consistent with the Bond Indenture. The Bond Indenture requires this amount to be "the maximum amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any one calendar month during that Revenue Requirement Period . . . 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."

The ORAR decreases by $147 million. This account is used to cover deficiencies in the Operating Account and is now required to be "the greater of (i) the largest aggregate amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any consecutive seven (7) calendar months commencing in [the] Revenue Requirement Period, and (ii) 12% of the Department's projected annual Operating Expenses for [the] Revenue Requirement Period [but] not less than [12%] of the Department's Operating Expenses for the most recent twelve (12) calendar month period.

D. The Department's Supplemental Determination of Revenue Requirements for The Period of January 1, 2003 Through December 31, 2003

SUPPLEMENTAL REVENUE REQUIREMENT DETERMINATION

For the 2003 Revenue Requirement Period, which commenced January 1, 2003 and ends December 31, 2003, the Department's revenue requirements consist of Department Costs (essentially the same as Operating Expenses) and Bond Related Costs. Department Costs are addressed below and Bond Related Costs are addressed in Section H.

Department Costs include:

(1) Costs associated with power supply to be delivered under the Department's existing Priority Long-Term Power Contracts ("PLTPCs");

(2) Operating reserves as determined by the Department (see Table A-1);

(3) Administrative and general expenses;

(4) Costs associated with ancillary services or ISO charges resulting from transactions which occurred in 2002, but were payable on a cash basis in 2003; and

(5) Costs associated with the provision of the residual net short accrued in December 2002 but paid in January 2003.

Revenues available to pay Department Costs include:

(1) Revenues from power sales other than to Retail End Use Customers;

(2) Interest earnings;

(3) Power Charge Revenues from Retail End Use Customers; and

(4) Direct Access Power Charge Revenues in the form of the CRS collected from Direct Access customers.

This Supplemental Determination is made on the premise that the Department will not procure the residual net short at any time during 2003 or 2004.

For 2003, the Department projects that it will incur the following costs: (a) $4.628 billion in costs for long-term power contract purchases to cover the net short requirement of the Customers associated with long-term energy supply contracts entered into by the Department prior to January 1, 2003 on behalf of its Retail End Use Customers; (b) $22 million to pay for ancillary services and ISO charges associated with transactions which took place in 2002, but were payable in 2003; (c) $49 million in administrative and general expenses; and (d) no net transfers to Bond Charge accounts. This results in a total of $4.698 billion in Department Costs.

Funds to meet these costs are provided from (a) $132 million from the Department's share of power sales not made to Retail End Use Customers; (b) $32 million of interest earned on Power Charge Account balances; and (c) $3.841 billion of Power Charge Revenues (including anticipated PG&E remittances of Power Charge Revenues related to WAPA volumes) and Direct Access Power Charge Revenues. These revenues total $4.005 billion. The remaining requirement of $706 million is met through a $706 million reduction in Power Charge Account balances.

Table D-1 provides a quarterly review of costs and revenues associated with the Power Purchase Program.

TABLE D-1
POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE:
RETAIL CUSTOMER POWER CHARGE CASH REQUIREMENT

Line	Description	Amounts for Revenue Requirement Period (Millions of Dollars)				
		2003 - Q1	**2003 - Q2**	**2003 - Q3**	**2003 - Q4**	**Total**
1	*Power Charge Accounts Expenses*					-
2	Power Costs	1,081	763	1,516	1,268	4,628
3	Ancillary Services	-	7	7	7	22
4	Administrative and General Expenses	10	13	13	13	49
5	Debt Service	-	-	-	-	-
6	Net Transfers from/(to) Bond Charge Accounts	-	-	-	-	-
7	Net Changes to Power Charge Account Balances	(87)	80	(469)	(231)	(706)
8	**Total Power Charge Accounts Expenses**	**1,004**	**863**	**1,067**	**1,058**	**3,992**
9	*Power Charge Accounts Revenues*					
10	Other Power Sales Revenues	46	26	33	26	132
11	Interest Earnings on Power Charge Account Balances	8	-	24	-	32
12	Net Loan Proceeds	-	-	-	-	-
13	Retail Customer Power Charge Revenue Requirement[1]	949	837	1,009	1,031	3,827
14	**Total Power Charge Accounts Revenues**	**1,004**	**863**	**1,067**	**1,058**	**3,992**

[1]Includes extraordinary receipts. See Table A:1 line 9.

E. Assumptions Governing the Department's Supplemental Revenue Requirements for the 2003 Revenue Requirement Time Period

Revenue Requirements for the period January 1, 2003, through and including December 31, 2003, are based on assumptions regarding sales, power supply, natural gas prices, off-system sales, ancillary services/ISO charges, demand side management and conservation, and administrative and general expenses. Many assumptions are unchanged from the Department's August 16, 2002 Determination, and included in the Commission's Decision 02-12-045. Other assumptions have changed based upon information made available subsequent to August 16, 2002, and the revised assumptions identified and explained in detail below. In Decision 02-12-045, the Commission provided opportunity for parties to submit new or revised assumptions no later than December 30, 2002, for the Department to consider in a supplemental determination. PG&E, SCE, SDG&E and CLECA provided responses. These assumptions reflect consideration of various input received from the noted parties.

On February 13, 2003, a meeting was held at the CPUC, involving the Commission, the Department and the IOUs. During the meeting, the Department reviewed results of a preliminary assessment of the Department's revenue requirement using updated information and requested comments and additional information from the IOUs to continue the assessment. On February 24, 2003, the Department received additional input from the IOUs.

This Supplemental Determination addresses the following specific areas:

- Sales of Excess Energy (Decision 02-09-053);
- Ancillary Services/ISO Expenses;
- Contract Renegotiations;
- Fuel Costs;
- WAPA Treatment;
- Direct Access Cost Responsibility Surcharge;
- Cash Reserve Levels (Operating Account and Operating Reserve Account);
- Hydroelectric Conditions in California and the Pacific Northwest;
- Other Proposed Changes Received from Parties on December 30, 2002; and
- Sensitivity Analysis.

SALES OF EXCESS ENERGY (DECISION 02-09-053)
On September 19, 2002, the Commission issued Decision 02-09-053, Interim Opinion on Procurement Issues: DWR Contract Allocation. This Decision allocated each of the thirty-

five PLTPCs with twenty-four counterparties to the individual IOUs. The production simulation analysis has been updated to reflect the contract allocation.

Decision 02-09-053 also determined that proceeds from the sales of excess energy (off-system sales) would be shared between the specific IOU effecting the sale and the Department. This sharing reduces the anticipated revenues contained in the August 16, 2002 Determination and dramatically changes the amount of Department energy used to collect the revenue requirement.

As a result of Decision 02-09-053, the Department anticipates less revenue from the sale of excess energy than was estimated in the August 16, 2002 Determination. Specifically, the Department estimated revenues of approximately $129 million from the sale of excess energy in the August 16, 2002 Determination. In this Supplemental Determination, the Department estimates revenues of approximately $100 million from the sale of excess energy, a decrease in revenues of $29 million. Included as part of Other Power Sales, is an amount of $31 million for reimbursement of ISO-related costs accrued and paid by the Department in 2002, on behalf of the IOUs. This results in a net increase of $2 million.

ANCILLARY SERVICES/ISO EXPENSES

At the time of the August 16, 2002 Determination, the Department concluded it might need to continue to pay ancillary service costs in 2003. This has not been the case. Instead, ancillary service costs became the responsibility of the IOUs effective January 1, 2003. Consequently, the Department is only paying for costs that accrued in 2002 and capacity payments related to the Demand Reserves Purchase Agreement between the Department and the CPA. The Department estimates these costs at $22 million, and has included them in this Supplemental Determination. This is compared to an estimate of ISO-related costs of $170 million that was included in the August 16, 2002 Determination. The net effect is a decrease of $148 million of ISO-related costs.

CONTRACT RENEGOTIATIONS

Subsequent to the August 16, 2002 Determination, the following contracts have been renegotiated:

Alliance SRA A
Alliance SRA B
Capital Power-BioMass (terminated)
Clearwood-Geothermal
PGE Trading-Wind
Santa Cruz County-Landfill Gas
Sunrise-CC
Sunrise-CT
Wellhead-Fresno
Wellhead-Gates
Wellhead-Panoche
Williams 1, Prod B1
Williams 2, Prod B2
Williams 3, Prod A
Williams, Prod D
GWF-Phase I, II
GWF-Phase III

In addition, the Demand Reserve Purchase Agreement with the CPA was amended; three new contracts under the Interim Procurement Order were negotiated: 1) Calpine Geysers Geothermal, 2) Wheelabrator Biomass and 3) NDC Cogen; and four new short-term renewable contracts were added: 1) Dinuba, 2) Madera, 3) Sierra Pacific Sonora and 4) Sierra Pacific Terra Bella.

Contracts were renegotiated by the Department with input and acceptance from the Commission, the Office of the Governor, the Attorney General's Office, and the Electricity Oversight Board, with specific goals in mind. The goals of renegotiation included but were not limited to: (1) reduction of nondispatchable energy to shape supply to match energy demand; (2) shortening of contract terms to avoid purchases that sellers required but that were not vital to the state; (3) reduction of contract prices to just and reasonable levels and reduction of overall portfolio costs; (4) reduction of volumes of purchases in later years of contracts; (5) enhancement of the reliability of energy by improving contract terms; (6) positioning of contracts for possible assignment to other parties; (7) facilitation of contract administration by improving the Department's contractual rights, and; (8) targeting of projected Customer savings of at least 20 percent.

These renegotiations affect the Supplemental Determination by altering both the total contract costs to be recovered and the total retail sales made by the Department. Specifically, retail sales decreased from 44,063 GWh as estimated in the August 16, 2002 Determination (which also did not include contract allocations subsequently set forth by the Commission) to 42,113 GWh in this Determination (including the impact of contract allocations). The primary factors influencing the change in retail sales are the renegotiation of contracts and the load and resource changes described in the Department's testimony provided to the Commission as part of the proceeding to allocate the August 16, 2002 Determination. The increase in contract costs is the principal component of the increase in total power costs from $4.12 billion as estimated in the August 16, 2002 Determination, to $4.628 billion in this Determination. That increase is primarily the result of increased fuel prices discussed below.

Contract costs are affected by several variables, none of which can be entirely isolated. Contract costs have changed from the August 16, 2002 Determination due to renegotiation of contracts (which alter fixed costs, variable costs, and expected dispatch volumes), changes in URG assumptions which alter expected dispatch volumes described later, and changes in fuel prices.

FUEL COSTS

The per-unit price of natural gas has increased significantly since the forecast utilized in the August 16, 2002 Determination. Recent aggregate price levels, weather, and gas well drilling activity are the three key factors accounting for the change between the forecast used in the August 16, 2002 Determination (which was developed in March 2002) and the March 2003 gas price forecast (which is being used for this Supplemental Determination). Table E-1 below illustrates the changes in natural gas price forecasts used for the August 16, 2002 Determination and this Supplemental Determination.

Table E-1 Natural Gas Average Price Forecast (at the Henry Hub Delivery Point) (in $/MMBtu)		
	March 2002 Forecast	March 2003 Forecast
2003	3.01	5.30
2004	2.96	4.17
2005	2.85	3.69

Based on the record warm winter in 2002, the March 2002 forecast used about 10% fewer degree-days than normal. The key impact was that the season ended with 1.5 Tcf of gas in storage, resulting in approximately 700 Bcf that did not need to be injected last summer. Net storage activity after controlling for weather shows less gas injected per degree-day and more gas withdrawn per degree-day, suggesting tighter supply/demand balance across the U.S.

Based on the U.S. Energy Information Administration's report of 2002 production, which indicated flat production compared to the prior year, the well depletion assumptions behind the drilling variable were recalibrated to the 2002 data. This resulted in an additional 1,800 wells being required in almost all forecast years, increasing commodity prices by approximately $0.43 per MMBtu.

Increased gas prices impact the Department's revenue requirement in a number of ways, including increased contract costs for those contracts that have variable fuel costs (tolling arrangements), potential increases or decreases in dispatch and retail sales volumes for those contracts that have variable fuel costs, potential increases in dispatch and retail sales volumes for those contracts that do not have variable fuel costs (fixed price, dispatchable contracts), and potential increases in retail sales volumes for those contracts that do not have variable fuel costs (fixed price, must take contracts). Thus, the increased fuel cost component of the Department's power supply contract costs are the primary factor for the increase in total power costs from $4.12 billion (as estimated in the August 16, 2002 Determination) to $4.628 billion in this Supplemental Determination.

WAPA TREATMENT

In developing this Supplemental Determination, the Department has modeled power sales and purchases between PG&E and WAPA as a bilateral contract obligation of PG&E. This method of modeling has been utilized consistently by the Department since 2001, and the Department continues to believe that it is the appropriate way to account for this transaction. As a bilateral contract obligation, the transaction reduces total energy from URG available to serve retail customers. This reduction correspondingly increases the net short.

During 2001, 2002 and early 2003, PG&E excluded the amount of power it sold to WAPA from the amount of Department power that served as the basis for determining the amount of Power Charges remitted to the Department. Because the Department includes all power delivered to PG&E's service area in the retail sales figures used in its revenue requirement determinations, the per unit Power Charges determined by the Commission have also presumed the same level of retail sales. Thus, Power Charges for the PG&E service area have been set accordingly. When lower retail sales (without the WAPA volumes) are used as the basis for remittances, there is an undercollection of Power Charge Revenue by the Department.

On March 6, 2003, the Department sent a letter to the Commission on the subject of: "WAPA--Under-remittance associated with energy deliveries to retail customers in the service territory of Pacific Gas and Electric Company."[6] This letter highlighted the adverse consequences associated with this under-remittance and requested that the Commission "take any necessary steps to ensure the Department receives appropriate remittances from all energy delivered to retail customers in PG&E's service territory."

As of March 31, 2003, according to PG&E's most recent 10Q filing with the Securities Exchange Commission released on May 13, 2003, PG&E has accrued a $539 million (pre-tax) liability for pass-through revenues to the Department.

Although the Department presently is not in position to determine the precise amount and timing of receipt of the moneys to be received from PG&E, it assumes for purposes of this 2003 Supplemental Determination, that at least $539 million will be received by July 1, 2003. Any changes due to variances from this assumption would be accounted for outside the parameters of this Supplemental Determination. After the Department receives this remittance from PG&E, the funds are projected to be available for payment of Department Costs, in lieu of Power Charge Revenues from current power sales. As a result, $539 million of the reduction in the Department's 2003 revenue requirement is necessarily expressly conditioned on the actual receipt by the Department of remittances from PG&E for WAPA volumes through and including the first quarter of 2003. No change in Department Charges based on that portion of the revenue requirement reduction may be effective until such remittances have been actually received by the Department.

DIRECT ACCESS COST RESPONSIBILITY SURCHARGE

At the time of submittal of the August 16, 2002 Determination, Direct Access and departing load cost responsibility was an unresolved issue. On November 13, 2002, the Commission released Decision 02-11-022, enacting a Cost Responsibility Surcharge for Direct Access customers, that, in part, requires certain Direct Access customers to pay Department Bond and Power Charges going forward. Subsequently, the Commission in Decision 02-12-045 requested the Department address Direct Access in a Supplemental Revenue Requirement filing.

Bundled customer Bond and Power Charge responsibility is reduced dollar-for-dollar with Bond and Power Charge payments by Direct Access customers. Payments by Direct Access customers serve to reduce bundled customer payments to the Department, but do not affect the Department's overall revenue requirement. The Department purchases the same amount of energy on behalf of bundled customers, whether or not Direct Access

[6] March 6, 2003 memorandum to Honorable Geoffrey F. Brown, Commissioner and Honorable Loretta M. Lynch, Commissioner from Peter S. Garris, Deputy Director, Department of Water Resources

customers pay a portion of the cost. The Department has received $14 million in Power Charge Account revenues from Direct Access customers through March 2003.

CASH RESERVE LEVELS (OPERATING ACCOUNT AND OPERATING RESERVE ACCOUNT)

Cash reserves are maintained by the Department to protect the Power Charge Accounts and the bondholders against reasonable levels of measured volatility in expenses and revenues from foreseeable and quantifiable risks. The Operating Reserve Account is required by the Bond Indenture to be maintained at a level determined by the Department as described in the August 16, 2002 Determination and incorporated herein by reference. In the August 16, 2002 Determination, the ORAR was determined to be $777 million, based on the then applicable test. Now that the Department is no longer acquiring the residual net short, the ORAR is "the greater of (i) the largest aggregate amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any consecutive seven (7) calendar months commencing in [the] Revenue Requirement Period, and (ii) 12% of the Department's projected annual Operating Expenses for [the] Revenue Requirement Period [but] not less than [12%] of the Department's Operating Expenses for the most recent twelve (12) calendar month period", taking into account a range of possible future outcomes. Based on the sensitivity analysis described later in this section, the ORAR is now determined by the Department to be $630 million.

At the time of the August 16, 2002 Determination, the Department was still procuring the residual net short. While the August 16, 2002 Determination did not include power costs (other than for ancillary services) directly related to the procurement of the residual net short, the Bond Indenture required that a targeted minimum Operating Account balance (the Minimum Operating Expense Available Balance) be $1.0 billion until such time that the Department no longer procured the residual net short. Now that the Department no longer procures the residual net short the MOEAB is "the maximum amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any one calendar month during that Revenue Requirement Period . . . 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." This amount is determined by the Department to be $348 million.

HYDROELECTRIC CONDITIONS IN CALIFORNIA AND THE PACIFIC NORTHWEST

Hydroelectric conditions in California and the Pacific Northwest have changed since the August 16, 2002 Determination. In consideration of the potential impact, the Department has reviewed its hydroelectric assumptions, and has updated its forecast to reflect current expected hydroelectric conditions in both geographic areas.

In the August 16, 2002 Determination, hydroelectric facilities in California and the Pacific Northwest were derated by 5 percent for 2002, and were expected to return to a normal water year in 2003.

Utilizing DWR's California Water Supply Outlook runoff forecast, the California statewide forecast has been modified. The current forecast for California is 95 percent of normal annual hydroelectric production in 2003.

For the Pacific Northwest, the Department utilized the National Weather Services Northwest River Forecast Center runoff forecast for The Dalles, March 3, 2003 Early Bird Forecast. The updated forecast is 73 percent of a normal year in 2003.

Both California and the Pacific Northwest are assumed to be at 100 percent of normal hydroelectric production in 2004.

OTHER PROPOSED CHANGES RECEIVED FROM PARTIES BY DECEMBER 30, 2002

PG&E, SCE, SDG&E and CLECA have submitted inputs for the Department's consideration relative to this Supplemental Determination, in response to Decision 02-12-045.

PG&E's comments addressed ancillary services, Direct Access migration, the reduction of reserve requirements, and certain changes to modeling assumptions. Several of these issues have been discussed in this Supplemental Determination. Other areas brought forth by PG&E were Diablo Canyon capacity and availability, bilateral contract capacity and energy, the need to model the Etiwanda Power Plant as a part of PG&E's URG, the incorrect modeling of the Potrero Power Plant as a part of PG&E's URG, self-generation load assumptions, WAPA modeling and the incorrect modeling of the San Juan 3 Power Plant as a part of SCE's URG. Each of these issues was specifically addressed in the testimony of Mr. Frank Perdue of Navigant Consulting provided on behalf of the Department during the Commission's hearings addressing allocation of the August 16, 2002 Determination. The production simulation analysis underlying this Supplemental Determination includes revisions partly based on such comments.

SENSITIVITY ANALYSIS

The Rate Agreement requires the Department to evaluate its costs and cash flows on a monthly basis and to file revised Retail Revenue Requirements with the Commission 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 a revised Retail Revenue Requirement filing, 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 APA determination of its modified revenue requirement, file and initiate the Commission process regarding the new revenue requirement and allocation of costs among the 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 lag period, the Department must maintain reserve funds 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 targeted reserve fund 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, URG production levels, changing natural gas prices, and Department contract operations, among other factors.

To assess the adequacy of targeted reserve fund levels, the Department and its consultants have prepared an additional assessment of cash flow projections based on changes in certain key expense and operating assumptions (the "Stress Case"). The Stress Case considered in this assessment reflects a sampling of groups of changes in key assumptions that could affect the volatility of Department expenses and revenue receipts. The Stress Case is not intended to reflect all possible scenarios, nor is it intended to reflect only those most likely to occur. For the Stress Case, a market simulation was performed to generate revised net short requirements and associated power supply costs. This revised forecast was 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").

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

Higher costs are driven primarily by increased fuel costs. This Stress Case utilizes a natural gas price forecast that is twice the level of the Base Case forecast. Lower Customer sales by the Department are driven primarily by a decrease in the net short, which can occur as a result of increased URG and/or decreased Customer load. In this case, URG is increased by assuming California hydroelectric production at 100 percent of normal in 2003 and 115 percent of normal for 2004, and Pacific Northwest hydroelectric production at 85 percent of normal in 2003 and 115 percent of normal for 2004.

Lower loads are estimated in this case by assuming cooler-than-normal summers during 2003 and 2004, and by assuming increased non-programmatic conservation. The level of decreased Customer load due to temperature variation is simulated by decreasing the Base Case load forecast for 2003 and 2004 by three percent of total monthly load for June and July, and by five percent of total monthly load for August and September. 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 2003 and two percent in 2004. 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.

F. Just and Reasonable

This section explains the Department's reasons for determining that this Supplemental Determination is just and reasonable, and the process leading to the rendering of this determination.

BACKGROUND

The August 16, 2002 Determination provided extensive material leading to the determination by the Department that the August 16, 2002 Determination was just and reasonable. That information is incorporated in this Supplemental Determination by reference and will not be repeated herein.

Subsequent to August 16, 2002, new information became available to the Department, which influenced the Determination of Revenue Requirements. Such new information, either provided by the IOUs, as a result of experience from actual transactions or emanating from a change in key assumptions, or the Department's own operating results, has led to this Supplemental Determination.

The Commission Decision 02-12-045, rendered December 17, 2002, requested the Department reassess certain assumptions and requested the Department provide a supplemental determination. Decision 02-12-045 provided opportunity for interested parties to submit updated information to the Department for consideration in making a Supplemental Determination. The IOUs, and other parties, did submit proposed revisions and/or comments to the Department.

All information and comments submitted were reviewed and have been considered in this Supplemental Determination.

On February 13, 2003, the Commission held a workshop involving the IOUs, the Department and the Commission's Energy Division, with the purpose of discussing various assumptions. The Department identified additional information needed from the IOUs, to enable it to assess the need for a supplemental determination. Additional information was provided by the IOUs in February, 2003.

Information provided by PG&E, subsequent to the publication of the August 16, 2002 Determination, has been reviewed in depth and was incorporated as appropriate. The issues raised by PG&E were discussed in testimony presented before the Commission in October 2002, and are included in the official transcript of those hearings. The PG&E information is summarized in Section E, and the detail is a part of the Administrative Record of this proceeding and is referenced in Section G.

Decisions at the Commission, such as the allocation of contracts and the issuance of Servicing Orders have been considered. A significant issue at the time of the August 16, 2002 Determination was the pending transition of responsibility for the procurement of the residual net short from the Department to the IOUs. The anticipated ancillary service and other ISO costs were included in the Department's August 16, 2002 Determination due to issues regarding the timing and effectiveness of the proposed transition. Subsequent action by the Commission, and the actual transition on January 1, 2003, have enabled the Department to modify its position and eliminate the need for funding ancillary services costs in 2003, other than funds required to pay costs accrued in 2002.

A significant factor in this Supplemental Determination is the increase in fuel prices. This increase, discussed in Section E of this Determination, reflects market realities. The price of natural gas has increased significantly leading to an upward revision in this Supplemental Determination.

PUBLIC PARTICIPATION IN THE SUPPLEMENTAL DETERMINATION

The Department noticed and published its Proposed Supplemental Determination of Revenue Requirements on June 2, 2003 (the "Proposed Supplementary Determination"). The Department provided adequate and reasonable time for review with comments due no later than June 23, 2003.

Under the regulations promulgated by the Department to allow for adequate public review and comment, a final determination by the Department that the Proposed Supplemental Determination is just and reasonable can only be made after the Department's administrative process is complete.

The Department made the administrative record underlying the Proposed Supplemental Determination available for inspection on June 2, 2003. The Department provided PROSYM information to the IOUs on June 6, 2003, and after resolving critical confidentiality issues expressed by the IOUs, the Department provided the Financial Model underlying the determination on June 16, 2003. To aid the IOUs in their review of the material supporting the Proposed Determination, the Department and its consultant conducted face to face meetings, telephone conferences, and responded to specific electronic mail questions from each of the IOUs.

On June 23, 2003, comments were provided by each of the IOUs. No comments were received from other parties. The comments are included in the administrative record and are referenced in Section G. The comments are available for viewing at the CERS office in Sacramento, CA.

JUST AND REASONABLE DETERMINATION

The Department has reviewed and considered each comment received.

Partly as a result of the comments regarding administrative and general cost, the Department has provided in Section C, an expanded explanation of the details of the factors contributing to the increase in cost.

Partly in response to comments regarding revenues relating to WAPA volumes, the Department has discussed the possibility funds may not be received on July 1, 2003, as modeled, and has discussed some of the reasons for the assumption in the highlights of the Supplemental Determination, and in the assumptions contained in Section E.

The Department's review of all comments provided, including the two referenced above identified no substantial or significant errors or omissions, and has identified no reason to make substantial or significant change to the Determination. Further detail relative to the Department's review and assessment of the comments may be found in Section I.

After assessing all comments and any potential change resulting from any and all comments, the Department has determined the Supplemental Determination of Revenue Requirement for the period of January 1, 2003, through December 31, 2003, is just and reasonable.

G. Reference Index of Materials Upon Which the Department Relied to Make Determinations

Quasi-Legislative Record of Revenue Requirement Reasonableness Determination

Determination of Revenue Requirements Dated August 16, 2002, Including Specifically Appendix 3, entitled Reference Index of Materials Upon Which the Department Relied to Make Determinations

Commission Decision 02-12-045 "Opinion Adopting Interim Allocation Of The 2003 Revenue Requirement Of The California Department Of Water Resources", dated December 17, 2002

Commission Decision 02-12-052 (Order Correcting Error) issued on December 17, 2002

Commission Decision 03-02-031, dated February 13, 2003

Commission Decision 02-09-053 dated September 19, 2002

PROSYM, a price forecasting and market simulation tool

PG&E, SCE, SDG&E and the California Large Energy Consumers Association (CLECA) submitted assumptions for the Department's consideration in a supplemental determination

Additional input from the IOUs received on February 24, 2003

Renegotiated Power Contracts

Alliance SRA A	Wellhead-Fresno
Alliance SRA B	Wellhead-Gates
Capital Power-BioMass (terminated)	Wellhead-Panoche
Clearwood-Geothermal	Williams 1, Prod B1
PGE Trading-Wind	Williams 2, Prod B2
Santa Cruz County-Landfill Gas	Williams 3, Prod A
Sunrise-CC	Williams, Prod D
Sunrise-CT	GWF-Phase I, II
	GWF-Phase III

New Contracts Under the Interim Procurement Order

Calpine Geyser Geothermal	Wheelabrator Biomass
NDC Cogen	

Amended Demand Reserve Purchase Agreement

Power Authority

New Short Term Renewable Contracts

Dinuba	Sierra Pacific, Sonora
Madera	Sierra Pacific, Terra Bella

U.S. Energy Information Administration's report of 2002 production (gas)

CPUC Decision 02-12-069, dated December 19, 2002; regarding Operating Orders between DWR and IOUs

March 6, 2003 memorandum to Honorable Geoffrey F. Brown, Commissioner and Honorable Loretta M. Lynch, Commissioner from Peter S. Garris of the Department, on the subject of: WAPA--Under-remittance associated with energy deliveries to retail customers in the service territory of Pacific Gas and Electric Company

CPUC Decision 02-11-022, dated November 13, 2002 enacting a cost responsibility surcharge for direct access customers

DWR's California Water Supply Outlook runoff forecast, dated February 1, 2003

National Weather Services Northwest River Forecast Center runoff forecast for The Dalles, March 3, 2003 Early Bird Forecast

Testimony of Mr. Frank Perdue of Navigant Consulting, on behalf of DWR, during the CPUC hearing process on the August 16 Revenue Requirement, October 3 and 4, 2002

Transcript of hearings conducted by ALJ Allen on October 2, 3, and 4, 2002

State of California Department of Water Resources Power Supply Revenue Bonds (documentation):

Volumes 1 – 7, Dated October 30, 2002
- $1,000,000,000 Series 2002B
- $2,750,000,000 Series 2002C
- $ 500,000 000 Series 2002D

Volumes 1 – 4, Dated November 14, 2002
- $6,313,500,000 Series 2002A
- $ 700,000,000 Series 2002E

CPUC Decision 02-08-071, dated August 22, 2003

CPUC Decision 02-09-045, dated September 19, 2002

CPUC Decision 02-10-035, dated October 17, 2002

CPUC Decision 02-10-062, dated October 24, 2002

CPUC Decision 02-10-063, dated October 24, 2002

CPUC Decision 02-10-067, dated October 24, 2002

CPUC Decision 02-11-026, dated November 7, 2002

Peter S. Garris Memo to Paul Clanon, CPUC, dated November 8, 2002; Submittal of "more precise" bond revenue requirement after bond placement

CPUC Decision 02-11-074, dated November 21, 2002

CPUC Decision 02-12-027, dated December 5, 2002

ALJ Allen and ALJ Pulsifer Joint Ruling Regarding the process to implement direct access CRS, dated December 10, 2002

CPUC Decision 02-12-074, dated December 19, 2002

CPUC Decision 02-12-071, dated December 19, 2002

CPUC Decision 02-12-072, dated December 19, 2002

CPUC Decision 02-12-082, dated December 30, 2002

CPUC Decision 03-02-032, dated February 13, 2003

CPUC Decision 03-20-036, dated February 13, 2003

CPUC Decision 03-02-072, dated March 4, 2003

CPUC Decision 03-05-034, dated May 8, 2003

CPUC Decision 03-05-036, dated May 8, 2003

Peter S. Garris letter to Paul Clanon, CPUC, dated May 14, 2003; regarding remittance of Direct Access CRS

PG&E 1st Quarter Report to the Securities and Exchange Commission (10Q)

Pacific Gas and Electric Company's Comments on the California Department of Water Resources' Proposed Supplemental Determination of Revenue Requirements for the Period January 1, 2003 Through December 31, 2003, dated June 23, 2003

Southern California Edison Company's Comments on the California Department of Water Resources' Proposed Supplemental Determination of Revenue Requirements for the Period January 1, 2003 Through December 31, 2003, dated June 23, 2003

San Diego Gas and Electric Company's Comments on the California Department of Water Resources' Proposed Supplemental Determination of 2003 Revenue Requirement, dated June 23, 2003

H. Results of Bond Sales

RESULTS OF BOND SALES

Bond pricing and initial interest rate bidding was completed November 7, 2002, and the last series closed on November 14, 2002. The ultimate bond structure utilized reduced principal amortization in 2004 by $200 million from the August 16, 2002 Determination, thereby resulting in a lower 2003 bond revenue requirement. The Bond Revenue Requirement for 2003, on a cash basis, is $745 million compared to $1.142 billion included in the August 16, 2002 Determination.

The amount of revenues required to pay Bond Related Costs (the defined term "Bond Related Costs" technically means the required deposits to the Bond Charge Accounts) can be calculated as the sum of:

(1) Debt service payments; and

(2) Changes to Bond Charge Account balances.

Revenues available to pay Bond Related Costs include:

(1) Interest earned on Bond Charge Account balances;

(2) Transfers from Power Charge Accounts; and

(3) Bond Charge Revenues from Retail End Use Customers and Direct Access Customers.

Table H-1 provides a quarterly summary of expected Bond Related Costs and related Revenues for the 2003 Revenue Requirement Period.

TABLE H-1
POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE:
RETAIL CUSTOMER BOND CHARGE CASH REQUIREMENT

Line	Description	Amounts for Revenue Requirement Period				
		2003 - Q1	2003 - Q2	2003 - Q3	2003 - Q4	Total
1	*Bond Charge Accounts Expenses*					
2	Debt Service Payments	36	224	36	239	535
3	Other Bond Charge Accouts Expenses	-	-	-	-	-
4	Net Changes to Bond Charge Account Balances	121	(45)	189	(34)	231
5	**Total Bond Charge Accounts Expenses**	**157**	**179**	**225**	**205**	**765**
6	*Bond Charge Accounts Revenues*					
7	Interest Earnings on Bond Charge Account Balances	4	-	16	-	21
8	Revenue Bonds Net Proceeds	-	-	-	-	-
9	Net Transfers from/(to) Power Charge Accounts	-	-	-	-	-
10	Retail Customer Bond Charge Revenue Requirement	152	179	208	205	745
11	**Total Bond Charge Accounts Revenues**	**157**	**179**	**225**	**205**	**765**

During the 2003 Revenue Requirement Period, the Department projects that it will incur the following costs related to Bond Requirements: (a) $535 million for payments to meet Debt Service requirements and (b) $231 million for Changes to Bond Charge Account balances, resulting in total Bond Charge Account expenses of $765 million.

Funds to meet these requirements are provided from (a) $21 million in Interest Earnings on Bond Charge Account balances; (b) no net transfers from Power Charge Accounts; and (c) $745 million from Bond Charge Revenues from Retail End Use Customers and Direct Access customers.

SUMMARY OF CHANGES IN BOND CHARGE COSTS AND REVENUES FROM AUGUST 16, 2002 DETERMINATION

Upon the issuance of the Power Supply Revenue Bonds in October and November 2002, the Department was able to reduce its projections of Bond Related Costs that were factored into Bond Charges by the Commission for 2003. Bond Charge Costs decreased by $395 million. This was due to the following factors:

Reduced 2004 Bond Principal Amortization

The primary factor for decreasing the 2003 bond revenue requirement is the reduction of approximately $200 million in the Department's May 1, 2004 principal amortization and changes in the Bond Indenture that allowed the Department to delay the beginning of its monthly accruals for the May 2004 principal payment from February 2003 until August 2003. The bond principal deferment from 2004 was spread over the remaining years of the bond issue's term. The reduction in principal maturing in 2004 and the delay in the start date of accruals for the principal payment until later in 2003 results in a lower required year-end balance in the Bond Charge Payment Account.

Lower Than Projected Interest Rates

The interest rates established for the Power Supply Revenue Bonds issued in October and November 2002 were lower than the rates projected by the Department in the August 16, 2002 Determination. The average projected rate for all bonds in the August 16, 2002 Determination was 5.38 percent per annum. The outcome achieved by the Department in its October and November 2002 bond sales resulted in an average projected rate for revenue requirement purposes of 4.80 percent per annum. This improvement was not solely the result of a reduction in general market interest rate levels; it also reflected the Department's success at securing municipal bond insurance and bank credit enhancement for the bonds. The additional insurance capacity and bank letters of credit and liquidity support allowed the Department to sell more of its debt at significantly lower interest rates. The improvement in interest rates and the enhanced bond structure resulted in a reduction in projected gross interest costs in 2003 of more than $50 million.

Smaller Than Projected Bond Issuance

Another impact of the lower interest rates achieved by the Department was a reduction in the funding requirements for the Bond Charge Accounts. The largest reduction in funding was for the Debt Service Reserve Account. In the August 16, 2002 Determination, the Department estimated that the initial deposit to the account would be $974 million. The actual funding requirement upon the issuance of the bonds was $927 million. The reduction in the overall bond size had the effect of lowering the interest component of the Department's 2003 debt service.

I. Comments Received and the Department's Assessment

This section provides a summary of the comments provided by the IOUs, and the Department's assessment of those comments. Copies of the comments are available for review at the CERS office in Sacramento, CA.

PG&E offered comments in the following areas:

1. Natural gas prices and costs are high;

   Assessment: In the assumptions in Section E, the Department provides an explanation of the costs leading to the increase, and additional detail of the costs are included in confidential information pertaining to PG&E. This information has been provided to PG&E.

2. Hydroelectric power availability for 2003 is to low;

   Assessment: The Department relied upon updated and published information available in March 2003, as noted in the assumptions in Section E, and identified in Section G. The possibility of changes to any forecast exists. It is the Department's assessment however, that any subsequent update will not result in a significant or material change in the 2003 Supplemental Determination. Forecast changes for 2004 will be reflected in the Revenue Requirement Determination for that year. Actual results for 2003 will be taken into account in subsequent future revenue requirement determinations.

3. Generation from renewable contracts should be addressed separately and the Supplemental Determination contains no indication they are properly included;

   Assessment: The IOUs were provided with PROSYM data relative to their own confidential contract related information that identifies the contracts and the allocation of such contracts.

4. Sizing of reserves not justified;

   Assessment: The methodology for the sizing of the reserve requirements is explained in detail in the Supplemental Determination and is essentially the same as the methodology described and supported by the record relating to the August 16, 2002 determination, including the record of discussions with the bond rating agencies. The Bond Indenture and related documents and the declarations concerning such discussions are included in the Administrative Record and are available for viewing at the CERS office in Sacramento, CA. The financial information needed to calculate the reserves, and the actual calculations are contained in the Financial Model data underlying the Supplemental Determination.

5. Reasonableness of Contract Renegotiations;
   The Supplemental Determination contains no analysis of the benefits received from the renegotiations of contracts, or discussion of alternatives. In the State Auditor's report dated April 3, 2003 reference was made to such analysis.

   Assessment: The renegotiated contracts are identified in the Supplemental Determination, and the contracts themselves are readily available on the Department's web site (http://www.ca.gov/cers). Specific details relative to individual settlement negotiations are confidential including any analyses of the reasonableness of amended terms. The participation in those negotiations of parties actively representing the interests of ratepayers, and the approval by those parties of the renegotiated contracts supports the reasonableness of the amended terms, under the circumstances existing at the time.

6. The lawfulness of costs associated with new programs or contracts;

   Assessment: The Department has complied with the California Water Code in the renegotiation of contracts, has identified all contracts in the Supplemental Determination, and has provided significant detail regarding each contract in the PROSYM data underlying the Supplemental Determination. The Department has not entered into any new contracts for power since December 31, 2002.

7. WAPA true-up should be linked to implementation of the reduction in the 2003 revenue requirement;

   Assessment: The Department has expressly stated that the portion of the reduction in the 2003 revenue requirement relating to remittance by PG&E of Power Charges for WAPA volumes is conditioned on the actual receipt by the Department of remittances from PG&E for WAPA volumes through and including the first quarter of 2003. No change in Power Charges based on that portion of the revenue requirement reduction may be effective until such remittances have been actually received by the Department. As described above, the timing and amount of such remittances is the subject of pending proceedings before the Commission.

8. A portion of the WAPA true-up is associated with 2001-2002 and must be included in any true-up of those remittances;

   Assessment: In its accounting for the Power Program, the Department will include the detail necessary to determine the years to which any remittances with respect to WAPA volumes are attributable. The Commission will determine the timing and process to address any true-up of the allocation of actual costs among the IOUs.

9. Remittance methods.

   Assessment: Any deviation between the amounts remitted for energy on a forecast basis and the results of actual operations will be taken into account in subsequent revenue requirement determinations.

SCE commented in the following areas:

10. For calculation of reductions, the Department should have used information contained in CPUC Decisions issued subsequent to the August 16, 2002 Determination;

    Assessment: The August 16, 2002 Determination, filed with the Commission on August 19, 2002 was the result of the Department's public review process. Changes received subsequent to that determination were reviewed in testimony in October, and the Commission decided to exclude new data from consideration since the public had not had adequate opportunity to review changes. The Interim Decision 02-12-045, adopted December 17, 2002, was based on the August filing. It is recognized that a number of decisions have been issued that have an impact on the Supplemental Determination. The comparison made allows for a consistent starting point. The numbers included in the Supplemental Determination, and the explanations provided within reflect, within the public process, the changes that have been made. The comparison to the August 16, 2002 Determination was included for identification of significant changes, and does not effect the actual Supplemental Determination.

11. SCE identified several modeling errors, specifically in the modeling of SCE's transitional contracts;

    Assessment: This Supplemental Determination utilized the August 16, 2002 Determination as the starting point, and addressed certain specific changes identified subsequent to that Determination. In the December 2002 comments provided by the IOU, and again in February 2003, there was no indication of the modeling discrepancies now being identified. None-the-less, the Department has reviewed the new information and has determined there are no significant or material changes impacting the 2003 period. Changes in modeling assumptions will be incorporated in future revenue requirement determinations, as appropriate.

12. A&G costs should not increase;

    Assessment: The reasons underlying the increase in Administrative and General costs are explained in Section C.

13. WAPA payment calculation should be calculated by DWR rather than taken from PG&E financial data;

    Assessment: In Section E, the Department states that it is not in a position to identify precise figures at this time. This section continues on to state the $539 million accrued by PG&E is considered the least amount that will be received by the Department.

14. Impact of delay in receipt of WAPA payment beyond July 1, 2003;

    Assessment: In the establishment of the Supplemental Determination, the Department has provided the revenue requirement for 2003, with an attempt to identify when, on a monthly basis, transactions will occur. The Department is unable to predict with certainty when PG&E will remit amounts owing from WAPA volumes. The impact on the revenue requirement of a short-term delay, however, is minimal, in terms of the total revenue requirement. The timing of payments from PG&E to the Department will impact the allocation process to be determined by the Commission. In addition, the Department has been explicit in this Supplemental Determination that remittances by PG&E on WAPA volumes are not available for payment of Department Costs in lieu of Power Charge Revenues from current power sales until such remittances are actually received by the Department.

15. Managing DWR-related rate changes

    Assessment: This Supplemental Determination by the Department conveys the amount of the Department's revenue requirement. In accord with the terms of the Rate Agreement, it is the Commissions responsibility to allocate the Departments requirements amongst and between the IOUs.

SDG&E Comments:

16. The load used by DWR is higher than that recently provided by SDG&E due to the inclusion of transmission losses;

Assessment: This Supplemental Determination utilized the August 16, 2002 Determination as the starting point, and addressed certain specific changes identified subsequent to that Determination. In the December 2002 comments provided by the IOU, and again in February 2003, there was no indication of the modeling discrepancies now being identified. Nonetheless, the Department has reviewed the new information and has determined there are no significant or material changes impacting the 2003 Revenue Requirement Period. Changes in modeling assumptions will be incorporated in future revenue requirement determinations, as appropriate.

17. DWR should further identify components of its increase in contract costs;

    Assessment: Information provided by the Department includes costs by contracts and may be compared with data previously provided. The Department also identifies the cost of natural gas as a primary factor in the cost increase. In the assumptions in Section E, the Department provides an explanation of the costs leading to the increase. Additional details of the costs are included in confidential information pertaining to SDG&E, provided to SDG&E.

18. A&G costs are too high and should be explained further;

    Assessment: The reasons underlying the increase in administrative and general costs are explained in Section C.

19. The 2001 – 2002 true-up should be expedited;

    Assessment: This Supplemental Determination is prepared on a cash basis; therefore, funds are trued up for the determination of the Department's needs. The Commission will determine the timing and process to address the true-up allocation of historical costs amongst and between the IOUs.

20. Williams contract is correctly modeled and SDG&E agrees with the removal of Ancillary Services costs;

    Assessment: No comment.

21. DWR should explain what load changes occurred;

    Assessment: The Department provided adequate PROSYM and Financial Model data to allow SDG&E to identify and determine the changes related to its operations.

22. DWR may have excluded certain contracts allocated to SDG&E and should clarify whether they are included in the model;

Assessment: Three of the four contracts identified by SDG&E by name are included in the contract allocation data provided to SDG&E. They are identified as: Morgan Stanley Group (MD_DWRS_1BB), Whitewater – Cabazon (CBZN_DWRS_1 1) and Whitewater – Hill (CBZN_DWRS_2 1). The forth contract SDG&E references as "Imperial Valley Resource Recovery". No contract with that name is included in our contract list and no contract of that name was provided by SDG&E in the data recently provided to the Department.

23. DWR contracts are modeled to serve statewide load, but should base projections on individual utility projections, and SDG&E suggests this should be adopted for the 2004 revenue requirement.

    Assessment: PROSYM modeling has been reviewed previously, is part of the administrative record, and is part of the significant material relied upon, identified in Section G.