Decision **DRAFT DECISION OF ALJ PULSIFER** **(Mailed 9/4/2001)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (E 3338-E) for Authority to Institute a Rate Stabilization Plan with a Rate Increase and End of Rate Freeze Tariffs.	Application 00-11-038 (Filed November 16, 2000)
Emergency Application of Pacific Gas and Electric Company to Adopt a Rate Stabilization Plan. (U 39 E)	Application 00-11-056 (Filed November 22, 2000)
Petition of THE UTILITY REFORM NETWORK for Modification of Resolution E-3527.	Application 00-10-028 (Filed October 17, 2000)

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I. Overview

This decision provides the revenue required to cover the costs of the California Department of Water Resources' (DWR) power purchase program, consistent with Assembly Bill 1 of the First Extraordinary Session, Stats. 2001, Ch. 4, hereafter referred to as AB1X. We approve charges that, when applied to sales of electricity by DWR, will enable DWR to recover its revenue requirement, as provided by AB1X. The charges we approve will remain in effect from September 15, 2001 to May 31, 2002.

On August 7, 2001 DWR submitted to the Commission its most recent revenue requirement of $12,600,386,000. This amount represents DWR total requirements until December 31, 2002. However, this order sets charges to meet those requirements until May 31, 2002. We anticipate that the Commission will act on a new order before June 1, 2002 to allow recovery of the remainder of DWR's revenue requirement as provided by AB1X. In addition, this decision does not cover the costs for certain demand-side management (DSM) programs that are not included as authorized costs under AB1X, as explained further below.[1]

The DWR charges designated in this decision provide DWR with sufficient revenues to recover its revenue requirement for AB1X authorized costs. Revenue to meet this requirement will be collected from customers in the service territory of the three major California electric utilities: Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas &

[1] See below, Section VIII.

Electric Company (SDG&E). We require each of the utilities to forward DWR revenues collected from retail customers based on a designated per-kWh charge as set forth in this decision.

We allocate the total DWR revenue requirement among each of the three major utilities' service territories, on a cost of service basis, as follows:

PG&E	$ 6,532,650,000
Edison	$ 4,017,786,000
SDG&E	$ 1,536,351,000

DWR has requested a uniform charge of 11.38 cents per kWh for each of the three utilities on a going forward basis. As described below in more detail, a cost-of-service approach to allocation among the customers of the respective utilities is more reasonable than a uniform "postage stamp" approach. The cost of service allocation approach we use results in a separate cents per kWh charge for customers in the service territory of each utility of 13.99 cents/kwh for PG&E, 10.03 cents/kwh for Edison and 9.02 cents/kwh for SDG&E.

We do not change retail rates for PG&E or Edison in today's order. We will address the need for any change in rates for SDG&E customers in order to meet DWR's costs of serving SDG&E customers in a separate decision that is being issued today. For Edison and PG&E customers, any need for a change in overall rates charged to customers as a result of this Decision approving charges enabling DWR to recover its revenue requirement in retail rates cannot be addressed until we issue our subsequent decision on utility retained generation (URG) issues.

With fixed retail rates and a fixed per kWh charge payable to DWR, there is, in effect, an amount that each utility is entitled to receive for its own account for the kWhs that it supplies to its retail customers. We will call this amount the "imputed utility rate." To the extent that the actual percentage of DWR sales to each utility's retail customers is either less than or exceeds the forecast percentage of DWR sales to those customers for any month, the customers' bills for that month will not reflect exactly the imputed utility rate for the kWhs the utility provides. However, it is not our intent that the utilities ultimately recover either more or less than the imputed utility rate for the kWhs they provide. We shall direct each of the three utilities to establish balancing accounts and to book into these accounts the difference between the imputed utility rate based on today's decision and the effective rate it has billed, multiplied by the number of utility-supplied kWh's billed at that effective rate. The balancing accounts shall be trued up, pursuant to a subsequent Commission order, no later than during the next update proceeding for DWR scheduled for February 2, 2002.

We note that the high retail electric rates now in effect in California reflect the exorbitant wholesale electricity costs caused by the crisis manufactured by wholesale electricity sellers and traders over the past year. These rates measure, in part, the terrible price California has had to pay to restore stability. It is our hope that the actions of DWR and the utilities, as well as the efforts of public and private parties involved in cases at the Federal Energy Regulatory Commission (FERC) and in the courts to reduce costs will be successful, and that we will be able to revisit the charges and allocations for DWR's revenue requirement that we approve today to be able to lower these charges in the future.

II. Related Actions

The timely implementation of the retail revenue requirement for DWR is one of the components necessary to support the sale of bonds as developed and structured by DWR and the Treasurer's Office to provide long term funding of DWR's procurement obligations. AB1X anticipates that bonds will be sold to enable DWR to repay the State's General Fund for monies that have already been expended on power purchases.[2] Under the structure of the transaction currently being under taken by the Administration and the State Treasurer, bond proceeds will also offset a portion of current and future procurement costs that would otherwise be charged to ratepayers in order to moderate the effect of wholesale electric power costs that continue at historically high levels by spreading their impact over time. The specific bond structure proposed by DWR and the State Treasurer combines the objectives of General Fund repayment and support for DWR operations.

In related actions, we are adopting Servicing Agreements between DWR and each of SDG&E and Edison, and a servicing order relating to PG&E. These decisions will provide for the utility services required by DWR to perform functions authorized by the Water Code.[3] The Servicing Agreements set forth the terms under which each utility will provide transmission and distribution of DWR power to electric customers, and provide billing, collection, and related services for AB1X-authorized power purchased by DWR. At the request of the Administration and the State Treasurer, we are also suspending direct access according to the mandates of AB1X.

Finally, we are adopting a Rate Agreement between DWR and the Commission as allowed by AB1X. The Rate Agreement establishes an irrevocable financing order, which the Administration and the State Treasurer

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[2] Water Code Section 80200(b)(4).

[3] *See* A.01-06-044, filed June 25, 2001 for Edison's Servicing Agreement, and A.01-06-039, filed June 22, 2001, for SDG&E's Servicing agreement. PG&E's proposed Servicing Agreement is being considered in this docket (A.00-11-038 et al.) as a result of DWR's letter of June 27, 2001 requesting that the Commission order PG&E to provide certain services to DWR.

state is required in order for the bond transaction currently being undertaken by the Administration and the State Treasurer to be completed. (*See* Water Code Section 80130.)

It should be apparent that several of these related decisions, particularly approval of the Rate Agreement, are driven by the specific bond structure proposed by DWR. The instant decision establishing charges to enable DWR to recover its costs as authorized by AB 1X does not fall so clearly into that category. The level of revenue requirement to be recovered is significantly driven by the bond structure, which includes certain specified reserve levels. However, bond structure and size is an issue exclusively committed to the discretion of DWR. As developed more fully below, this Decision represents an exercise of the Commission's traditional ratemaking authority for DWR electricity sales, as shaped and directed by the Legislature in AB1X.

III. Regulatory and Statutory Mandates Relating to DWR Power Procurement

The actions we take in today's order follow the statutory scheme that was enacted in response to emergency conditions confronting California's major electric utilities and their customers. On January 17, 2001, Governor Gray Davis issued a Proclamation that a "state of emergency" existed within California resulting from unanticipated and dramatic increases in the wholesale price of electricity.[4] The Governor's Proclamation stated that "unanticipated and dramatic increases in the price of electricity have threatened the solvency of California's major public utilities, preventing them from continuing to acquire

[4] The Governor's Proclamation was attached as Appendix A to Decision (D.) 01-01-061.

and provide electricity sufficient to meet California's energy needs." Governor Davis therefore ordered DWR to assume responsibility for procurement of a major portion of electric power resources for customers of California's three major electric utilities. On January 19, 2001 Governor Davis signed SB 7 from the First Extraordinary Session of 2001-2002 (SB7X). This bill directed DWR to procure electricity on an interim basis and appropriated $400 million for this purpose.[5]

Accordingly, DWR formally began procuring electric power on behalf of customers of the three major electric utilities on January 17, 2001.[6] DWR undertook to meet net short requirements[7] through a combination of contractual power purchases and spot market purchases, including purchases of ancillary services. DWR has also, from time to time, assumed responsibility for imbalance energy and Independent System Operator (ISO) charges.

On February 1, 2001, the California Legislature enacted AB1X, which added Division 27 to the California Water Code, sections 80000 et seq. AB1X authorized DWR to continue its power purchasing activity through December 31, 2002. Among other things, that statutory enactment provides the

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[5] SB 7X authorized DWR activities only for a period of twelve days in January.

[6] DWR had regularly engaged in electric purchase and sale activities in connection with the State Water Project for a number of years. In December 2000 it also apparently worked with the Independent System Operator (ISO) to fund ISO electricity procurement activities on an informal basis, using State Water Project moneys.

[7] The term "net short" came to be used to describe the difference between utility retail demand and the supply resources provided by the utility's own generation and committed power purchase contracts with qualifying facilities (QFs) and other suppliers.

following measures relating to DWR's procurement of power for California consumers:

- Authorizes DWR to purchase power and sell it to retail customers of PG&E, Edison, and SDG&E, as well as to customers of municipal utilities. (Water Code Sections 80100 and 801160.)
- Establishes the DWR Electric Power Fund in the State Treasury, into which are deposited all revenues payable to the department relating to power procurement, including proceeds from power sales, bond sales, appropriations and other sources. (Water Code Section 80200(b).)
- Authorizes DWR to sell bonds. (Water Code Section 80130.)
- Requires DWR to establish a revenue requirement to defray the costs of its activities and to communicate that revenue requirement to the Commission for recovery in retail electric rates. (Water Code Section 80134.)
- Allows DWR to recover its revenue requirement through charges for power established by the Commission after providing its revenue requirement to the Commission. (Water Code Section 80110.)

AB1X contains provisions to provide funds to DWR from revenues generated by applying charges to the electricity that it sells to the customers of the investor-owned utilities. Water Code Section 80002.5 states that "[i]t is the intent of the Legislature that power acquired under this division shall be sold to all retail end use customers served by electrical corporations, …." Water Code Section 80104 explains that "[u]pon the delivery of power to them, the retail end use customers shall be deemed to have purchased that power from the department. Payment for any sale shall be a direct obligation of the retail end use customer to the department."

AB1X assigns roles to the Commission and DWR respectively in establishing the terms of the relationship between DWR as interim power seller and the customers of the investor-owned utilities. The key provision of the statute is Water Code Section 80110, which provides in relevant part:

> 80110. The department shall retain title to all power sold by it to the retail end use customers. The department shall be entitled to recover, as a revenue requirement, amounts and at the times necessary to enable it to comply with Section 80134, and shall advise the commission as the department determines to be appropriate. Such revenue requirements may also include any advances made to the department hereunder or hereafter for purposes of this division, or from the Department of Water Resources Electric Power Fund, and General Fund moneys expended by the department pursuant to the Governor's Emergency Proclamation dated January 17, 2001. For purposes of this division and except as otherwise provided in this section, the Public Utility [sic] Commission's authority as set forth in Section 451 of the Public Utilities Code shall apply, except any just and reasonable review under Section 451 shall be conducted and determined by the department. The commission may enter into an agreement with the department with respect to charges under Section 451 for purposes of this division, and that agreement shall have the force and effect of a financing order adopted in accordance with Article 5.5 (commencing with Section 840) of Chapter 4 of Part 1 of Division 1 of the Public Utilities Code, as determined by the commission….

AB1X thus confirms that the Commission's authority as set forth in Public Utilities Code Section 451 applies to proceedings in connection with DWR's revenue requirements, except"any just and reasonable review" of its costs shall be "conducted and determined" by DWR. The California Constitution provides that the Legislature may confer additional authority on the Commission "unlimited by the other provisions of this constitution but consistent with this Article [XII]." (Article XII, Section 5.) In confirming the authority of the Commission to set charges and terms for DWR power sales pursuant to Public

Utilities Code Section 451 "for purposes of this division," the Legislature is acting within its powers, notwithstanding DWR's status as a state agency. The express grant of authority to the Commission under Section 451 "for purposes of this division" necessarily carries with it the authority to do "… all things necessary and convenient in the exercise" of its powers. (Public Utilities Code Section 701.)

Water Code Section 80110 provides that DWR is entitled to recover in rates amounts sufficient to enable it to comply with Section 80134, which are, under the bond structure currently being undertaken by the Administration and the State Treasurer, the revenues that may be pledged for support of bonds that DWR is authorized to issue pursuant to Section 80130. Section 80134 provides:

> 80134. (a) The department shall, and in any obligation entered into pursuant to this division may covenant to, at least annually, and more frequently as required, establish and revise revenue requirements sufficient, together with any moneys on deposit in the fund, to provide all of the following:
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> (1) The amounts necessary to pay the principal of and premium, if any, and interest on all bonds as and when the same shall become due.
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> (2) The amounts necessary to pay for power[8] purchased by it[9] and to deliver it to purchasers, including the cost of electric power and transmission, scheduling, and other related expenses incurred by the department, or to make payments under any other contracts, agreements, or

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[8] The term "power" is defined in AB1X as "…electric power and energy, including, but not limited to, capacity and output, or any of them." (Water Code Section 80010(f).)

[9] Prior to commencing any program of power purchases DWR is required to "… assess the need for power in the state in consultation with the Public Utilities Commission and local publicly owned electric utilities and electrical corporations in the state and such other entities in the state as the department determines are appropriate." (Water Code Section 80100(f).)

obligations entered into by it pursuant hereto, in the amounts and at the times the same shall become due.

(3) Reserves in such amount as may be determined by the department from time to time to be necessary or desirable.

(4) The pooled money investment rate on funds advanced for electric power purchases prior to the receipt of payment for those purchases by the purchasing entity.

(5) Repayment to the General Fund of appropriations made to the fund pursuant hereto or hereafter for purposes of this division, appropriations made to the Department of Water Resources Electric Power Fund, and General Fund moneys expended by the department pursuant to the Governor's Emergency Proclamation dated January 17, 2001.

(6) The administrative costs of the department incurred in administering this division.[10]

(b) The department shall notify the commission of its revenue requirement pursuant to Section 80110.

The role of the Commission under these two statutes, then, is to establish charges to recover the costs of authorized DWR activities, but not to assess the reasonableness of a particular cost, once it has been determined to be authorized by AB1X. Any assessment of the justness and reasonableness of the costs of DWR's authorized activities is to be "conducted and determined" by DWR consistent with Public Utilities Code Section 451.

In this decision we are establishing charges to recover the revenue requirement for DWR pursuant to Section 80110 as presented to us. These revenue requirements include forecasts and representations about future events, including multiple bond issuances with estimates of reserve requirements and

[10] Administrative costs are to be approved in the annual Budget Act. (Water Code Section 80200(c).)

interest rates that may or may not reflect actual conditions at the time the bonds are sold. We also assume along with the DWR the timing of such issuances. As appears more fully below, we intend to establish a mechanism for reconciling revenue requirements with costs, for rate setting purposes, to be implemented by the Commission before June 2002.

On an interim basis, the Commission has issued several orders in recent months to permit DWR to collect revenues for its power purchases. We made those decisions with limited information because of the urgent need to provide some revenue to DWR. Today's decision establishes charges based on a final DWR revenue requirement, based on more comprehensive modeling and information provided by DWR.

IV. Procedural Measures Leading to DWR Revenue Requirement Implemented in This Order

Until now, DWR has been relying on interim borrowing arrangements and interim measures approved by the Commission to finance its purchases of electric power as authorized by AB1X. The DWR revenue requirement represents the remaining amounts due from customers after taking into account the proceeds from the anticipated sale of long-term bonds. Timely implementation of the DWR retail revenue requirement is integral to the sale of the long-term bonds as developed and structured by DWR and the Treasurer's Office.

DWR projects that the bonds will be issued in the fall of 2001 in the principal amount of $12.5 billion to support long-term funding for its power procurement obligations. The bonds are projected to have a final maturity date of May 1, 2016. DWR states that the bond proceeds will be used to stabilize customers' rates over time, as a supplement to the retail revenue requirement collected in utility rates. During the period through December 31, 2002 and beyond, the proceeds from the bonds will reduce the revenue requirement related to power purchases for resale that must be collected from ratepayers. Future ratepayers will service the repayment of bond principal, together with accrued interest, in addition to paying for DWR power that they consume.

DWR sent a letter to the Commission on May 2, 2001, stating its initial estimated revenue requirement for recovering power purchase costs under AB1X. In that letter, DWR requested that the Commission "establish specific rates payable to the Department for power sold by the Department to retail end use customers within the State." The letter also stated that the rates established by the Commission "should be independent of rates payable by retail end use customers for power purchased by such customers from the utilities, and by law, must be sufficient in order for the Department to recover the revenue requirements attached hereto." (*Id.*) DWR stated that revenues resulting from such rates should be measured as a function of the amount of power sold by DWR, and not as a function of the amount of power sold by each respective utility. DWR specified the revenue requirement on a separately allocated and combined basis for the service territories for each of the three utilities. While DWR did not describe the basis by which the revenue requirement was allocated among the service territories for each of the three utilities, it offered to provide additional information as requested by the Commission in order to assist in its rate-setting function.[11] (*Id.*)

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[11] A copy of DWR's May 2, 2001 letter was appended to D.01-05-064 as Attachment B.

On June 18, 2001, PG&E filed a motion for expedited evidentiary hearings on the calculation, allocation, rate design and implementation of DWR's revenue requirement under AB1X. PG&E sought to consolidate the revenue requirement issues with the scheduled hearings to establish the utility retained generation (URG) revenue requirement in this docket. PG&E did not request a Commission hearing to review the reasonableness or the amount of DWR's revenue requirement, but rather to determine the allocation of DWR's revenue requirement among the utilities' service territories. A companion motion was filed by Edison on June 19, 2001, supporting PG&E's proposal, and emphasizing that the Commission's inquiry should determine whether existing retail rates are sufficient to cover both the DWR and utility related costs for electric power procurement.

The assigned Administrative Law Judge (ALJ) issued a ruling dated July 12, 2001, that denied these motions. Instead, the ALJ provided an opportunity for parties to file written comments on the DWR revenue requirement and allocation issues. Commissioner Geoffrey F. Brown sent letters dated June 18, 2001, and June 26, 2001, to the Director of DWR, Thomas M. Hannigan, seeking additional information to supplement the data provided in the May 2, 2001 revenue requirement letter referenced above. The ruling also provided notice and an opportunity for parties to review and comment on the DWR response to Commissioner Brown's letters. The ruling stated that a separate Commission decision would be prepared to address the DWR revenue requirement and allocation issues. These actions were prompted by the evident sense of urgency in moving forward with the Commission decisions that are predicates for the issuance of the bonds developed and structured by DWR and the Treasurer's Office.

DWR provided a written response to Commissioner Brown's letters by memorandum dated July 23, 2001. In its response, DWR submitted a revised estimate of its revenue requirement. This revised estimate also extended the forecast period from May 31, 2002 through December 31, 2002. The DWR July 23 memorandum, with supporting data submittals, was served on the parties as an attachment to a Joint Assigned Commissioners' Ruling (ACR) on July 24. Because the DWR submittal also addressed revenue allocations for SDG&E's customers, the ACR was also served on parties in the SDG&E dockets. The ACR sought additional clarifying information from DWR, allowed parties to comment on DWR's July 23 submission, and set a date for a technical workshop. DWR submitted the additional information to the Commission on July 26, 2001.

The Commission convened a technical workshop on July 27, during which parties had an opportunity to ask questions of DWR representatives concerning their July 23 revenue requirement submittal (including the July 26 clarifying information). To the extent that DWR was unable to provide immediate answers at the workshop, DWR provided a written response that was served on parties of record on August 1. On August 3, parties filed their written comments in response to DWR's July 23 revenue requirement submittal.

DWR submitted an additional update of its revenue requirement on August 7, incorporating updated or revised calculations and amounts relating to various elements underlying its forecasts. DWR also addressed the parties' August 3rd comments. On August 9, the ALJ issued a ruling to allow parties to comment on DWR's August 7 revised revenue requirement. In addition, DWR submitted a letter to Commissioner Lynch and ALJ Thomas Pulsifer responding to the issue of whether DWR has complied with the requirements of AB1X in making its determination of a just and reasonable basis for DWR's revenue requirement.

The Commission is very appreciative of the prompt and diligent response by parties to the DWR submissions and offerings. The urgent need to expedite our decisions for the bond issuances, as requested by DWR and the State Treasurer, has required us to streamline our processes, but we have done so within the limits of our authority. The processes we have followed to reach these decisions will not establish a precedent for our future actions.

V. Overview of the Revenue Requirement Submission of DWR

DWR's updated revenue requirement for all three utilities totals $12.6 billion, as shown in Table A-1 and Table A-3 of Appendix A, which is attached to this decision.[12] DWR clarifies that it seeks to collect $12.6 billion from electric retail customers, and $477 million from sales of DWR surplus contract energy. The revenue requirement of $12.6 billion covers the period from January 17, 2001 through December 31, 2002, and reflects an aggregate amount for all three electric utilities.

DWR prepared its revenue requirement forecast in cooperation with its consultant, Navigant Consulting. The financial model used by Navigant has been reviewed by Montague Derose & Associates (financial advisor to DWR), Public Resources Advisory Group (financial advisor to the State Treasurer's Office), and analysts of JPMorgan (investment bankers for the State Treasurer's Office). In addition, PriceWaterhouseCoopers is in the final stages of completing an independent audit of the mathematical accuracy of the financial model. These

[12] Except for Table A-8, the tables shown in Appendix A are excerpts from DWR's August 7, 2001 update to its revenue requirement.

reviews pertain principally to the financial results of the models. Navigant is responsible for the forecasts of net short energy requirements and the resources used to meet the forecasts that support the revenue requirements.

In its August 7 update, DWR provides the following support for its determination that its revenue requirements are just and reasonable, including:

- DWR used a competitive solicitation method for obtaining power supply bids.
- Power purchases by DWR are at cost and DWR is a governmental agency that receives neither equity return nor any form of economic return for its energy purchases.
- Projected spot market purchases not obtained via contract are estimated based upon a competitive, marginal cost, market clearing price projection.
- DWR's revenue requirement will be adjusted or trued-up over time to reflect only those costs which are actually incurred by DWR for power supply acquisition and administration.
- Actual and projected costs are below prior cost estimates submitted to the Commission in May 2001 and earlier market projections.

Water Code Section 80100, added by AB1X, provides the relevant considerations for DWR when it undertakes to purchase power, following its consultation with the Commission, utilities and public agency utilities:

(a) The intent of the program described in this division is to achieve an overall portfolio of contracts for energy resulting in reliable service at the lowest possible price per kilowatt hour.

(b) The need to have contract supplies to fit each aspect of the overall energy load profile.

(c) The desire to secure as much low-cost power as possible under contract.

(d) The duration and timing of contracts made available from sellers.

(e) The length of time sellers of electricity offer to sell such electricity.

(f) The desire to secure as much firm and nonfirm renewable energy as possible.

It is impossible for us to determine whether each element of Water Code Section 80100 has been appropriately considered by DWR. The Legislature has assigned to DWR, and not to the Commission, the responsibility to consider these factors and to conduct and determine reasonableness of costs under Section 451. This decision presumes that the considerations urged by DWR satisfy at least elements (a), (c), (d) and (e) of Section 80100. We can then proceed to the quantitative process of converting the power purchase program into a set of charges that when applied to volumes will produce revenues to pay for DWR AB1X-authorized costs.

VI. Elements of the DWR Revenue Requirement

DWR computes its revenue requirement in a two-step process. Step 1 involves the aggregate determination of DWR's gross expenditures. In Step 2, DWR applies a portion of its forecast bond proceeds to its gross expenditures and then determines the remaining amount that it needs to collect from utility customers and submits that amount to the Commission as its AB1X-authorized revenue requirement. The difference between total projected expenditures of $21.446 billion and the total revenue requirement of $12.5 billion results from DWR's determination of its estimate of bond proceeds which offset total expenditures. DWR's estimated revenue requirement is broken down on a quarterly basis by each of the six categories specified in Water Code Section 80134, together with certain additional detail: [13]

- Bond related costs, including principal and interest amounts
- Operating expenses, in which DWR has included power purchase, fuel, transmission, scheduling and demand side management
- Reserves
- Pooled money investment rate on general funds advanced
- Repayment of the General Fund
- Administrative costs

A. Bond-Related Costs

DWR's revenue requirement does not include any bond debt service costs until September 1, 2002. The bond financing provides for capitalized interest through mid-October 2002. Capitalized interest consists of bond interest payments that will be paid from the proceeds of the bonds rather than being charged to current utility customers. Beginning on September 1, 2002, DWR will set aside funds to enable it to make semiannual debt service payments. Amortization of bond principal is not scheduled to begin until May 1, 2004. Deposits for principal payments in the Debt Service Account, however, will begin on March 1, 2003. General Fund appropriations to DWR and interim loan balances are to be repaid from the bond proceeds.

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[13] DWR explained in Exhibit C of its August 7 update how its forecasted costs relate to the cost categories in the proposed Rate Agreement between DWR and the Commission, and why it believes they are consistent with Water Code Section 80134. Appendix B of this decision, which is derived from Exhibit C of DWR's August 7 update, sets forth a description of each cost category in the proposed Rate Agreement, with references to the costs reflected in Tables A-3 through A-6 of Appendix A of this decision.

B. Operating Expenses

The operating expenses contained in DWR's revenue requirement include payments for power purchases, fuel, transmission, scheduling, and demand side management. These expense elements are summarized in Appendix A in Tables A-3 through A-6. DWR's projections of total operating expenses through December 2002 for the three utilities' service territories include $9.706 billion for contract power, $9.437 billion for residual net short purchases,[14] and $1.057 billion for ancillary services. Fuel costs are included in the total energy costs through the use of a generation dispatch model based on quantity and price of energy. The natural gas prices assumed in DWR's analysis are shown in Table A-7. DWR has also included in its operating expenses certain demand side management (load-reduction) costs that are being excluded from the revenue requirement with one important exception, as explained further in Section VIII.

C. Reserves

Bond proceeds are used to fund a debt service reserve fund (DSRF). The DSRF represents 50% of maximum annual debt service. The projected $707 million DSRF is funded with cash (rather than surety bonds). An additional reserve fund, a rolling debt service coverage fund, of an estimated $495 million, is also funded with bond proceeds. The DSRF and rolling coverage reserve funds are in addition to the Electric Power Fund balance noted in Table A-1. As a result, DWR's revenue requirement reflects the amounts DWR estimates to be necessary to meet its obligations while at the same time holding as cash over

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[14] "Residual net short purchases" include all net short purchases other than ancillary services, in addition to DWR power purchases under bilateral contracts.

$1.2 billion in reserves. The Electric Power Fund also is projected to contain between $1.1 billion and $2.1 billion which serves as a cushion or an operating reserve against certain risks and contingencies. DWR represents that these reserves are necessary and appropriate to obtain the required investment grade on the bonds.

D. Pooled Money Investment Rate on General Funds Advanced

Table A-1 includes the total quarterly financing costs. These costs include an interest charge per annum on General Fund advances that have been made to pay for net short energy costs. Interest on General Fund monies advanced to the Electric Power Fund will be charged at the quarterly average pooled money investment rate based on the average loan balance during each quarter. The average pooled money investment rate for the first quarter of 2001 was 6.175% and the average rate for the second quarter was 5.329%.

E. Administrative Costs

DWR's Administrative & General (A&G) expenses estimated on an annual basis are found in column B of Tables A-3 through A-6. The A&G breakdown for 2001 costs provided by DWR includes the following:

	($000s)
Labor Including Benefits	$11,513
Capital Expenditures	$ 2,919
Professional Service Fees	$ 9,905
Other A&G	$ 1,246
Total	$24,772

We will include in today's development of DWR-related charges the administrative and general expenses estimated by DWR. In order to ensure that we do not pass on to customers administrative costs that are not actually incurred or that are not approved by the legislature as part of DWR's budget, we will direct DWR to include in its February 1, 2002 submission to the Commission the actual administrative and general expenses incurred during 2001, and we will recognize any difference in charges going forward.

F. DWR's August 7th Update of the Revenue Requirement

DWR incorporated the following adjustments in its August 7th revenue requirement update:

- Minor modifications to load assumptions;
- Modifications to quantities of bilateral contracts held by PG&E and SDG&E that will impact the amount of net short expected to be purchased by DWR;
- Modifications to the level of Qualifying Facility (QF) contract output for SDG&E;
- Modification of total estimated quantity and associated costs of QF output for Edison, which in turn will affect the allowance for costs of ancillary services (since ancillary services are estimated as a percentage of net short purchases and the costs of utility retained generation);
- Revised data on historical net short cost reconciliations; and
- Cash receipt reconciliations.

DWR reports that the cumulative result of these modifications has been to lower the share of the net short energy requirements for SDG&E customers and, to an extent, for Edison customers, and to increase the net short energy requirements for PG&E customers. According to DWR, these changes will result in projected DWR sales of 116,084 GWhs, as compared with 118,920 GWhs in the July 23 submittal, a reduction of 2,836 GWhs. DWR's projected net short for PG&E is now 55,417 GWhs, compared to 48,078 GWhs. DWR's projected net short for Edison is now 42,307 GWhs, compared to 49,083 GWhs. DWR's projected net short for SDG&E is now 18,631 GWhs, compared to 21,769 GWhs.

The change in net short energy provided for the customers of the respective utilities reflects a more precise assignment of DWR purchases in the major ISO zones, NP 15 (roughly the area served by PG&E, which is North of Path 15) and SP 15 (roughly the area served by SCE and SDG&E, which is South of Path 15). DWR bases this projection on its new net short energy cost projection changes, and applies a "postage stamp "allocation of the costs to the customers of all three utilities. A postage stamp allocation spreads costs on a uniform cost per kWh basis to all customers.

VII. Discussion of Process and Definitional Issues Concerning DWR's Revenue Requirement Forecasts

PG&E, Edison, The Utility Reform Network (TURN), the Office of Ratepayer Advocates (ORA), Aglet Consumer Alliance (Aglet), the Federal Executive Agencies (FEA), and—jointly--the California Large Energy Consumers Association (CLECA) and the California Manufacturers and Technology Association (CMTA) filed comments on August 3, 2001 in response to the July 23 DWR revenue requirement submittal, including DWR's August 1 update.

PG&E, Edison, TURN, Aglet, FEA, SDG&E, the City of San Diego, CLECA/CMTA, and DWR submitted supplemental comments to the August 7 DWR update, and to the questions raised in the August 9 ruling.

The non-DWR parties generally claim that DWR has not provided adequate documentation and explanation of its revenue requirement. Parties assert that they have not been permitted a thorough review and analysis of the methodology and assumptions underlying the revenue requirement, and that further proceedings are needed to establish a reasonable estimate of the revenue requirement. Appendix D of this decision sets forth the various comments of the parties on some of the key variables that are contained in DWR's revenue requirement forecast. We address below process issues relating to the parties' claims concerning the revenue requirement.

DWR states that its revenue requirement is based on reasonable forecasts and proposes to work with PG&E and Edison to seek a balance between self-provisioning of ancillary services and their respective net short energy and ancillary service costs. DWR agrees that such cost tradeoffs would be reflected in future adjustments of its revenue requirement. Similarly, DWR agrees that any necessary revisions to its natural gas price forecasts that result in a lower revenue requirement will be incorporated prospectively.

We affirm the prior ruling of the ALJ dated July 12, denying PG&E's and Edison's motions to include the DWR revenue requirement issues in the evidentiary hearings on URG issues for PG&E and Edison. In order to implement the revenue requirement for DWR on a timely basis, consistent with the schedule for the sale of long term bonds later this fall, we cannot defer the DWR revenue requirement issues to permit consolidation with the URG evidentiary hearings. Nor do we believe we are required to do so. We believe that there is a sufficient record to implement the actions we take today.

Moreover, the procedural process for the compilation, review, and implementation of the DWR revenue requirement must conform to the governing requirements of the California Water Code pursuant to AB1X. Water Code Section 80110 provides that DWR "shall be entitled to recover, as a revenue requirement, amounts and at the times necessary to enable it comply with Section 80134, and shall advise the commission as the [DWR] determines to be appropriate." The procedural process we have employed has provided an opportunity for parties to review and comment upon the DWR revenue requirement. This procedural process has been intended to facilitate DWR's receiving its revenue requirement "at the time[] necessary."

We do not address parties' contentions regarding the manner in which DWR fulfills the procedural and substantive obligation to "conduct" any reasonableness review under Section 451, and to make a determination that its revenue requirement is reasonable. The decision about what process DWR must follow in conducting and determining "any just and reasonable review under Section 451" is not one the Commission should be making, especially as it is a topic of ongoing litigation. The determination of whether DWR's power procurement costs are just and reasonable has been expressly committed to DWR. We have noted that the forecasts of certain costs included in DWR's revenue requirement submission are projections of costs which may or may not be incurred. However, as provision is made for subsequent adjustments of the DWR revenue requirements in periodic updates, variances between forecast and actual results can be taken into account in the process of revising DWR charges going forward. An overcollection in one year will reduce the next year's revenue requirement and the charges needed to recover it. We intend to continue to cooperate with DWR to facilitate the process of accurately identifying relevant costs and implementing necessary recovery measures as mandated by statute.

VIII. DWR Should Recover in its Revenue Requirement Those Costs Authorized by AB1X

AB1X provides that DWR is entitled to recover as a revenue requirement the amounts enumerated in Water Code Section 80134. The Commission's authority under Public Utilities Code Section 451 is made applicable to AB1X costs, except that "any just and reasonable review…shall be conducted and determined by " DWR. As a result, it is proper for us to implement this revenue requirement, provided it is mathematically correct and reflects only those categories of costs that are authorized in AB1X. We accept DWR's assurance that the mathematical calculations underlying the DWR revenue requirement are correct, and that the reported costs reflect only those categories authorized by AB1X, with one exception. We find that the costs for load reduction that DWR has included in the revenue requirement are not covered under any of the permissible categories set forth in the statute. Therefore, in general we shall exclude these costs as reflected in DWR's submission in implementing the DWR revenue requirement.

AB1X requires that DWR include in its revenue requirement "…amounts necessary to pay for power purchased by it…" (Water Code Section 80134(a)(2).) Amounts in the Electric Power Fund are to be spent on the "…cost of electric power…." (Water Code Section 80200(b)(2).) The term "power" is specifically defined as "electric power and energy, including but not limited to, capacity and output or any of them." (Water Code Section 80010(f).) This definition does not include other expenditures unrelated to electric power supply, including costs for load reduction.

We shall, however, retain in the DWR revenue requirements the DSM costs representing the "California 20/20 Rebate Program" for this year. This particular program has already been authorized by the Commission as a utility-tariffed program. Pursuant to Resolution E-3733, dated May 3, 2001, the Commission ordered the three utilities to file tariffs that implement Executive Orders issued by Governor Gray Davis for a one year rate reward rebate program.[15] As explained in that resolution, Governor Davis has issued Executive

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[15] The rebate reward program provides up to a 20% credit to those customers who reduce their energy usage by at least 20% during the June-to-September 2001 billing

Footnote continued on next page

Orders charging DWR with responsibility for implementing this program. The term of the Executive Orders is due to expire on December 31, 2001. Therefore, we shall include costs of the 20/20 Program in the DWR revenue requirement through December 31, 2001 for the actual period that the program is in effect. We shall not include 20/20 Program costs beyond the limited term during 2001 that the tariffs and Executive Orders are in effect.

IX. Implementing Annual Revenue Requirements and Future Adjustments

PG&E and Edison have asked the Commission to require DWR to set up balancing accounts to true-up the difference between its total estimated and actual expenditures on a retroactive basis. Aglet has referred to the possible need for more frequent modifications of the revenue requirement without specific reference to true-ups or balancing accounts. TURN has indicated concern about overcollections resulting from DWR's revenue requirement.

Because DWR is responsible for communicating to the Commission its revenue requirement and any subsequent adjustments, we expect DWR to take responsibility for identifying necessary periodic adjustments in its revenue requirement over time to reflect variances between actual and forecasted costs and to take into account actual and projected fund balances when determining its revenue requirements.

As discussed in the technical workshop and in DWR's August 1 response, DWR contemplates updates to the revenue requirement at least annually as required by AB1X. Therefore, at least one reevaluation of the revenue

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periods for PG&E and Edison. SDG&E customers must reduce their consumption by at least 15% during the same period to qualify for a rebate.

requirement will occur in calendar year 2002. If there are significant prolonged variances in the actual revenue requirement, DWR states that it is likely that a more frequent adjustment or exception to the annual adjustment would be made.

DWR states that, over time, the actual revenues that it collects will indeed track the actual net short energy requirements of the customers of each utility service area as well as the amount of self-provision of ancillary services. As discussed at the workshop, DWR will track its net short energy purchases and ancillary service purchases to compare against the projected accruals of the revenue requirement and will update projections on a monthly basis. DWR will use this monthly monitoring to determine if there should be any adjustment, up or down, in the revenue requirement and the associated recovery of that revenue requirement from the customers of the respective utilities. To the extent that any material differences arise, either positively or negatively, DWR will submit an adjusted revenue requirement to the Commission.

We encourage DWR to work with the Commission and its staff to closely monitor this tracking process. We acknowledge parties' concerns that the revenue requirement may be based on forecasts that may prove to be incorrect. The process for adjusting the revenue requirement is described in Section XII of this decision.

X. Allocation of Aggregate DWR Revenue Requirement Among the Utility Service Areas

A. DWR Proposal

DWR separately allocated a portion of the total requirement to each of the three utility service territories. The changes between DWR's July 23rd version and August 7th version are set forth below, in GWh and in thousands of dollars:

- **Net short volumes (*in GWh*)**

Utility	Revised Net Short (Aug. 7, 2001)	Previous Net Short (July 3, 2001)	Difference	Percent Change
Edison	42,037	49,083	(7,046)	(14.36%)
PG&E	55,417	48,078	7,338	15.26%
SDG&E	18,631	21,769	(3,138)	(14.42%)

- **DWR Revenue Requirement by Utility (*in thousands of dollars*)**

Utility	**Aug. 7, 2001 Version**		**July 23, 2001 Version**		**Difference**	
	2001	2002	2001	2002	2001	2002
Edison	2,087.451	2,516,710	2,171,703	3,631,572	(84,252)	(1,114,862)
PG&E	3,361,933	2,565,851	2,131,312	3,066.374	1,230.621	(500,523)
SDG&E	836,865	1,231,576	827,315	1,243,652	(9,550)	(12,076)
Totals	6,286,249	6,314.137	5,130.330	7,941,598	1,136,819	(1,627,461)

At the workshop, DWR acknowledged that allocation was the Commission's responsibility, and proposed an allocation to facilitate the process. DWR representatives explained the methodology that was used to allocate its revenue requirement among the three utilities. DWR first aggregated its revenue requirement for covering the net short position for all three utilities for the forecast period, and then divided by the total mWh volumes associated with that revenue requirement. DWR thereby derived a uniform cents per mWh cost for DWR-supplied energy. A pro-rata share of the total revenue requirement was then assigned to each of the three utilities by multiplying the derived cost per mWh of DWR-supplied energy by the estimated volumes representing the net short position for each utility.

DWR's inter-utility revenue allocation results in a significant difference on a per-kWh basis. Based on its July 23 filing, the allocations were $108/mWh for PG&E, $118/mWh for Edison, and $95/mWh for SDG&E. As DWR explained in its August 1 data response, the differences in allocation result from applying a disproportionate share of bond proceeds as an offset to costs for SDG&E in comparison to the other utilities.[16] DWR's intent was to allocate bond

[16] By allocating a disproportionate share of bond proceeds in this manner, DWR is inconsistent with a cost-of-service allocation approach.

proceeds among the service territories of the three utilities so that DWR's current revenue requirement could be collected from customers within the currently approved rate structures (and the rate structure DWR assumed would be approved for SDG&E). DWR claims that its revenue requirement for the customers of all three utilities can be accommodated within the three cent per kWh rate surcharge applied by the Commission to customers of Edison and PG&E. DWR also projects that its revenue allocation would result in no more than a 2.99 cents per kWh increase for SDG&E customers.[17]

B. The Parties' Positions

By allocating a relatively greater share of bond proceeds to SDG&E as compared with the other two utilities, current rate levels for SDG&E customers are correspondingly lower than they would otherwise be. Conversely, by applying more bond proceeds to reduce certain customers' current rate levels, those customer groups would assume responsibility for the repayment of higher debt levels in future years, leading to a correspondingly higher rate level for those customer groups relating to the higher future debt service obligations.

Edison disagrees with the revenue allocation employed by DWR on the basis that it is arbitrary and fails to recognize differences in costs among the three utilities. Edison argues that the DWR revenue requirement should be allocated among the utilities and their customers based on the actual cost of providing service for each of them. Edison suggests that the Commission undertake a

[17] We note that the reference to this DWR projection does not constitute a prejudgment of the any ratemaking or revenue allocation issue pending before the Commission in A.00-10-045, et al.

two-step approach in a comprehensive cost allocation proceeding. In the first step, the Commission would allocate the total DWR revenue requirement among the customers of the three utilities, based on cost of service. The second step proposed by Edison is to allocate that revenue requirement and the utility's own URG revenue requirement to the customer classes of that IOU.

PG&E contends that DWR allocates $750 million more in bond proceeds to PG&E than would be indicated if the bond proceeds were allocated proportionally to the forecast net short amount yielding the same rate for each utility's customers. Although DWR's motive (lower rates in the near term, in return for higher bond repayment costs in the longer term) may be expedient, PG&E argues that this approach does not constitute sound ratemaking. Over the long run under DWR's proposal, PG&E's customers would bear a higher burden of debt service costs for the DWR bonds than would be justified by DWR sales.

DWR argues that its uniform statewide cost allocation approach reduces the potential bond rating agency and investor concerns regarding the diversification of credit risk, and ultimately, regarding customers' ability to pay the higher charges. DWR states that the bonds' financing structure is predicated on power purchases on a statewide system.

DWR contends that allocating its revenue requirement based on actual costs per utility service area could create cost disparities based on the volume of contract power the state has secured for delivery to points in each service area. If a uniform statewide allocation of revenue requirement is not used, DWR states that arbitrary decisions regarding the allocation of power could result, with negative economic consequences for customers. In addition, DWR contends that because power purchased under many contracts will be used to meet net short in more than one service area, any inter-utility allocation of costs between contracts could be viewed as arbitrary. DWR maintains that allocating a disproportionate share of spot market costs to one region could lead to greater cost volatility for that region, and undercut the goal of statewide price stability.

FEA contends that DWR has not provided adequate data regarding the allocation, but acknowledges the need for an interim allocation of DWR's revenue requirement among the three utility service territories because of the time constraints and the need for DWR to have some certainty in order to effectuate the necessary bond financing. Accordingly, FEA supports an interim allocation that would permit the financing to go forward, and that would be subsequently adjusted in a future phase in the instant docket.

C. Discussion

The allocation of revenue requirements based upon cost of service provides for an equitable and economically efficient matching of cost responsibility with service rendered. The allocation methodology applied by DWR is not based on the traditional cost-of-service approach that has long been the standard applied by this Commission in allocating costs to be recovered from utility customers. DWR's approach, by contrast, disregards the different geographic regions and customer groups served, and allocates a uniform or "postage-stamp" charge to the customers of each of the utilities. The DWR allocation approach is specifically designed to achieve objectives DWR feels are important.

"The primary purpose of the Public Utilities Act . . . is to insure the public adequate service at reasonable rates without discrimination." United States Steel Corp. v. Public Utilities Com., 29 Cal. 3d 603, 610 (1981), quoting Pacific. Tel. & Tel. v. Public Utilities Com. 34 Cal.2d 822, 826 (1950). Although the Commission may justify variances from cost of service in allocating rate responsibility among customers, there must be an adequate rationale for doing so. California Manufacturers Ass'n v. Pub. Utilities Com., 24 Cal.3d 251, 261 (1979). DWR's asserted justifications for departing from traditional cost-based allocation of revenue responsibility – the detrimental consequences of arbitrary or mistaken allocations of spot market purchases or contracted-for power – are uniquely within the power of DWR to avoid. Conversely, the arguments by the other parties, particularly the utilities, articulate a strong rational basis for retaining a cost-based approach for allocating revenue responsibility to the customers of the respective utilities. Toward Utility Rate Normalization v. Public Utilities Com., 22 Cal.3d 529, 543-544 (1978).

Consistent with traditional utility ratemaking practice, we therefore adopt an allocation of the DWR revenue requirement that is based on the cost of service for each of the utilities' service territories. We will separately allocate energy procurement on a geographic basis, depending on whether the energy is delivered over facilities in northern California or in southern California. As the geographical dividing point, we shall use what is commonly known as Transmission Path 15. Energy sources procured north of Path 15 shall be allocated to PG&E customers. Energy sources procured south of Path 15 shall be allocated to customers of Edison and SDG&E.

DWR has provided summary information that allowed the Commission's Energy Division to calculate the amount of energy costs that were allocated to each utility service area before the DWR combined these costs for its "postage stamp" calculations. These energy costs consist of contract power, residual net short purchases, and ancillary services, and are based on DWR's estimates of the contract volumes and residual net short volumes in each utility service area. The table below shows these original cost allocations, along with the "postage stamp" allocations from Tables A-4 through A-6 of DWR's August 7 submittal.

Original DWR Cost-Based Allocation ($000)

	Contract Power	Residual Net Short	Ancillary Services	Total Power Costs
PG&E	$5,176,168	5,183,811	450,689	10,810,668
SCE	3,249,520	3,078,861	465,105	6,793,486
SDG&E	1,279,933	1,174,809	141,065	2,595,807
	$9,705,622	9,437,481	1,056,859	20,199,962

DWR "Postage Stamp" Allocation ($000) **Difference**

	Contract Power	Residual Net Short	Ancillary Services	Total Power Costs	Difference
PG&E	$4,766,813	5,127,008	445,672	10,339,493	-471,175
SCE	3,418,778	3,098,794	414,816	6,932,388	138,902
SDG&E	1,520,031	1,211,679	196,371	2,928,080	332,273
	$9,705,622	9,437,481	1,056,859	20,199,962	

The table shows that DWR's postage stamp allocation has lowered the amount of total power costs allocated to PG&E by $471 million, and shifted that revenue responsibility to Edison ($138 million) and SDG&E ($332 million).

To the "cost-based" power costs shown in the above table, we add the other DWR revenue requirement components (*e.g.*, administrative and general expenses, uncollectibles, 2001 "20/20" program costs, and financing costs), to produce the total of all costs DWR expects to incur over the period of January 17, 2001 through December 31, 2002: $22.467 billion. Subtraction of $10.38 billion in net bond proceeds yields the amount that must be collected from ratepayers: $12.086 billion. (App. A, Table A-8.)

The Commission uses the same "cost-based" allocator to allocate the bond proceeds between the three utilities. Thus, since PG&E, Edison, and SDG&E are allocated 54%, 33% and 13% of total DWR costs, each utility is assigned the same percentage of bond proceeds.

As a result of the cost-based allocation approach we use, the following allocation of DWR revenue requirements among the three utilities shall apply. The revenue requirement allocations for the period January 17, 2001 through December 31, 2002 are $6,532,650,000 for PG&E, $4,017,786,000 for Edison, and $1,536,351,000 for SDG&E. (See App. A, Table A-8.) We shall address any rate implications for PG&E and Edison as a result of today's decision in conjunction with our subsequent order in the URG phase of this docket. We address the need for any change in rates for SDG&E customers in order to meet DWR's costs of serving SDG&E customers in a separate decision that is being issued today.

Accordingly, we will use the cost-based allocation described above in setting the DWR charges that we order today. However, we agree with the parties that it may be desirable to have hearings on the issues involved in allocating DWR costs among service territories. On the other hand, we need to adopt DWR charges now, in order to facilitate timely recovery of DWR's costs. Further, as suggested in one of the comments, adopting an allocation among the utility service territories now, but one that would be subsequently reviewed for possible adjustments, would give certainty in effectuating the necessary bond financing. Accordingly, we will implement the cost-allocation described above in today's order and also schedule hearings[18] to consider possible prospective

[18] Because the precise issues that need to be addressed have not yet been delineated, it is possible that notice and comment procedures, rather than evidentiary hearings, will be sufficient to address the issues. We will make this determination once the issues to be considered are determined.

revisions to this cost allocation. But even any revisions to this cost allocation will still necessarily be based on estimates, which may vary greatly from the actual costs incurred.

Our goal is that, over time, the customers in each service territory will pay for the cost of DWR service in that territory. In order to achieve this goal, we will set up a process whereby the actual costs incurred in each service territory will be compared with the costs previously projected. Then, we will set prospective DWR charges for each service territory so that, over time, the DWR charges paid in each service territory will approximate the actual costs incurred in providing DWR service to that territory. We will not retroactively adjust any past DWR charges, nor establish any formal accounts to achieve this result, but instead will simply take account of past variances between actual and projected costs in each service territory in setting future DWR charges. We intend to conduct this process as part of our annual processing of DWR's revenue requirement.

XI. Establishment of a Separate Charge for DWR Electric Power

The Commission's responsibility is to set the overall rate that electric customers see on their bills. However, parties generally agree that breaking this charge down to reflect a separate amount per kWh sold by DWR will make the rate structure more efficient. Edison and PG&E maintain that breaking out a DWR charge will eliminate the need for them to maintain their own balancing accounts for DWR payments and revenues. Instead, the actual amount of revenue that is generated by reference to the DWR charge and the amount of kWh sold by DWR will be remitted directly to DWR.

We agree that it is reasonable to reflect an amount per-kWh that is attributable to sales by DWR.[19] Although the effect may be muted by the use of bond proceeds to pay for procurement costs, establishing a per kWh charge for DWR will cause its revenues to vary in some proportion to the amount of energy it is procuring. This approach facilitates the independent calculation of charges that will be segregated and remitted directly to DWR. The forecasted net short position in GWh and the revenue requirement to be allocated to each utility provide the basis for the calculation of a system-wide amount per-kWh sold for electricity sold by DWR to the customers of each utility.

As noted previously, however, we are adopting a cost-of service basis to allocate the DWR revenue requirement among the utilities' service territories. Accordingly, for each utility's service territory we calculate a DWR charge of: 13.99 cents per kWh for PG&E, 10.03 cents per kWh for Edison and 9.02 cents per kWh for SDG&E.[20] We shall therefore direct each of the utilities to begin

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[19] While we establish a separate per-kWh charge for DWR, we do not require the utilities to show this charge as a separate line item on customers' bills. We discuss this in our separate orders adopting Servicing Agreements between DWR and Edison, SDG&E, and PG&E, respectively.

[20] These rates were calculated for PG&E and Edison by taking the allocated revenue requirement, and subtracting the generation revenues that each utility should have collected and disbursed to DWR from January through May of 2001, to obtain the revenue requirement from June 2001 through December 2002. That revenue requirement is then divided by DWR's forecast sales for the same period, to obtain the specific rate that each utility must use to calculate its payments to DWR, from June 1, 2001 onward.

For SDG&E, the same calculation was performed by taking the allocated revenue requirement, and subtracting the generation revenues that SDG&E should have collected and disbursed to DWR from January until September 15, 2001, to obtain the revenue requirement from September 15, 2001 through December 2002. That revenue requirement is then divided by DWR's forecast sales for the same period, to obtain the

Footnote continued on next page

disbursing payment to DWR for its revenue requirement based on the relevant DWR charge for each kWh sold by DWR to the utility's customers. Utilities shall begin calculating and distributing payments on this basis as applied to kWhs billed on and after September 15, 2001.

For PG&E a separate calculation will be needed to determine whether the rate above may result in PG&E having to remit additional funds to DWR, beyond the amounts already remitted for DWR power delivered since June 1st. PG&E and Edison should already be collecting and remitting to DWR an amount determined by multiplying the sum of their utility-specific generation rate and the energy surcharge rates approved by the Commission in D.01-05-064 by the volume of power delivered to their customers on behalf of DWR since June 1st. The utility-specific DWR charges we calculated above indicate that PG&E may need to remit to DWR an amount above the funds they have remitted since the energy surcharges took effect on June 1st. For PG&E, that amount is 4.0 cents per kWh on each kWh that was provided to PG&E customers by DWR beginning on June 1st (13.99 minus the 6.47 cents per kWh generation rate, minus PG&E's average energy surcharge of 3.52 cents per kWh). For Edison, there is no need to remit additional payment to DWR for the period between June 1 and September 15, because the sum of Edison's generation rate and the average energy surcharge is greater than 10.03 cents. For SDG&E, the DWR charge will be applied only to kWh sales billed beginning on September 15, 2001, so there is

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specific rate that SDG&E must use to calculate its payments to DWR, from September 15, 2001 onward.

The calculations are illustrated in Appendix A, Table A-8.

no need to calculate any additional payment for DWR purchases prior to that date.

DWR will receive from each utility the revenues that the utility collects on behalf of DWR, based on the fixed DWR charge per kWh as noted above. The per-kWh charge payable to DWR shall remain fixed, even though the actual percentages of system sales supplied by DWR will vary each month. However, we do not want the retail rate applied on each utility customer's bill to fluctuate from month-to-month merely due to changes in the percentage of sales supplied by DWR each month. Such monthly fluctuations on customer bills would cause undue customer confusion.

With fixed retail tariffed rates and a fixed per kWh charge payable to DWR, there is, in effect, an amount that the utility is entitled to receive for its own account for the kWhs that it supplies to its retail customers. We will call this amount the "imputed utility rate." To the extent that the actual percentage of DWR sales to each utility's retail customers is either less than or exceeds the forecast percentage of DWR sales to those customers for any month, the customers' bills for that month will not reflect exactly the imputed utility rate for the kWhs the utility provides. However, it is not our intent that the utility ultimately recover either more or less than the imputed utility rate for the kWhs it provides. Therefore, in order to ensure that the utility recovers neither more nor less than its imputed rate, we shall authorize and direct the utilities to establish a balancing account mechanism.

As noted above, although the end user's retail rates will not fluctuate to reflect monthly differences in DWR sales, the rate per kWh that is included in the bill for the power that the utility provides (i.e., the "effective utility rate") will vary from month to month. By truing up this balancing account at a later date, we will ensure that the utility bills, and its customers pay, (over time) the imputed rate[21] for utility-supplied power consistent with the revenue requirements implemented in today's decision.

XII. DWR Revenue Requirement Implications for Utility Rate Needs and Plan for Update of DWR Revenue Requirement

In today's decision, we make no changes in the existing rate levels charged to end-use customers of the three utilities. Any rate changes for SDG&E will be addressed in a separate order in A.00-10-045 et al. In this decision, we simply order the three electric utilities to remit to DWR its revenue requirement as provided to us, as modified herein, and as collected from end-use retail customers in those utilities' service territories through application of the charges we approve today. As previously discussed, any rate adjustments for PG&E or Edison will be addressed in conjunction with the URG phase in the instant dockets. Any payment remitted to DWR will be done in accordance with the terms of the Rate Agreement and Servicing Agreements that we adopt today in separate orders.

We recognize that the utilities still incur ongoing expenses for their own URG, that is, the generation that remains under the control of the utilities. Proceedings are currently underway in a separate phase of these dockets to adopt revenue requirements for the URG-related costs for PG&E and Edison, respectively. Pending our subsequent adoption of URG revenue requirements, we cannot be certain whether revenues now being collected by PG&E and Edison

[21] We expect that through the URG proceedings for the utilities that the "imputed"utility rate will be replaced with an actual utility rate.

through existing rates will be sufficient both to fund the DWR requirement and the URG requirements. We will not prejudge the subsequent outcome of the URG phase of these proceedings. Based upon the estimates of URG revenue requirements that have been submitted as testimony in that phase by PG&E and Edison, however, we note that there is a range of potential outcomes that could be decided by the Commission. Depending on the amount within that range the Commission ultimately adopts, there could be either a shortfall or surplus of revenues for PG&E or Edison, respectively. We will address these possibilities, as necessary, in future proceedings.

Through the use of its bond proceeds to manage the amount of revenue requirement due from current customers, DWR forecasts that it should be possible to avoid additional bond issuances through at least the year 2004. In any event, we acknowledge the need to promptly consider and act upon any financial consequences that may result from our order today.

As prescribed in AB1X (Water Code Section 80134(a)), DWR will revise its retail revenue requirement at least annually, and more frequently as deemed reasonably necessary or appropriate by the DWR review described in the Rate Agreement that we adopt in a companion decision. Consistent with the statute and the Rate Agreement, we intend to adopt a procedural plan for DWR to submit to the Commission updated forecasts of its retail revenue requirement on at least an annual basis.

We hereby adopt a procedural plan calling for the next update of the DWR revenue requirement to be submitted to the Commission on February 1, 2002, with revised DWR charges to take effect on June 1, 2002. Accordingly, the revenues provided to DWR from the charges that we implement in today's order (together with revenues that DWR has already collected from the utilities to date)[22] will provide recovery of DWR's revenue requirements from January 17, 2001 through May 31, 2002.

We recognize that DWR's revenue requirement submission covers a forecast period extending beyond May 31, 2002, and continuing through December 31, 2002. Our adopted procedural plan, however, will address the recovery of the revenue requirement for the period subsequent to May 31, 2002 in the subsequent DWR update process to be initiated in February 2002. At that time, DWR will submit a revised annual revenue requirement forecast covering the period June 1, 2002 through May 31, 2003. The updated DWR charges that we subsequently implement to take effect on June 1, 2002 will therefore provide recovery of DWR's revenue requirement for that subsequent 12-month period of June 1, 2002 through May 31, 2003.

By revising the DWR charges on June 1, 2002, rather than waiting for January 1, 2003, we shall provide for more timely updating of DWR's revenue requirements and will minimize any variances over time between revenues collected and actual requirements. A process of annual revisions in the DWR revenue requirements also comports with statutory directives. We shall direct the ALJ to issue a further ruling, as necessary, setting forth the manner and process whereby the DWR update shall proceed.

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[22] As explained previously in Footnote 20, the DWR charges implemented in this order provide for the collection of its revenue requirement, taking into account the revenues that each utility should have already billed, collected, and disbursed to DWR to cover the period from January through May of 2001 and an additional period for SDG&E.

XIII. Comments

The draft decision of ALJ Pulsifer in this matter was mailed to parties in accordance with Public Utilities Code § 311(g)(1) and Rule 77.7 of the Commission's Rules of Practice and Procedure. Rule 77.7(f)(9) requires that the Commission engage in a weighing of interests in determining whether or not we may waive the 30-day comment period. We have done so, and conclude that the public interest in resolving California's current energy problems and in timely issuing the bonds to support DWR's power purchases, clearly outweighs the public interest in having the full 30-day period for review and comment. Accordingly, we shall shorten the allowed period for comments on this draft decision. Comments shall be due on September 11, 2001.

Findings of Fact

1. AB1X, among other things, authorized DWR to purchase power and sell it to retail customers of PG&E, Edison, and SDG&E.
2. AB1X authorized DWR to determine its revenue requirement sufficient to recover its costs, and required the Commission to implement the recovery of DWR's revenue requirement.
3. DWR submitted its estimated revenue requirement on May 2, 2001, covering the 18 months from January 2001.
4. DWR provided the Commission with an updated revenue requirement on July 23, 2001, covering 24 months ending December 2002, and further updated its revenue requirement on August 7, 2001.
5. Parties of record were provided notice and an opportunity to review DWR's revenue requirement submittal of July 23, 2001 and its August 7, 2001 update, participate in a technical workshop, and to file comments in response to DWR's submittals.

6. Parties expressed disagreement with various forecast assumptions underlying DWR's revenue requirement, including ancillary services included in the net short requirements, gas prices, and franchise fees.

7. DWR's revenue requirement for each utility is derived first by forecasting aggregate revenue requirements for all three utilities, and then separately applying a percentage allocation factor to determine the amount assigned to each utility.

8. In D.01-03-082, the Commission granted a surcharge increase of three-cents per kWh to be collected by Edison and PG&E, prescribing that a portion of that surcharge would be allocated to DWR upon receipt, analysis, and comment on DWR's revenue requirement.

9. DWR forecasts a total revenue requirement of $12.6 billion, as set forth on Table A-1 of Appendix A of this decision, to be collected from customers of the three utilities over the period January 2001 through December 2002.

10. DWR states that it has determined that its revenue requirement is just and reasonable based upon several factors including its competitive solicitation of bids, cost-based recovery, and the true-up provisions of forecast variances that will take place in future adjustments.

11. Tables A-3 through A-6 of Appendix A of this decision set forth the details of the cost elements making up DWR's proposed revenue requirement in total and by utility.

12. Table A-7 of Appendix A summarizes the gas price forecasts underlying the DWR revenue requirement.

13. DWR's revenue requirement is based on forecasts of certain costs that may prove to be incorrect.

14. The mathematical calculations underlying the DWR revenue requirement are correct, and the reported costs reflect only those categories covered under AB1X, with the exception of certain DSM costs.

15. DWR's proposed allocation of the revenue requirement results in an allocation for PG&E's service territory in the amount of $ 5,927,784,000; for Edison's service territory in the amount of $4,604,161,000; and for SDG&E's service territory in the amount of $2,068,441,000 as set forth on Table A-2 of Appendix A of this decision.

16. By allocating a disproportionately larger share of bond proceeds to SDG&E's service territory relative to that of the other two utilities, DWR's proposed allocation method is intended to limit rate increase impacts to no more than 2.99 cents per kWh for SDG&E retail customers (as presently pending in A. 00-10-045 et al). However, such an allocation of bond proceeds would be inconsistent with a cost-of-service allocation approach.

17. If DWR's "postage stamp" allocation were used, the application of DWR's forecast assumptions would result in a charge of 11.38 cents per kWh for customers in the service territories of PG&E, Edison, and SDG&E on a going forward basis for each kWh sold by DWR.

18. DWR's allocation approach disregards the different geographic regions served, and allocates a uniform or "postage-stamp" charge to each of the utilities.

19. The allocation methodology applied by DWR is not based on the traditional cost-of-service approach that has long been the standard applied by this Commission in allocating costs to be recovered from utility customers.

20. The allocation of revenue requirements based upon cost of service provides for an equitable and economically efficient matching of cost responsibility with service rendered.

21. The cost-of-service allocation applied in Table A-8 of Appendix A is based upon allocation of energy sources procured on a geographic basis, with energy sources transmitted over facilities (a) north of Path 15 being allocated to PG&E, and (b) south of Path 15 being allocated to Edison and SDG&E.

22. The cost-of-service allocation applied in Table A-8 of Appendix A allocates the bond proceeds among the service territories of the three utilities in direct proportion to the costs allocated to each service territory.

23. The Commission has previously authorized the utilities to file tariffs to implement the California 20/20 Rebate Program on a limited term basis for 2001.

24. Pursuant to Executive Orders issued by the Governor, DWR has been given responsibility and has been authorized to implement the 20/20 Rebate Program.

25. Although the 20/20 Rebate Program are DSM-related costs that are not covered under the categories specified in AB1X, it is reasonable to include the 20/20 Rebate Program in the DWR revenue requirement, but only for the limited term during 2001 that the program has been authorized pursuant to the Executive Orders of Governor Davis.

26. The DWR revenue requirement is reduced to $12,086,786,000 after adjusting for the exclusion of DSM costs, other than for the California 20/20 Rebate Program for 2001.

27. After excluding DSM-related costs (other than the 20/20 Rebate Program Costs for 2001), the total DWR revenue requirement to be allocated among the service territories of the three major utilities using a cost of service approach is as follows: for PG&E's service territory in the amount of $6,532,650,000; for Edison's service territory in the amount of $4,017,786,000, and the remaining

allocation to SDG&E's service territory in the amount of $1,536,351,000, as derived in Table A-8.

28. The allocation of DWR revenues among the three utilities, as implemented in this decision, results in separate DWR cents per kWh charges of 13.99 for PG&E's service territory, 10.03 for Edison's service territory, and 9.02 for SDG&E's service territory.

29. The DWR cents per kWh charges are computed by dividing the allocated DWR revenue requirement for each utility's service territory by the applicable kWh sales billed, as shown in Table A-8.

30. DWR agrees to track its net short energy purchases and ancillary service purchases to compare against the projected accruals of the revenue requirement and will update projections on a monthly basis.

31. DWR's monthly monitoring will be used to determine if there should be any adjustment, up or down, in the revenue requirement and the associated recovery of that revenue requirement from the customers of the respective utility service territories.

32. For PG&E and Edison, the applicable kWh sales for computing the DWR charges cover the period from June 1, 2001 through December 31, 2002. For SDG&E, the applicable kWh sales for computing the DWR charges cover the period from September 15, 2001 through December 31, 2002.

33. Since the instant order will take effect on September 15, 2001, it may be necessary for PG&E to remit to DWR additional payments for DWR energy delivered to customers on and after June 1, 2001 and billed prior to September 15, 2001.

34. PG&E may have to apply a charge of 4.00 cents per kWh to each billed kWh of DWR sales for that period. The 4.00 cent charge is equal to the DWR

charge of 13.99, minus PG&E's generation-related rate of 6.47 and PG&E's average energy surcharge of 3.52 cents per kWh.

35. For Edison, there is no need to remit additional payment to DWR for the period between June 1 and September 15, because the sum of Edison's generation rate and the average energy surcharge is greater than 10.03 cents.

36. The "imputed utility rate" refers to the amount that the utility is entitled to receive for its own account for the kWhs that it supplies to its retail customers.

Conclusions of Law

1. Under the provisions of Water Code Section 80110, it is within the authority of the DWR to conduct and determine any just and reasonable review of its revenue requirement pursuant to Public Utilities Code Section 451.

2. DWR is entitled to payment for its revenue requirement associated with power it purchases and sells to retail end-use customers pursuant to Division 27 of the California Water Code.

3. Pursuant to the mandates of AB1X, a revenue requirement for DWR should be implemented.

4. The DSM costs that DWR has included in the revenue requirement are not included as authorized costs under AB1X.

5. Based on the amounts that DWR has submitted to be just and reasonable pursuant to its authority under Water Code Section 80110, the total revenue requirement to be implemented, exclusive of certain DSM-related costs, totals $12.087 billion for the service areas of all three major utilities, covering the period January 2001 through December 2002.

6. DWR should be entitled to recover revenues in an amount equal to the number of kWh sold by DWR to customers in the service territories of PG&E,

Edison, and SDG&E, respectively, multiplied by the relevant charges as set forth in the Ordering Paragraph (O.P.) 3 below, and also in O.P. 4 and 5.

7. Based upon the estimates of URG revenue requirements that have been submitted as testimony in that phase by PG&E and Edison, there is a range of potential outcomes that could be decided by the Commission that could result in either a shortfall or surplus of revenues for PG&E or Edison, respectively.

8. The effect of this order on the need for retail rate increases for PG&E or Edison cannot be determined until the URG phase of this docket is completed.

9. The effect of this order on the need for interim retail rate increases for SDG&E is subject to consideration in a separate docket (A.00-10-045 et. al.)

10. It is not reasonable to adopt the DWR-proposed "postage stamp" allocations of revenue requirement among the service areas of the three utilities.

11. It is reasonable to adopt a cost-based revenue allocation of the DWR revenue requirement and related DWR charges to be applied among the service areas of the three utilities as set forth in Table A-8.

12. The goal of our cost allocation is that electricity customers in each utility's service territory pay for the cost of DWR service in that territory.

13. A process should be established whereby the actual costs incurred in each service territory will be compared with the costs that were previously projected in order to set future DWR charges.

14. DWR's periodic adjustment to its revenue requirement should reflect the variances between actual and forecasted costs, and take into account actual and projected fund balances.

15. In order to perform its responsibilities to adjust DWR's revenue requirement, the Commission needs separate cost information for each utility

service territory, as well as a comparison of projected and actual revenues from end use customers in each service territory.

16. In order to facilitate independent charges that will be segregated and remitted directly to DWR, a separate per kWh charge should be used in computing the revenue to be forwarded to DWR by each utility on a monthly basis.

17. To ensure that the utility recovers its imputed utility rate, the utilities should be authorized to establish balancing accounts.

18. The utilities continue to have the obligation to serve pursuant to Public Utilities Code § 451 and Water Code Section 80002.

19. The public interest in resolving California's energy crisis and in timely issuing the bonds to support DWR's power purchase program outweighs the public interest in having a full 30-day comment period.

O R D E R

IT IS ORDERED that:

1. The revenue requirement of the California Department of Water (DWR) in the amount of $12,086,786,000 is hereby implemented as provided in the following ordering paragraphs, covering the period January 17, 2001 through December 31, 2002.

2. The total DWR revenue requirement is hereby allocated among the service territories of three major utilities as follows: for the service territory of Pacific Gas and Electric Company (PG&E) in the amount of $6,532,650,000; for the service territory of Southern California Edison Company (Edison) in the amount of $4,017,786,000; and the remaining allocation to the service territory of San Diego

Gas and Electric Company (SDG&E) in the amount of $1,536,351,000, as derived in Table A-8.

3. PG&E, Edison, and SDG&E are directed to begin disbursement of proceeds to DWR, as required by their respective servicing agreements or commission order, using the respective charges in cents per kWh of 13.99 for PG&E, 10.03 for Edison and 9.02 for SDG&E. These charges shall apply to each DWR-supplied kWh included on bills rendered on or after September 15, 2001 .

4. The cents per kWh charges referenced in ordering paragraph 3 above shall remain in effect for each utility through May 31, 2002 (unless DWR indicates an earlier adjustment is needed), and shall provide recovery of the DWR revenue requirement applicable through that period. Updated DWR charges shall take effect for each of the utilities beginning on June 1, 2002, covering the DWR revenue requirement for the forecast period from June 1, 2002 through May 31, 2003.

5. To the extent that PG&E has not already done so, PG&E shall remit additional payments to DWR representing DWR power delivered on and after June 1, 2001 and billed prior to September 15, 2001. These payments, if any, shall be based on a charge of 4.00 cents per kWh for each billed kWh of DWR sales during that period. The 4.00 charge is equal to the DWR charge of 13.99, minus PG&E's generation-related rate of 6.47 and the average energy surcharge of 3.52 cents per kWh. To the extent that PG&E has already collected these sums from retail end-use customers, it shall forward them to DWR within 10 calendar days of the effective date of this order. All other sums to be forwarded to DWR pursuant to this ordering paragraph shall be sent at the time specified in the servicing agreement that the Commission has ordered PG&E to comply with.

6. Each of the three utilities shall establish balancing accounts and shall book into the balancing account the difference between the imputed utility rate based on today's decision and the effective rate it has billed, multiplied by the number of utility-supplied kWhs billed at that effective rate. The balancing accounts shall be trued up, pursuant to a subsequent Commission order, no later than during the next update proceeding for DWR scheduled for February 1, 2002.

7. Consistent with the discussion in this decision, further proceedings shall be conducted in these dockets to consider possible revisions to the allocation of DWR costs among utility service territories.

8. The schedule for the next update of DWR revenue requirement shall be set for February 1, 2002, with DWR charges to be revised effective June 1, 2002. The ALJ shall issue a ruling establishing any necessary further procedural details as to the manner and process for the update proceeding.

This order is effective today.

Dated ______________, at San Francisco, California.

APPENDIX A

Appendix A

DWR's Revenue Requirement
For the Period January 2001 through December 2002

This Appendix sets forth the details supporting DWR's revenue requirement as updated on August 7, 2001. Table A below sets forth DWR's proposed method of recovery of its revenue requirement in terms of the separate allocation assigned to each of the three investor-owned utilities using its "postage-stamp" method.

Bond proceeds are applied using DWR's method, as indicated below, to supplement revenue from the customers to the DWR such that the net utility customers' revenue requirement fall within the retail rate adjustments adopted by the Commission for PG&E and Edison, and assumes a comparable rate adjustment for SDG&E.

Table A
DWR Revenue Recovery by Service Area
($000s)

PG&E			SCE			SDG&E		
Retail Sales (GWhs)	Customer Revenue Recovery	Bond Proceeds	Retail Sales (GWhs)	Customer Revenue Recovery	Bond Proceeds	Retail Sales (GWhs)	Customer Revenue Recovery	Bond Proceeds
55,417	5,927,784	4,955,370	42,037	4,604,161	3,758,953	18,631	2,068,441	1,665,962

Table A-1 below sets forth DWR's revenue requirement to be collected in the aggregate from customers of all three investor owned utilities shown on a quarterly basis. The total customer revenue requirement column reflects $12.6 billion over the two-year period. The difference between total DWR expenditures and customer revenue requirement is attributable to bond proceeds that are applied to offset current revenue requirements collected from customers. Table A-2 sets forth the allocation of the aggregate revenue requirement among the investor-owned utilities by quarter.

Table A-1
DWR Revenue Requirement
($000s)

Quarter	Retail Sales (GWhs)	Financing Cost	Total Expenditures	Customer Revenue Requirement	Spot Sales	Quarterly Power Fund Flow	Net Bond Proceeds	Fund Balance
Q1, 2001	12,995	3,888	2,346,142	872,028	-	(2,106,537)	-	(2,106,537)
Q2, 2001	18,413	57,100	5,494,743	2,094,831	-	(4,647,477)	-	(6,754,014)
Q3, 2001	15,029	113,086	3,661,813	1,709,786	30,417	(2,294,227)	-	(9,048,241)
Q4, 2001	14,148	73,662	2,550,856	1,609,605	45,691	(221,336)	10,380,285	1,110,708
Q1, 2002	12,692	(30,094)	1,646,935	1,443,922	46,708	442,322	-	1,553,031
Q2, 2002	12,465	(37,243)	1,374,519	1,418,080	69,174	570,627	-	2,123,658
Q3, 2002	15,878	32,049	2,327,956	1,806,475	183,458	(220,840)	-	1,902,818
Q4, 2002	14,465	157,247	2,042,958	1,645,660	101,508	(130,270)	-	1,772,548
Total	116,084	369,694	21,445,923	12,600,386	476,958	(8,607,737)	10,380,285	

Table A-2
DWR Revenue Recovery by Service Area
($000s)

	PG&E		SCE		SDG&E	
Quarter	Retail Sales (GWhs)	Customer Revenue Recovery	Retail Sales (GWhs)	Customer Revenue Recovery	Retail Sales (GWhs)	Customer Revenue Recovery
Q1, 2001	8,077	542,003	3,822	256,462	1,096	73,563
Q2, 2001	11,601	1,319,835	4,893	556,693	1,919	218,302
Q3, 2001	6,321	719,188	6,264	712,687	2,443	277,910
Q4, 2001	6,864	780,906	4,936	561,608	2,348	267,090
Q1, 2002	6,078	691,501	4,099	466,361	2,514	286,060
Q2, 2002	3,980	452,819	5,822	662,416	2,662	302,846
Q3, 2002	5,625	639,895	7,260	825,979	2,994	340,600
Q4, 2002	6,870	781,635	4,939	561,954	2,655	302,071
Total	55,417	5,927,784	42,037	4,604,161	18,631	2,068,441

BREAKDOWN OF DWR'S REVENUE REQUIREMENT IN ACCORDANCE WITH THE PROPOSED RATE AGREEMENT COST CATEGORIES

The following tables summarize the component costs of the DWR's "Total Expenditures" as set forth in Table A-1 above. The "Total Expenditures" include only categories of costs as set forth in the proposed Rate Agreement between DWR and the Commission. Table A-3 through Table A-6 below summarize the cost components on an aggregated basis for all three utilities (Table A-3) and for each separate utility, based on its respective allocation (Tables A-4 through A-6). Table A-7 provides the assumptions that were used in contract power purchases regarding natural gas fuel prices.

Table A-3
DWR Expenditure Summary
($000s)

	A	B	C	D	E	F	G	H	I	J	K	L	M
Quarter	Retail Sales (GWhs)	A&G	Uncollectable Allowance	DSM	Contract Power	Residual Net Short	Ancillary Services	Total Commitments	(Lag) Lead Accrual to Cash	Total Operating Expenditures	Financing Cost	Total Expenditures	Customer Revenue Recovery
Q1, 2001	12,995	6,250	--	--	--	3,792,565	--	3,798,815	(1,456,561)	2,342,254	3,888	2,346,142	872,028
Q2, 2001	18,413	6,250	--	114,000	3,253,659	1,645,940	--	5,019,849	417,794	5,437,643	57,100	5,494,743	2,094,831
Q3, 2001	15,029	6,250	4,230	338,400	1,527,776	883,722	152,624	2,913,003	635,725	3,548,727	113,086	3,661,813	1,709,786
Q4, 2001	14,148	6,250	6,548	--	833,161	1,046,841	209,237	2,102,037	375,157	2,477,194	73,662	2,550,856	1,609,605
Q1, 2002	12,692	6,406	6,054	--	812,169	601,191	165,418	1,591,238	85,791	1,677,029	(30,094)	1,646,935	1,443,922
Q2, 2002	12,465	6,406	6,044	102,800	837,379	429,725	153,945	1,536,299	(124,536)	1,411,763	(37,243)	1,374,519	1,418,080
Q3, 2002	15,878	6,406	7,025	308,400	1,259,913	635,151	198,503	2,415,398	(119,491)	2,295,906	32,049	2,327,956	1,806,475
Q4, 2002	14,465	6,406	5,242	--	1,181,565	402,345	177,132	1,772,690	113,022	1,885,712	157,247	2,042,958	1,645,660
Total	116,084	50,625	35,142	863,600	9,705,622	9,437,481	1,056,859	21,149,329	(73,100)	21,076,228	369,694	21,445,923	12,600,386

Table A-4
DWR Expenditure Summary PGE Service Area Allocation
($000s)

	A	B	C	D	E	F	G	H	I	J	K	L	M
Quarter	**Retail Sales (GWhs)**	**A&G**	**Uncollectable Allowance**	**DSM**	**Contract Power**	**Residual Net Short**	**Ancillary Services**	**Total Commitments**	**(Lag) Lead Accrual to Cash**	**Total Operating Expenditures**	**Financing Cost**	**Total Expenditures**	**Customer Revenue Recovery**
Q1, 2001	8,077	3,892	--	--	--	2,357,200	--	2,361,092	(904,483)	1,456,609	2,426	1,459,035	542,003
Q2, 2001	11,601	3,942	--	71,286	2,050,616	1,041,699	--	3,167,543	266,671	3,434,214	35,761	3,469,975	1,319,835
Q3, 2001	6,321	2,638	1,722	142,854	650,631	375,306	61,105	1,234,256	263,159	1,497,416	47,678	1,545,094	719,188
Q4, 2001	6,864	3,064	3,190	--	408,465	511,500	102,630	1,028,850	171,881	1,200,731	33,263	1,233,994	780,906
Q1, 2002	6,078	3,052	2,893	--	386,951	292,783	79,193	764,873	42,213	807,086	(14,295)	792,790	691,501
Q2, 2002	3,980	2,057	1,932	26,370	267,017	133,195	48,962	479,533	(32,942)	446,590	(11,885)	434,705	452,819
Q3, 2002	5,625	2,244	2,427	108,025	440,934	225,152	69,510	848,294	(34,697)	813,597	15,964	829,562	639,895
Q4, 2002	6,870	3,051	2,490	--	562,198	190,173	84,272	842,184	49,938	892,123	74,914	967,037	781,635
Total	55,417	23,942	14,654	348,535	4,766,813	5,127,008	445,672	10,726,625	(178,259)	10,548,366	183,827	10,732,192	5,927,784

Table A-5
DWR Expenditure Summary Edison Service Area Allocation
($000s)

	A	B	C	D	E	F	G	H	I	J	K	L	M
Quarter	**Retail Sales (GWhs)**	**A&G**	**Uncollectable Allowance**	**DSM**	**Contract Power**	**Residual Net Short**	**Ancillary Services**	**Total Commitments**	**(Lag) Lead Accrual to Cash**	**Total Operating Expenditures**	**Financing Cost**	**Total Expenditures**	**Customer Revenue Recovery**
Q1, 2001	3,822	1,834	--	--	--	1,115,417	--	1,117,251	(429,794)	687,457	1,133	688,590	256,462
Q2, 2001	4,893	1,659	--	31,152	863,406	432,193	--	1,328,410	110,223	1,438,633	15,390	1,454,023	556,693
Q3, 2001	6,264	2,599	1,801	140,727	631,458	365,853	65,756	1,208,194	268,183	1,476,377	47,054	1,523,431	712,687
Q4, 2001	4,936	2,148	2,271	--	286,258	361,376	71,832	723,884	142,244	866,128	28,450	894,579	561,608
Q1, 2002	4,099	2,080	1,959	--	263,567	190,960	53,431	511,998	27,003	539,001	(9,800)	529,202	466,361
Q2, 2002	5,822	2,982	2,822	53,560	391,457	204,173	72,074	727,068	(64,060)	663,008	(17,403)	645,605	662,416
Q3, 2002	7,260	2,950	3,260	141,997	580,407	290,256	91,411	1,110,282	(60,809)	1,049,472	10,980	1,060,452	825,979
Q4, 2002	4,939	2,177	1,789		402,224	138,565	60,312	605,066	43,311	648,377	53,415	701,792	561,954
Total	42,037	18,428	13,902	367,436	3,418,778	3,098,794	414,816	7,332,154	36,299	7,368,453	129,220	7,497,673	4,604,161

Table A-6
DWR Expenditure Summary SDG&E Service Area Allocation
($000s)

	A	B	C	D	E	F	G	H	I	J	K	L	M
Quarter	**Retail Sales (GWhs)**	**A&G**	**Uncollectable Allowance**	**DSM**	**Contract Power**	**Residual Net Short**	**Ancillary Services**	**Total Commitments**	**(Lag) Lead Accrual to Cash**	**Total Operating Expenditures**	**Financing Cost**	**Total Expenditures**	**Customer Revenue Recovery**
Q1, 2001	1,096	524	--	--	--	319,948	--	320,472	(122,283)	198,189	329	198,517	73,563
Q2, 2001	1,919	649	--	11,562	339,636	172,049	--	523,896	40,900	564,796	5,948	570,745	218,302
Q3, 2001	2,443	1,012	707	54,819	245,687	142,563	25,764	470,552	104,383	574,935	18,353	593,289	277,910
Q4, 2001	2,348	1,038	1,087	--	138,437	173,964	34,775	349,302	61,032	410,335	11,948	422,283	267,090
Q1, 2002	2,514	1,274	1,201	--	161,651	117,447	32,793	314,367	16,575	330,942	(5,999)	324,942	286,060
Q2, 2002	2,662	1,367	1,291	22,870	178,904	92,357	32,909	329,698	(27,534)	302,164	(7,955)	294,209	302,846
Q3, 2002	2,994	1,213	1,337	58,377	238,571	119,743	37,582	456,822	(23,985)	432,837	5,106	437,943	340,600
Q4, 2002	2,655	1,178	962	--	217,143	73,608	32,548	325,439	19,773	345,212	28,918	374,130	302,071
Total	18,631	8,255	6,586	147,629	1,520,031	1,211,679	196,371	3,090,550	68,860	3,159,409	56,648	3,216,057	2,068,441

Table A-7
Gas Price $/MBTU

Quarter	SC Border	Malin	City Gate
Q3, 2001	$ 7.22	$ 3.61	$ 5.64
Q4, 2001	$ 7.68	$ 3.47	$ 5.43
Q1, 2002	$ 6.86	$ 3.49	$ 5.46
Q2, 2002	$ 6.94	$ 3.63	$ 5.66
Q3, 2002	$ 6.75	$ 4.72	$ 6.52
Q4, 2002	$ 7.15	$ 5.94	$ 7.15

TABLE A-8

COMPARISON OF DWR and CPUC REVENUE ALLOCATIONS

DWR REQUEST

Line No.		PG&E	SCE	SDG&E	Total
1	Total DWR Costs	$10,883,153	$8,363,114	$3,734,403	$22,980,671
2	minus: Bond Proceeds	$4,955,370	$3,758,953	$1,665,962	$10,380,285
3	equals: Ratepayer Revenue Requirement	$5,927,784	$4,604,161	$2,068,441	$12,600,386
4	Rate on DWR sales (cents / kWh)	11.377	11.377	11.377	
5	DWR Sales (GWh)	55,417	42,037	18,631	116,084

COST-BASED ALLOCATION--with All DSM and 2002 "20/20"Costs Removed

Line No.		PG&E	SCE	SDG&E	Total
1	Total DWR Costs	$12,142,972	$7,468,311	$2,855,788	$22,467,071
2	minus: Bond Proceeds	$5,610,322	$3,450,525	$1,319,437	$10,380,285
3	equals: Ratepayer Revenue Requirement	$6,532,650	$4,017,786	$1,536,351	$12,086,786
	Rate Calculation:				
4	**Ratepayer Revenue Requirement**	$6,532,650	$4,017,786	$1,536,351	$12,086,786
5	Less: **Generation Revenues to DWR** (Jan 17-May 31 for PG&E and Edison, Feb 7-Sept 15 for SDG&E)	$1,048,949	$523,903	$310,033	$1,882,886
6	Equals: **Revenues to be collected** (June 1 onward for PG&E and SCE, September 15 onward for SDG&E)	$5,483,701	$3,493,882	$1,226,317	$10,203,900
7	**DWR Sales** (June 1 onward for PG&E and SCE, September 15 onward for SDG&E) (GWh)	39,207	34,837	13,600	
8	**Rate on DWR sales** (June 1 onward for PG&E and SCE, September 15 onward for SDG&E) (cents / kWh)	13.987	10.029	9.017	

APPENDIX B

Appendix B
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Summary of Cost Categories Referenced in Rate Agreement

The summary below describes how, where applicable, each of the cost categories referenced in the Rate Agreement between DWR and the Commission (see Article 1-Definitions) are reflected in the derivation of the cost elements in Tables A-1 through A-6 of Appendix A of this decision.

1. **Cost for the purchase and delivery of power, including:**

- **Long-term purchases**

Long-term purchases are considered those which are more than a quarter in duration. These costs are included in Column E “Contract Power” as shown in Tables A-3 through A-6. The contracts which have been executed, or agreements in principle which were still under active negotiation as of June 15, 2001 are included in this column.

- **Short-term purchases**

Short-term purchases consist of two categories: (1) bilateral contracts with a duration of a quarter or less, but longer than day-ahead purchases, which are included through the third quarter of 2001 in Column E, “Contract Power”, for known contracts as of June 15, 2001, and (2) day ahead, hour ahead, real time, or future, yet to be completed bilateral contracts not known as of June 15, 2001.

- **Termination & liquidated damages**

Termination charges are those applicable to the Department for terminating contracts prior to the end of the term of the agreement for various reasons, for which the contract provides for charges to be paid by the Department to the Seller, or for similar charges due from the Seller to the Department for Seller’s early termination for certain purposes. Liquidated damages (payment of monies due to actions taken by the Department or the Seller in accordance with certain contract provisions rather than providing for costs to be determined by a court of law or arbitration). No termination charges or liquidated damage costs are specifically assumed in the Department’s Revenue Requirement (no costs to the Department, nor any payments to the Department by any Seller for such theoretical charges).

- **Emission costs**

Allowances for emission costs are included in the generation dispatch model and are included in the estimated cost of power. These costs are not readily separable in the model due to the manner in which the model program computes the costs.

- **Hour-ahead power**

Hour-ahead purchases, whether by the Department or the ISO, are included in Column F of Tables A-3 through A-6 as part of “Residual Net Short” purchases. Residual Net Short purchases are all net short energy purchases other than Ancillary Services which are required in addition to the Department’s power purchases under bilateral contracts.

- **Real time power**

Real time power purchases by the ISO and DWR are also included in "Residual Net Short" purchases in Column F in Tables A-3 through A-6.

- **Transmission, distribution, scheduling**

Allowance for distribution and transmission line losses is included in the calculation of the quantity of net short energy required to be purchased to meet the retail customer loads of the IOUs. There are not separate charges estimated in the net short energy costs. As noted in Exhibit A, sellers are responsible for their own scheduling coordination costs and the IOUs are responsible for their costs of scheduling the load. Any of the Department's costs for coordination and scheduling are captured in the labor and related costs included in "Administrative & General or "A&G" charges shown in Column B of Tables A-3 through A-6.

- **Ancillary services**

The ancillary services charges incurred each month are shown in column G. These charges are estimated at 6% of the total cost of the energy purchased in columns E and F. The four ancillary services in California are Regulation Reserves (Regulation), Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves. The first three correspond to services defined in FERC Order 888 as regulation, spinning, and supplemental reserves. The fourth, Replacement Reserves, is not explicitly defined or required under FERC Order 888, but was defined to satisfy WSCC requirements. Based on historical analysis these ancillary services charges approximate 6% of the cost of power.

2. **Costs for fuel, including storage & transportation, options, and financial instruments.**

   The cost of fuel for the contracted power is included in Column E in Tables A-3 through A-6. The cost of fuel is also included in the short-term purchases included in the "Residual Net Short" in Column F in Tables A-3 though A-6. Table A-7 shows the cost of natural gas assumed in the cost of power for long-term contracts and for short-term spot purchase market clearing price assumptions.

   Fuel transportation charges are estimated in the generation dispatch model based upon regional location of generating sources and are included in the cost of power shown in Columns E and F in Tables A-3 through A-6. Although the Department may have rights to implement option and financial hedging programs and instruments, no such actions or associated costs are specifically assumed in the fuel costs herein. All fuel costs included in the contracts and the spot market purchases are assumed to be equal to the average spot market price of natural gas.

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3. Costs to avoid or minimize the amount of power to be acquired including:

- conservation programs
- load curtailment/interruptible programs
- conservation rebates
- load management programs

See Exhibit B of DWR's August 7, 2001 update for the description of the programs, the amount of savings in MWh per month, and the associated costs for these programs and savings. These costs are shown in the aggregate by month in Column D in Tables A-3 though A-6 of Appendix A of this decision.

4. Payments under security agreements

There are no specific security agreement payments assumed to be payable during the term of the Department's Revenue Requirement as filed herein.

5. Administrative, general & overhead expenses

The Department's A&G (administrative and overhead) expenses are as described in Exhibit A, and as summarized by month as Column B in Tables A-3 through A-6.

6. Insurance premiums

Insurance premiums are included in A&G expenses in Column B in Tables A-3 through A-6.

7. Payments for employee benefits

These costs are included in the A&G expenses in Column B in Tables A-3 through A-6.

8. Legal & engineering expenses

These costs are included in A&G expenses in Column B in Tables A-3 through A-6.

9. Consulting & technical services

These costs are included in A&G expenses in Column B in Tables A-3 through A-6.

10. Charges for licenses, orders or other governmental mandates

There are no specific charges estimated or included in the Department's Revenue Requirement as filed.

11. Taxes, governmental charges, etc.

There are no known applicable taxes or governmental charges that can be estimated as of the date of this filing, and none were included in DWR's revenue requirement.

12. Expenses, liabilities, compensation of trustees and other fiduciaries

Any such charges to be incurred during the period covered by this revenue requirement filing are anticipated to be those associated with the issuance of the DWR's bonds and would be paid from bond proceeds.

13. Costs of complying with any rebate requirements relating to the Bonds

No such costs are included during the term of this revenue requirement filing.

14. Deposits to fund or replenish operating reserves

Initial deposits to fund operating reserves are capitalized in the DWR's bond issue. Operating reserves would need to be replenished only if actual costs end up being significantly higher than the assumptions that underlie the DWR's revenue requirement as presented in its filing. Therefore, there are no assumed replenishment costs in DWR's revenue requirement submittal.

(END OF APPENDIX B)

APPENDIX C

DWR Revenue Recovery and Average Charge per kWh by Service Area

	PG&E			SCE			SDG&E		
Quarter	Retail Sales (GWhs)	Customer Revenue Recovery ($000s)	Average Charge per kWh ($)	Retail Sales (GWhs)	Customer Revenue Recovery ($000s)	Average Charge per kWh ($)	Retail Sales (GWhs)	Customer Revenue Recovery ($000s)	Average Charge per kWh ($)
Q1, 2001	8,077	522,663	0.06471	3,822	278,110	0.07277	1,096	54,323	0.04955
Q2, 2001	11,601	1,011,345	0.08718	4,893	397,786	0.08129	1,919	124,723	0.06500
Q3, 2001	6,321	884,165	0.13987	6,264	628,256	0.10029	2,443	169,540	0.06941
Q4, 2001	6,864	960,040	0.13987	4,936	495,075	0.10029	2,348	211,682	0.09017
Q1, 2002	6,078	850,126	0.13987	4,099	411,111	0.10029	2,514	226,716	0.09017
Q2, 2002	3,980	556,692	0.13987	5,822	583,940	0.10029	2,662	240,020	0.09017
Q3, 2002	5,625	786,683	0.13987	7,260	728,127	0.10029	2,994	269,942	0.09017
Q4, 2002	6,870	960,936	0.13987	4,939	495,380	0.10029	2,655	239,406	0.09017
Total	**55,417**	**6,532,650**		**42,037**	**4,017,786**		**18,631**	**1,536,351**	

Notes

1. PG&E and Edison charge for Q2, 2001 is a weighted average of the generation charge for April and May, and the adopted DWR charge for June
2. SDG&E charge for Q3, 2001 is a weighted average of the generation charge through September 14, and the adopted DWR charge for September 15 through September 30

(END OF APPENDIX C)

APPENDIX D
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Comments on Specific Cost Assumptions

1. Ancillary Services

DWR's estimate of ancillary service cost is $1.057 billion. (See Appendix A, Table A-3.) Ancillary service costs are related to delivery of bulk wholesale power to satisfy each utility's aggregate load requirement. DWR's ancillary service cost estimate is based on the following assumptions:

- From January 2001 through June 2002, DWR provides "full requirement" power to customers, and thus assumes responsibility for all ancillary service costs associated with DWR delivered power. These cost are included in spot energy cost.
- The ancillary services from January through June 2001 are estimated at $600 million. In addition, DWR included a $170 million expense to cover additional charges for ancillary services through June 2001. This $770 million in ancillary service costs prior to July 2001 are reflected in the "residual net short" column of Table A-3 of Appendix A for the first and second quarters of 2001. (See August 7, 2001 update, Ex. C, p. C-3.)

- For the period July 2001 through December 2002, DWR will provide all ancillary services for DWR and IOU supplied power, estimated at 6% of the sum of contract and spot energy costs plus the cost of URG.
- DWR assumes that a servicing agreement between the utilities and DWR will allow the use of URG to provide ancillary services at the variable cost of URG. DWR will purchase any
- additional ancillary services not provided by URG.

Edison argues that DWR's assumptions regarding cost responsibility for ancillary services are internally inconsistent, such that Edison cannot determine whether DWR's assumptions cover all of the costs DWR is likely to incur. Based upon different representations made by DWR, the beginning date for DWR to assume responsibility for ancillary services is either January 17, 2001, July 1, 2001, or April 6, 2001.

DWR has not been able to obtain adequate information from the ISO regarding ISO ancillary service costs and other procurement related costs, for which the non-creditworthy utilities are not financially responsible under the creditworthiness provisions of the FERC tariffs. DWR has not been able to agree upon a methodology to avoid double-billing by DWR and the ISO of individual ISO ancillary services. (DWR August 1, 2001 letter to CPUC, IOU7 data request response, p. 6; IOU14 data request response, p. 11; IOU15 and IOU16 data request responses, pp. 3-24.)

DWR has stated in its July 26, 2001 response to Commissioner Brown (p. 2) and in its August 1, 2001 data response to the utilities (IOU7, IOU16), that it accepts responsibility for the FERC Order 888 definition of ancillary services and for unaccounted for energy. PG&E questions, however, whether that includes all costs from January 17, 2001. At the July 27 CPUC workshop, DWR also stated that it accepts responsibility for congestion costs from January 17, but not for ISO neutrality charges. Until there is resolution of the uncertainty regarding cost responsibility between DWR and the ISO for all ISO related charges from the date PG&E became non-creditworthy, PG&E states it cannot precisely estimate additional ISO-related costs that may not yet be included in its URG request.

TURN claims that DWR's ancillary services estimate is too high because it is based on the entire period during which the market was in place. As such, TURN says that DWR includes a period of time (April, 1998 through 2000) when all ancillary services were purchased by the ISO and there was no self-provision by URG. TURN further states that since the beginning of 2001, URG has self-provided ancillary services to the extent feasible, and thus, the total quantity of ancillary services purchased in the market has declined significantly. However, TURN notes that the DWR estimate does not factor in this decline in quantity purchased. In addition, TURN states that there were problems in the interface between PG&E and the ISO that caused PG&E to withdraw temporarily from certain ancillary service markets early in 2001. However, TURN's review of ISO data indicates an increase in self-provision in recent months.

In addition, based on its review of ISO pricing data for the month of June, TURN believes that the ISO's ancillary service purchases appear to have fallen significantly in cost as a result of the FERC order in mid-June. In part, TURN notes that this results from the application of the price cap to ancillary services as well as real energy. Since ancillary services are purchased in short-term markets, they are most sensitive to trends in spot energy prices. Because the DWR contracts for this summer are considerably higher than the FERC price cap, TURN argues they should not be used to measure the price of ancillary services, which is constrained by the cap as well as by short-term market conditions.

TURN notes that SDG&E, with no self-provision, has forecast DWR-provided ancillary services at 4.77% of spot market costs. (See A.00-11-45, Prepared Testimony of Michael Strong on behalf of SDG&E, Attachment 3.) With spot market prices behaving more reasonably due to long-term contracts, better supply-demand balance, and the FERC rate cap, TURN claims this price is likely to be lower than DWR's estimate of 6% of total costs, including self-provision. In order to develop a forecast of ancillary services costs, TURN therefore recommends a figure based on 4.77% of spot market prices <u>if</u> all were provided by the market. TURN would then subtract the self-provision amounts. TURN proposes that DWR estimate the amount to be self-provided by each utility (by type and cost of resource – *e.g.*, regulation, spin, non-spin, replacement reserve) and subtract that amount.

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DWR's revenue requirement includes an allowance for the self-provision of a portion of ancillary services by PG&E and Edison, and market purchases of ancillary services which are not self-provided (SDG&E has no generating resources which can self-provide ancillary services). DWR believes that its estimates of ancillary service costs at 6% of total energy supply costs are borne out by recent history. DWR has no assurance of its ability to contract for ancillary services other than through spot purchases, although efforts are underway to seek to meet a portion of capacity reserves through short-term or potentially seasonal contracts.

DWR agrees that the ancillary service costs should be lower in the future because of the reduction in spot market prices, and states that this is reflected in DWR's projection of ancillary service costs included in the August 7 revenue requirement. The absolute cost of ancillary services is projected to be significantly below recent historical prices using the method described in DWR's revenue requirement filing due to the projected drop in both contract prices and spot market prices as compared to recent historical prices. Since ancillary service costs are projected to be 6% of total energy purchase costs, the significantly lower cost of contract energy and projected spot market purchases compared to prices in the past year results in a corresponding drop in DWR's projected ancillary service costs.

In response to TURN's statement that PG&E customers should benefit from PG&E's self-provision of ancillary services, DWR notes that there is a trade-off in using hydroelectric resources to provide for capacity reserves rather than using that generating capability to meet net short energy requirements. The allocation of net short energy and ancillary service costs to the respective IOUs' retail customers would, under DWR's allocation, be in proportion to the net short energy requirements of each utility. Therefore, if PG&E used more of its hydroelectric resources to self-provide for its share of ancillary services (capacity reserves), then its volume of net short energy would increase, while ancillary service costs purchased by DWR on behalf of PG&E's customers would decrease.

DWR proposes to work with both PG&E and Edison to seek a balance between self-provision of ancillary services from the IOUs' respective owned-generation, and their respective share of the net short energy and associated ancillary service costs. Such cost tradeoffs would be reflected in any true-ups of the revenue requirement.

2. Grid Management Charges (GMC) Related to Procurement

DWR's revenue requirement filing does not provide for any Grid Management Charge (GMC) or other ISO-related charges ("uplift costs"). Specifically, in its August 1, 2001 response addressed to Paul Clanon of the Commission's Energy Division, DWR states:

> "It is assumed that each utility will be responsible for grid management charges and other miscellaneous ISO charges other than the FERC Order 888 ancillary service charges described in the DWR Revenue Requirement filing. These miscellaneous charges have not been specifically identified but will be set forth in the development of the operational protocols being established

> between DWR and each of the three utilities. DWR and the utilities are in the process of developing operational protocols to ascertain ISO charge and cost responsibilities and resource scheduling in a manner consistent with the development of the revenue requirement."[1]

Although it is actively negotiating with DWR to establish operating protocols and cost allocation responsibilities, Edison has not agreed upon the cost allocation that DWR has presented in its revenue requirement. With respect to GMC and uplift costs, Edison claims that DWR must be responsible for the majority of these costs due to Edison's non-creditworthiness status.[2]

In its URG Testimony, Edison forecasts that its annual combined GMC and uplift cost responsibility would be approximately $67 million, and that DWR would be responsible for approximately $269 million.[3] Edison argues that the failure of DWR to assume GMC and uplift cost responsibility creates an understated combined DWR-Edison revenue requirement of approximately $538 million ($269 million per year for two years). Edison argues that the Commission should not implement a revenue requirement without accounting for these GMC and uplift costs.

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[1] Memorandum from Thomas Hannigan (DWR) to Clanon (CPUC), dated August 1, 2001. (IOU7.)

[2] All uplift costs that are a result of market transactions require a creditworthy entity pursuant to FERC's various orders on this matter. Therefore, Edison claims it is unreasonable to expect that DWR will not be responsible for any uplift costs as the majority of such costs are market-related.

[3] Second Revised Errata, dated July 18, 2001, Revised Table III-7.

In its August 7 response to parties' comments, DWR reiterates that it does not view GMC as net short costs. DWR views the GMC as a responsibility of the load for use of the transmission system and not as a market purchase made by Edison from third party providers of energy service. DWR states that GMC is not a good or service that is required to be purchased from market participants and therefore, is not subject to the creditworthy purchaser concern noted by the FERC in its April 6, 2001 order. Therefore, DWR's updated revenue requirement excludes the GMC costs.

3. Franchise and Uncollectibles

DWR's July 23rd revenue requirement did not account for franchise fees and uncollectible accounts expense. In its updated revenue requirement, DWR added a provision for uncollectible accounts, but DWR still believes that franchise fees are the responsibility of the utilities, and not that of DWR.

Edison takes exception to DWR's exclusion of franchise fees from its revenue requirement calculation. Edison currently pays franchise fees to cities based on the total amount of revenues billed to customers (total revenues includes both Edison and DWR revenues). In order to collect a sufficient amount of revenue from customers to recover franchise fee payments, each unbundled rate component (*e.g.*, distribution, transmission, public purpose programs) is design-based on a revenue requirement that includes franchise fee payments. That is, each estimated revenue requirement is grossed up by the most recent Commission-approved factor to determine the revenue requirement that is used to set

rate levels. On a monthly basis, in the applicable ratemaking mechanism, the actual revenue that is generated from rate levels is reduced by a franchise fee amount calculated using the adopted factor. The revenues that remain after franchise fees are removed are then available to recover the costs associated with the applicable rate component.

Edison states that if this methodology is not applied to the DWR revenue requirement, the franchise fees that Edison is obligated to remit to cities will have to be recovered through another Edison rate component, such as distribution, transmission, or URG. Edison claims that such treatment would result in Edison undercollecting its own costs.

Edison argues that to appropriately establish the DWR revenue requirement and associated rate component, DWR's estimated revenue requirement should be grossed up by the currently effective franchise fee rate. Edison proposes that the revenues generated from the DWR rate component would first be reduced by the franchise fee factor and retained by Edison in order to recover franchise fee payments made by Edison to cities.

Edison believes that since the DWR rate component would be established based on the grossed up (including franchise fee payments) revenue requirement, reducing the amount of DWR revenue by this factor would still enable DWR to recover its revenue requirement. Edison maintains that the remaining revenue after accounting for franchise fees would be remitted to DWR for recovery of its incurred costs. Edison proposes to apply the same methodology to uncollectible accounts expense.

Edison calculates that implementing the Commission-adopted franchise fees and uncollectible accounts would result in Edison's share of the DWR revenue requirement (based on July 23rd data) being increased from $5.803 billion to $5.869 billion.

We make no judgment here with respect to the dispute over who is responsible for paying franchise fees relating to revenues generated from DWR sales. By virtue of implementing the revenue requirement for DWR without including a provision for franchise fees, we in no way endorse the views of DWR regarding liability for franchise fees nor prejudge any party's rights to seek further remedies to resolve this issue.

4. **Calculation of Net-Short**

Edison's Net Short

Edison claims that DWR's summary documentation of the projected net-short position for Edison for the period January 17, 2001 through December 31, 2002 appears to be internally inconsistent for 2002.[4] At an annual level for 2002, DWR's forecasts a 92,292,048 MWh unadjusted retail load and 79,357,717 MWh adjusted retail load for Edison. The

[4] Although the period covered by DWR's revenue requirement filing extends through December 31, 2002, DWR provided monthly load forecast assumptions through 2004, and the referenced internal load forecast inconsistency increases in 2003 and 2004. (Confidential response to Question IOU3 in DWR's August 1, 2001, response to Paul Clanon of the Energy Division.)

adjustments made account for the projected load reducing effects of the 20/20 program, AB 970, direct access, distributed generation, energy crisis conservation, and price elasticity conservation.[5] Edison claims that the adjustment should be the difference between the unadjusted and adjusted forecast loads, i.e., 92,292,048 MWh less 79,357,717 MWh equals 12,934,331 MWh. However, Edison states that the detailed schedule that was attached to the above referenced summary only reflects an adjustment of 11,124,683 MWh, or 1,809,648 MWh less than the adjustment reflected in the summary page of the response. Edison notes that this discrepancy does not exist for the 2001 data, but becomes significantly more pronounced with the forecast data provided for 2003 and 2004.

PG&E's "Net Short"

Based on informal discussions with DWR, PG&E believes that DWR's August 1 forecast of PG&E's net short for 2001- 2002, represented by the 48,078 GWh retail sales forecast, understated PG&E's actual net short for the period by approximately 5,000 GWhs. DWR's August 1, 2001, letter to the CPUC indicated that DWR's August 7 revision would reflect an increase in PG&E's net short to correct this error. An increase in DWR's forecast of PG&E's net short amount would have the effect of increasing DWR's revenue requirement, all else being equal.

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[5] Edison claims that because DWR's explanation for the basis of its load reduction assumptions related to distributed generation and AB 970 impacts was cursory at best, Edison cannot comment on the assumptions, except to note that the load reduction estimates are significant.

In its August 7 update, DWR states that having received updated information from PG&E regarding three bilateral contracts that were cancelled by sellers, DWR agrees that the forecast should be adjusted and has done so in its updated revenue requirement.

In its August 14 comments, PG&E states that it lacks sufficient information from DWR in order to confirm whether DWR's estimate of PG&E's monthly metered net short position is correct or not. PG&E believes, however, that DWR is overestimating the amount of the revenue requirement allocated to PG&E by approximately $1.4 billion.

5. The Amount of Revenues Paid by PG&E to DWR Between January 17, 2001 and the Current Date Under Prior Commission Decisions

PG&E believes that DWR's estimate of a $745 million shortfall in collections from PG&E for the 1st and 2nd quarters of 2001 is incorrect. (DWR August 1, 2001 letter to CPUC, data request response PG&E 6, p. 21.)

6. Forecast Gas Prices

The gas price assumptions underlying DWR's revenue requirement are set forth in Table A-7 of Appendix A of this decision. PG&E presented its own internal gas price forecasts, arguing that DWR's gas price forecast in its July 26, 2001 letter to Commissioner Brown, should be reduced by as much as 60 percent based on PG&E's more current forecasts.

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TURN also argues that DWR's gas price forecasts are too high, and do not fully reflect the decline in prices during the past June and July period. TURN recommends, as stated in its URG testimony, that gas price assumptions should be limited to $4.00 / MMBtu at Malin and $5.50 / MMBtu at the California border for the next 18 months.

DWR admits that its revenue requirement is based on gas price forecasts that exceed current industry forecasts. However, DWR argues that possible weather changes and winter hydroelectric shortages in the Northwest create a "significant potential for upward pressure on gas prices." (DWR August 1, 2001, letter to Commission.) Thus, DWR defends its forecasted gas prices, and declines to reduce them to reflect recent declines in gas prices. DWR believes the present gas prices in California reflect circumstances that are unlikely to continue over the next 18 months. DWR notes that June and July of this year have resulted in some of the lowest average temperatures in California for those months in recent history. DWR has been advised that it is likely a number of generators, energy marketers and other participants in the natural gas market held "long" positions in natural gas which placed substantial short-term pressure on spot market gas prices, thereby lowering daily spot prices.

DWR believes that a return to more normal August, September and October temperatures can be expected to drive up the demand for gas-fired generation. In addition, California, and to a greater extent the Pacific Northwest, will have far less hydroelectric generation capability as the summer progresses, placing more burden on gas-fired generation to meet higher peak period energy needs. DWR believes that projecting the long-term price of gas based on the extraordinary and unique circumstances that created the lower gas prices of June and July is as unreasonable as predicting $12/MMBtu gas prices for that same period based upon such average costs in the first five months of 2001. (*See* DWR August 7, 2001 Response to Comments.)

In the event gas prices remain at the present low levels for a protracted period, DWR agrees that it could make an adjustment to its revenue requirement accordingly, provided other cost factors do not increase the revenue requirement unexpectedly.

7. Responsibility for Unaccounted for Energy

PG&E, Edison and TURN have commented on the need for clarification of responsibility for neutrality and unaccounted for energy (UFE) costs. DWR states that SDG&E and DWR have agreed to the split of various ISO costs in a memorandum of understanding between SDG&E and DWR. In that agreement, neutrality and UFE costs are paid by SDG&E as part of a larger range of issues settled between the parties in that MOU. DWR asserts that it is not possible to separately estimate quarterly costs for UFE and neutrality between the IOU service territories due to the variation in such costs from month to month and quarter to quarter. For this reason, DWR has not separately estimated those costs. For the period of the revenue requirement ending December 2002, when DWR is expected to be responsible for purchasing all net short energy, the net short energy costs would include the Edison and SDG&E neutrality and UFE costs.

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DWR expects the full cooperation of the utilities and the ISO in evaluating the proper allocation of costs for neutrality and UFE to ensure that DWR is not being allocated costs for the municipal utilities' share of such costs.

DWR expects its estimates of the ancillary services costs in its revenue requirement to be sufficient to cover the neutrality and UFE costs. DWR agrees that these costs will need to be tracked to avoid the allocation of such costs to SDG&E customers, since those costs will be paid directly by SDG&E rather than through DWR. Due to the variability of such costs, and the fact that it is the ISO and not DWR who allocates such costs, the allocation of costs will need to be addressed in an after-the-fact true-up. DWR states that it will cooperate with the Commission to effect an appropriate true-up mechanism for these ISO charges for the period covered by the DWR revenue requirement. (See DWR August 7, 2001 Response to Comments.)

(END OF APPENDIX D)