Decision 02-12-045 December 17, 2002

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-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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OPINION ADOPTING INTERIM ALLOCATION OF THE 2003 REVENUE REQUIREMENT OF THE CALIFORNIA DEPARTMENT OF WATER RESOURCES

Summary

This decision allocates among the customers of the three major California utilities the cost of the California Department of Water Resources' (DWR) forecast 2003 revenue requirement for its power purchase program.[1]

The parties presented four different allocation methodologies. The allocation methodology proposed by the Commission's Office of Ratepayer Advocates (ORA) is the fairest, and we adopt it with modifications. In essence, the methodology we adopt pools the total costs of DWR's contracts and allocates those costs among the utilities on the basis of the quantity of energy supplied to each utility from the contracts. The resulting costs for each utility are remitted to DWR.

We also resolve a number of issues relating to how the allocation of the revenue requirement is calculated, including issues relating to the proper treatment of revenues from sales of excess energy, procurement of ancillary services, inclusion of funds for demand reduction efforts, and the use of particular modeling runs. Issues relating to the true-up of DWR's 2001-2002 revenue requirement will be addressed after actual data for 2002 becomes available, and are not resolved here.

Due to the mandatory expedited schedule for this proceeding, its complex interaction with other Commission proceedings, concerns about due process, and

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[1] The three major utilities are Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). For more background on DWR's power purchase program and revenue requirement, and on the relevant statutes, please see Decision (D.) 02-02-052, pp. 6-12.

the constantly evolving nature of the California electricity market, the evidentiary record does not support a final allocation of DWR's revenue requirement for all of 2003. Accordingly, the allocation we adopt today is interim, and will be superseded by a later allocation. We believe that a final allocation for 2003 can be achieved expeditiously, but it will require additional input from DWR.

As described below in more detail, in order for us to optimize our allocation for 2003, we need DWR to update it's modeling efforts to incorporate direct access migration, to provide all parties an equal opportunity to contribute to the modeling assumptions and inputs, to treat sales of excess energy consistently with the protocols adopted in D.02-09-053, and to refine assumptions regarding ancillary services and cash reserve levels. We cannot require DWR to submit a supplemental revenue requirement determination for 2003, but we need a supplemental determination if our allocation is to be as fair and comprehensive as possible. Without such cooperation and timely resubmittal from DWR, we may be required to set the costs charged to ratepayers at a rate that is more than a billion dollars more than is necessary. Such an unnecessary burden on ratepayers must be avoided to prevent significant harm to individuals, businesses, and the economy of California.

While it is up to DWR to manage its own process for developing such a supplemental determination, we have set out a process for how the Commission will implement this supplemental determination, and we strongly encourage DWR to promptly submit a supplemental determination with the additional information we identify. This approach will result in a more accurate and equitable allocation of DWR's 2003 revenue requirement, and a likely reduction in the total amount of DWR's 2003 revenue requirement, with a corresponding decrease in the rates needed to be paid by consumers..

The Commission acknowledges the hard work and cooperation of the participants and Commission staff in meeting this proceeding's tight deadlines.

Chronology of the Proceeding

- August 16, 2002 – DWR issued its Determination of Revenue Requirements For the Period January 1, 2003 Through December 31, 2003 With Reexamination and Redetermination For the Period January 17, 2001 Through December 31, 2002 (Determination).
- August 19, 2002 - DWR submitted its Determination to the Commission.[2]
- August 29, 2002 - Pre-Hearing Conference Statements were filed and served by the Commission's Office of Ratepayer Advocates (ORA), the Energy Producers and Users Coalition (EPUC),[3] and Modesto Irrigation District.
- September 4, 2002 – A Pre-Hearing Conference was held at the Commission.
- September 12, 2002 – A technical workshop was conducted by the staff of the Commission's Energy Division.
- September 13, 2002 – Notices of recommended allocation method were filed and served by PG&E, SDG&E, SCE, and ORA.
- September 23, 2002 – Opening testimony was served by PG&E, SDG&E, SCE, and ORA.

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[2] Under the terms of the Rate Agreement, this delivery triggers the 120-day clock for Commission action.

[3] Along with EPUC, the statement was also on behalf of Kimberly Clark Corporation and Goodrich Aerostructures Group.

- September 30, 2002 – Rebuttal testimony was served by PG&E, SDG&E, SCE, ORA, and The Utility Reform Network (TURN).
- October 2, 2002 - Supplemental testimony was served by PG&E and DWR.
- October 2-4, 2002 – Evidentiary hearings were held at the Commission.
- October 16, 2002 – Opening briefs were filed by PG&E, SDG&E, SCE, and ORA.
- October 23, 2002 – Reply briefs were filed by PG&E, SDG&E, SCE, ORA, and TURN.
- November 15, 2002 – Proposed Decision was issued.

The Issues

The issues addressed here are: 1) allocation of DWR's 2003 revenue requirement among the three utility service territories; 2) treatment of excess energy sales and revenues; 3) treatment of ancillary services; 4) modeling questions; 5) exclusion of costs for demand reduction efforts; and 6) ratemaking and remittance procedures. Pursuant to the oral ruling of Administrative Law Judge (ALJ) Allen, issues relating to the true-up of DWR's 2001-2002 revenue requirement have been deferred until actual data for 2002 is available.

Allocation of DWR's 2003 Revenue Requirement

The main issue in this proceeding is how to allocate DWR's 2003 revenue requirement among the customers of three major utilities. This is not a brand-new task; we have previously allocated DWR's revenue requirement, but not in the same context that we face today. Nevertheless, two of our recent decisions, D.02-02-052 and D.02-09-053, provide some guidance on this issue.

In D.02-02-052, we allocated DWR's revenue requirement for 2001 and 2002.[4] In that decision, we evaluated a number of competing proposals, and ultimately adopted an allocation method proposed by SCE. We summarized that method and its basis as follows:

> SCE characterizes the procurement costs of DWR fixed long term (90 days or longer) contracts as costs incurred to meet the joint net short position of all three utilities. Because these long-term contracts provided a benefit to the entire State of California by lowering electricity prices on the spot market, SCE proposes that such fixed contract costs be allocated pro rata based on each utility's net short position.
>
> For short-term purchases (less than 90 days), however, SCE proposes that supply costs be allocated between PG&E and southern California utility customers based on the separate zonal cost of supplies using Path 15 as a dividing point. (*Id.*, p.48.)

For 2003, however, DWR will not be making any short-term purchases. (*See*, Water Code section 80260.) Accordingly, we do not need to allocate the costs of short-term purchases for 2003, but we do need to again allocate the costs of the existing long-term contracts.

Subsequently, in D.02-09-053, we adopted a policy of allocating the variable costs of the existing DWR contracts to the three major utilities. As of January 1, 2003, the utilities will be placing those contracts into their resource portfolios to be scheduled and dispatched in a least-cost manner. This was done as part of the process of requiring the utilities to resume their procurement planning role. As we stated, "…the utilities will now perform all of the day-to-day scheduling, dispatch and administrative functions for the DWR

[4] Readers seeking detailed background to the present decision should refer to D.02-02-052. D.02-02-052 was modified by D.02-03-062 and clarified by D.02-09-045. For brevity, this decision will simply cite to D.02-02-052.

contracts allocated to their portfolios, just as they will perform those functions for their existing resources and new procurements. Legal title, financial reporting and responsibility for the payment of contract-related bills will remain with DWR." (D.02-09-053, p.5.)

While D.02-09-053 established the policy that the variable costs of each contract should follow contract allocation (*id.*, p.6), it left to this proceeding the determination of the proper allocation of the total DWR revenue requirement. As a practical matter, since we are not changing the allocation of variable costs from D.02-09-053, what remains to be allocated here are costs other than variable costs, which consist primarily of the fixed costs of the contracts and DWR's related administrative and general costs.

The contents of DWR's 2003 revenue requirement are shown in the following summary tables:

DWR's August 16th Determination of 2003 Power Charge Expenses

Power Costs	$4,119,902,243
Administrative and General Expenses	$28,400,000
Ancillary services	$170,454,426
Increase in Operating Fund Balance	$517,399,690
Total DWR Power Charge Expense	**$4,836,156,359**
Less: Revenue from Sales of Excess Power	($128,885,940)
Less: Interest Earnings on Fund Balances	($59,007,505)
Total Ratepayer Revenue Requirement	**$4,648,262,914**

Source: DWR August 16th Determination, Table A-1

The positions of a number of parties shifted during the course of this proceeding, as their understanding of other parties' positions (and their own positions) evolved. These migrations of position were likely exaggerated by the highly expedited schedule, as parties had a relatively short time to do discovery and analysis prior to testimony and hearings. While this movement has resulted in some increased alignment of positions, the four most active parties still presented four different allocation methodologies.

SCE

SCE has proposed that the allocation of fixed costs follow the methodology adopted in D.02-09-053 for allocation of variable costs. This approach, commonly referred to as "costs-follow-contracts," would result in the fixed costs of DWR contracts being allocated to the customers of the same utilities to which the variable costs of those contracts were allocated in D.02-09-053.

According to SCE, the advantage of this approach is its internal consistency, as it avoids the possibility of one utility receiving a large allocation of variable costs under one method and a large allocation of fixed costs under another method. In addition to avoiding a mix of different allocation methods, which SCE regards as potentially unfair, SCE argues that its proposal is unique in that it provides the only approach that does not require future proceedings to establish future year allocations. SCE argues in the alternative that if the Commission were to decide not to use the "costs-follow-contracts" approach, then the Commission should adopt ORA's recommended approach.

SCE's "costs-follow-contracts" proposal attempts to use the allocation of contracts adopted in D.02-09-053 to allocate fixed contract costs, but SCE has not established that doing so is appropriate. D.02-02-052 addressed fixed costs, and accordingly is the more directly applicable precedent than D.02-09-053, which focused on variable costs. SCE's proposal conflicts with D.02-02-052.[5] While we are not necessarily bound to follow D.02-02-052, SCE has not persuaded us that there is a good reason for departing from that decision.

In D.02-02-052 we stated:

> [W]e agree with the goal of allocating DWR costs in relation to the costs of providing service. We do not believe, however, that segregating disproportionately higher priced DWR power for allocation exclusively to northern California consumers is a proper or fair application of traditional cost-based ratemaking policies. (*Id.*, p.4.)
>
> One measure of cost causation in relation to the three separate utility service territories would be evidence that DWR had actually procured separate portfolios of supplies specifically targeted toward each respective utility's customers. If DWR had expressly procured a separate portfolio of supplies for each utility service territory, there would be a strong cause-and-effect relationship between location of supplies and specific utility service territory served. This, in fact, did not occur. (*Id.*, pp. 59-60.)

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[5] In addition, SCE's argument is not actually supported by D.02-09-053. That decision expressly rejected the same argument that Edison makes here, and left the issue open, to be decided in this proceeding. (*Id.*, p.38.)

We concluded that:

> DWR thus has not maintained separate portfolios to meet the net short positions of each utility. Any allocation of power purchased under the DWR contracts and spot market purchases for each respective service area by assuming distinctly separate sources of supply for each utility is not consistent with the way DWR constructed its portfolio of supplies, and would not necessarily result in any more logical or accurate cost causation than a statewide pro rata approach. (*Id.*, p. 60.)

Our allocation in D.02-02-052 recognized the primarily integrated nature of power procurement undertaken by DWR for California utility customers, but we also adjusted for utility-specific differences, where applicable. Utility-specific adjustments were determined to be appropriate only in the case of short-term purchases, which we allocated geographically. Short-term purchases are not present here, eliminating the need for corresponding utility-specific adjustments to the allocation methodology.

Since DWR signed contracts for a statewide need, allocating the fixed costs of contracts to utility service territories based upon geographic location does not match how or why those contracts were obtained. It would be arbitrary and unfair for one or more service territories to end up with a disproportionate number of high-priced contracts when DWR was not trying to balance costs among service territories.

TURN notes that SCE's approach has the "appeal of simplicity and finality." Nevertheless, TURN argues that while SCE's "costs-follow-contracts" approach may have potential as a long term or future methodology, it is too soon to adopt it, particularly while the contracts themselves are in the process of being renegotiated. (TURN Reply Brief, p. 5.)[6] As TURN points out, with the contracts in active renegotiation, we cannot know how the cost of each contract may change in the future, and we have no way to evaluate the ultimate fairness of this allocation approach. PG&E similarly believes that "costs-follow-contracts" may be appropriate after contract renegotiations are concluded, but not before. (Ex. 1, p. 1-8.)

PG&E

PG&E proposes that DWR's revenue requirement be allocated to each utility in proportion to each utility's 2003 net short, adjusted to add back load loss from direct access and departing load customers, resulting in what PG&E calls "pre-load migration net short." From that initial allocation, PG&E would then subtract the variable costs that have been allocated to each utility. The remainder for each utility is the fixed cost component that gets remitted to DWR. According to PG&E, this method best takes into account direct access and departing load, and also best reflects the cost drivers of DWR's original contracting activities.

Compared with SCE's proposal, PG&E's is more consistent with DWR's original procurement focus, which was the aggregate net short position of the three utilities. Nevertheless, the passage of time, and the corresponding changes in the electricity market, render PG&E's proposal less appropriate than it may have been a year ago. When the Commission was examining the allocation of DWR's revenue requirement for 2001 and 2002, DWR was buying power for each utility's net short via a mix of short-term and longer-term contract purchases. For 2003, DWR is out of the procurement business, and the energy delivered to

[6] The state is attempting to renegotiate the existing DWR contracts in order to reduce their cost. DWR's revenue requirement would be reduced to the extent the state is successful in this effort.

each utility's customers by long-term DWR contracts does not necessarily match that utility's net short.

These changes render PG&E's allocation unfair. As ORA points out:

> [A]llocation on the basis of net short can lead to double counting and the imposition of inequitable costs for its residual net short. For example, a utility allocated a share of contract energy that is smaller than its share of net short will end up paying for its residual net short twice, once as part of the DWR revenue requirement, and a second time in the open market as the utility resumes responsibility for procurement of its residual net short. (ORA Reply Brief, p.3, citing to SCE's Opening Brief.)

TURN also makes the same point – PG&E's proposal could result in customers essentially paying twice for the same energy.

SDG&E

SDG&E proposes a "postage stamp" allocation, with DWR contract costs allocated to each utility in proportion to the quantity of energy supplied by DWR to each utility. However, SDG&E does not subtract out the variable costs the way that PG&E does.[7] Instead, SDG&E allocates the fixed costs independently of the variable costs. According to SDG&E, variable costs have already been allocated in D.02-09-053, have no role in the allocation of fixed costs, and need not be considered here. SDG&E argues that its proposed allocation is the most consistent with D.02-02-052.

The initial part of SDG&E's approach, with its allocation by supplied energy, is relatively equitable. By pooling all of the costs, it reflects the fact that DWR purchases and contracts were intended to cover the *aggregate* net short position of the three utilities. SDG&E's approach is more consistent with DWR's

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[7] ORA, like PG&E, subtracts variable costs to come up with a residual amount of fixed costs.

actual practices than is SCE's approach, which disaggregates the costs to the customers of each utility. SDG&E keeps the costs and benefits more closely aligned than SCE or PG&E, because SDG&E starts with the costs aggregated (the way that DWR incurred them), and then allocates them on the basis of what the contracts will actually provide in 2003: energy. DWR is not providing for the utilities' net short. Supplied energy, as proposed by SDG&E, is the most appropriate criteria for allocating the fixed costs of the DWR contracts.

However, SDG&E's subsequent disregard of variable costs gives an unfair result, and is criticized by all other parties. ORA makes the basic point:

> SDG&E's direct allocation of fixed costs can unfairly burden a utility with a disproportionate share of variable costs. SDG&E's method leaves utilities sharing fixed costs, but not sharing variable costs. A utility with a disproportionally large share of variable costs ends up paying all of their own variable costs as well as a greater than proportionate share of others' fixed costs. (ORA Opening Brief, p. 8.)

PG&E provides a hypothetical example to illustrate the problem:

> Under the example there are two utilities, and two contracts. The two contracts are expected to have the same overall costs. One contract has all fixed costs, and is allocated to one of the utilities. The other contract has all variable costs, and is allocated to the other utility…[T]he only distinction between the circumstances the two utilities face is that one has been allocated a contract that is all variable costs, while the other has been allocated a contract that is all fixed costs…The example illustrates that under SDG&E's approach the utility to which the variable cost contract has been allocated would bear all of the variable costs, plus half of the fixed costs, resulting in an overall burden for it of three-quarters of the costs. The other utility would bear only half of the fixed costs, resulting in

> an overall burden for it of one-quarter of the costs. (PG&E Opening Brief, pp. 13-14.)

SCE and TURN agree with ORA and PG&E that SDG&E's proposal to ignore variable costs is unfair.

ORA

ORA's proposal for allocation is also a "postage stamp" allocation. ORA's proposal starts out somewhat similarly to SDG&E, with a pro-rata allocation of the DWR revenue requirement based on each utility's share of the total amount of DWR delivered energy. ORA then departs from SDG&E by subtracting out the variable costs that have been allocated to each utility, resulting in a residual (fixed cost) revenue requirement.

According to ORA, the advantages of this method are that all utility bundled customers would be charged the same rate, and the allocation derived is the fairest, because it most accurately associates energy costs with the energy that the utility customers are actually getting from DWR's contracts. (ORA Opening Brief, pp. 3-4.)

While it is not clear that all bundled customers would actually be charged the same "rate" for DWR energy, ORA's proposal does treat all bundled customers equitably. ORA's overall approach is in fact the fairest of those proposed. Like SDG&E's proposal, ORA's proposal allocates costs in a way that corresponds to the benefits received (energy), and spreads the pain of those DWR contracts that are particularly expensive. ORA's proposal to distribute the costs of DWR contracts statewide among all ratepayers is more equitable and less arbitrary than the proposals of SCE and PG&E. Furthermore, by subtracting out the variable costs that we allocated in D.02-09-053, ORA's proposal avoids the problems caused by SDG&E's proposal to allocate fixed costs independently from variable costs.

An integral part of ORA's proposal is its recommendation that the Commission apply what ORA calls a "pre-Direct Access metric." ORA argues that the Commission should adjust the allocation of DWR's revenue requirement to take into consideration direct access and departing load customers subject to the Cost Responsibility Surcharge (CRS) set in R.02-01-011. In its Reply Brief, ORA acknowledges that this adjustment requires the results of a "Direct Access-In" modeling run from DWR's consultant, which had not yet been performed. ORA anticipated that such a modeling run would be completed well prior to the issuance of a Proposed Decision in this proceeding, and accordingly could be incorporated here. (ORA Reply Brief, p. 4, fn. 2.) Unfortunately, that did not happen, and the modeling run could not be completed in time to be utilized in this proceeding.

ORA's proposed adjustment received broad support. In addition to TURN, even parties who proposed different allocation methodologies did not quarrel with ORA's proposed adjustment. PG&E generally agrees with ORA that the allocation of DWR's revenue requirement should take into account direct access migration, and that the allocation should be consistent with the treatment of direct access and departing load in the CRS proceeding. (PG&E Reply Brief, p.4.) While SCE indicates some reservations (due to its questioning of certain direct access and departing load data), it endorses ORA's allocation proposal - including direct access and departing load adjustments - as the next-best alternative to its own proposal. (SCE Opening Brief, p.9.)

The direct access adjustment proposed by ORA is appropriate.[8] ORA's proposed departing load adjustment may also be appropriate, but it is not clear

[8] As recommended by SDG&E, continuous direct access load should not be included in this calculation. Consistent with D.02-11-022, the appropriate adjustment should reflect

when the information necessary to perform that adjustment will be available, as resolution of that issue has been deferred in the CRS proceeding.

Nevertheless, despite its merits, we are unable to incorporate the direct access adjustment at this time, as the evidentiary record in this proceeding does not provide adequate support for that adjustment. Accordingly, for the time being we are adopting ORA's proposal without the direct access adjustments. As soon as we are able to incorporate the appropriate modeling runs, we will make the necessary adjustments to reflect direct access. DWR should incorporate a "Direct-Access-In" modeling run into any supplemental determination it submits, so that we can make the adjustments described above.

We do need to make several minor modifications to ORA's methodology. TURN, which supports ORA's approach,[9] suggests two minor modifications. First, TURN argues that:

> [T]he revenues associated with off-system sales of DWR power should **not** be "pooled" and then allocated among the three utilities. Rather, these revenues should *directly offset* the revenue requirement of the dispatching utility. Otherwise, the incentive for economic dispatch would be seriously distorted. (TURN Reply Brief, p. 3, emphasis in original.)

The three utilities concur on this point, and we also agree.[10] Pooling would reduce the incentive for a utility to maximize the revenues from its sales of surplus energy. As discussed further below, revenues from sales of surplus

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that portion of direct access load that is subject to the DA CRS. PG&E errs by including continuous direct access load in its calculations.

[9] In testimony, TURN supported PG&E's proposal. In its Reply Brief, TURN changed its position to support ORA's proposal, but only if it incorporates the direct access adjustment described above.

[10] It does not appear that ORA is advocating pooling of revenues, but ORA's calculations reflect a pooled approach.

energy should be credited to the portion of the revenue requirement allocated to the customers of the utility making the sale.

TURN also recommends that instead of using the numbers for "DWR Delivered Energy" (sometimes referred to as retail energy), as proposed by ORA, it would be more appropriate to use the numbers for "DWR Supplied Energy" (sometimes referred to as wholesale energy). The basic difference between these two is that Delivered Energy has line losses subtracted out, while Supplied Energy reflects total DWR supplies prior to the subtraction of line losses. TURN's recommendation (which is similar to SDG&E's position on this point) results in the allocation of the revenue requirements better reflecting the differing line losses of the utilities, because DWR does not need to send as much energy to the customers of those utilities with lower line losses. To allocate DWR's revenue requirement on the basis of the amount of energy *received* by each utility's customer would result in customers of utilities with low line losses paying for the energy lost by the systems of utilities with larger line losses. Accordingly, we will modify ORA's proposal as recommended by TURN, and use the amount of energy *sent* to each utility service territory, rather than the amount of energy received, as the basis for allocating DWR's revenue requirement.

In addition to TURN's recommendations, PG&E points out that ORA erroneously treats tolling charges associated with DWR must-take contracts as a variable cost. (PG&E Reply Brief, p. 7.) As defined by D.02-09-053, tolling charges are sunk or unavoidable if those costs cannot be avoided by dispatch decision. DWR and the other utilities concur with PG&E that tolling contracts associated with must-take contracts should be considered a fixed cost, as their costs are not avoidable by dispatch decision. To apply ORA's allocation method in a manner that is consistent with D.02-09-053, we will treat tolling charges associated with must take contracts as fixed costs, not variable costs.

Our adopted interim methodology for the allocation of costs gives the results shown on the following table, which also shows how those results compare with the results of the other proposed methodologies:

Table A: Proposed and Interim Adopted Allocations

	Allocations to IOU Customers						
	PG&E		**SCE**		**SDG&E**		**Total**
PG&E Proposal	$1,846,000,000	41%	$1,824,000,000	41%	$808,000,000	18%	$4,478,000,000
SCE Proposal	$2,198,000,000	48%	$1,708,000,000	37%	$664,000,000	15%	$4,570,000,000
SDG&E Proposal	$1,995,000,000	44%	$1,890,000,000	42%	$690,000,000	15%	$4,575,000,000
ORA Proposal	$2,042,000,000	45%	$1,764,000,000	39%	$752,000,000	17%	$4,559,000,000
ORA*	$1,965,158,417	44%	$1,879,525,727	42%	$643,087,606	14%	$4,487,771,749

*As modified and adopted in this decision.

Note: Proposed allocations are shown as presented by the parties in the "Contract Cost Allocation Comparison Exhibit". In addition, due to rounding, sums may not equal totals.

The following table provides more detailed information on the adopted allocation:

TABLE B: Detailed Summary of Interim Adopted Allocation

	PG&E	SCE	SDG&E	Total
Ancillary Services	$61,753,088	$59,566,675	$20,144,663	$141,454,426
Variable Contract Costs	$85,661,819	$65,501,750	$68,722,250	$219,885,819
Fixed Contract Costs	$1,712,915,242	$1,669,104,118	$517,997,064	$3,900,016,423
Administrative and General Expenses	$12,398,253	$11,957,276	$4,044,472	$28,400,000
Operating Reserves	$134,351,926	$129,573,341	$43,827,352	$307,752,619
Total DWR Expenses	$2,007,080,328	$1,935,703,160	$654,735,801	$4,597,509,287

Less:				
DWR Surplus Sales Revenue	$(9,142,922)	$(25,336,197)	$(1,004,163)	$(35,483,282)
Interest Earnings	$(25,760,209)	$(24,843,979)	$(8,403,317)	$(59,007,505)
DWR Revenue from Ratepayers	$1,984,837,384	$1,897,722,878	$649,458,239	$4,532,018,501

In order to have consistent assumptions and inputs, neither table adjusts for direct access (*i.e.*, they do not incorporate a "Direct Access-In" modeling run), and both tables reflect the use of the modeling run known as PROSYM 36.[11] For additional detail on our adopted methodology, please refer to Appendix A.

Excess Energy Sales and Revenues

Treatment of revenues from sales of excess energy is an area that remains very much in flux, despite our best efforts to pin it down. To the extent details are available, they are set forth in Appendix A. Otherwise, we are primarily adopting general principles to provide guidance as this issue is subject to further refinement by the Commission, utilities, and DWR.

In D.02-09-053, we addressed the treatment of revenues attributable to excess energy sales:

> Sales revenues should be accounted for based on the composite of resources that each utility dispatches from its portfolio, rather than the timing with which specific resources were acquired. Accordingly, we will prorate sales revenues between the utility's revenue requirements and DWR's

[11] For Table A (and for our own analysis), it was necessary to use one consistent model run to properly compare the proposals. The parties did not all use the same modeling run, with some using PROSYM 36, while others used PROSYM 37. For the reasons described below in the section titled "Modeling Issues," we chose to use PROSYM 36.

> revenue requirements based on the relative quantities dispatched from utility generating assets (including contracts and market purchases in the future) and the DWR contracts. (*Id.*, pp. 42-43.)

We further specified, in some detail:

> Given these circumstances, we believe that the pro rata approach is the most equitable way to determine the relative amounts of retail and surplus sales revenues between DWR and the utilities. However, based on DWR's comments, we clarify that this approach involves the following steps: [fn. omitted] (1) calculating the amount of surplus sales based on the excess of total utility portfolio resources (including DWR contracts allocated today) relative to loads, (2) allocating those sales revenues between DWR and the utilities based on the relative quantities dispatched from utility resources and the DWR contracts, and (3) calculating the revenue from retail customers using the difference between dispatched quantities and the surplus sales quantities calculated under (2). We direct the utilities to work with DWR to develop specific accounting and reporting procedures consistent with the pro rata approach we adopt today. These procedures should be developed in DWR's 2003 revenue requirements proceeding. (*Id.*, pp. 44-45.)

Today we continue to flesh out the approach adopted in D.02-09-053. The utilities were granted an extension of time to submit their procedures for implementing that decision, and filed them on October 8, 2002, after the close of evidentiary hearings in this proceeding. Even with the extension, the utilities' proposed procedures are still very much works-in-progress, and do not reflect final agreement between the utilities and DWR. This reinforces the constantly moving target nature of this proceeding, but our task is made somewhat easier by the fact that SDG&E, SCE, ORA, and TURN largely agree on the general principles to be applied.[12]

As we discussed above, revenues associated with surplus sales of DWR power should not be pooled, but instead should offset the portion of the DWR revenue requirement allocated to the customers of the dispatching utility. This approach is consistent with the policy of D.02-09-053, as it maximizes the incentives for utilities to make sales of surplus energy.

As SDG&E puts it:

> SDG&E recommends that revenues from sales of excess DWR energy be apportioned to the customers of the utility making the sales, and not to all utilities' customers as a pool. D.02-09-053 declined to address this issue, instead deferring it to this proceeding. SDG&E further proposes that revenues from sales of surplus DWR energy will be credited to the DWR revenue requirement allocated to the utility's customers. By apportioning the revenues in this manner, the utility making the sale will know that its action will directly benefit its customers. If revenues from those sales were pooled, there would be little incentive for any one utility in making those sales because the results would be spread among the customers of all utilities. Keeping sales revenue with the utility making the sale is also consistent with D.02-09-053's requirement that variable costs follow contracts. The revenue from these surplus sales can vary depending, at least to an extent, on the decisions of the utility. Market conditions will be the primary factor affecting the revenue from these sales. The Commission should therefore adopt SDG&E's proposal and order that the revenue from these sales be apportioned to the customers of the utility making the sales. (SDG&E Opening Brief, pp.5-6.)

SCE and SDG&E each propose certain adjustments to this general principle, with each claiming their proposal will render the outcome more

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[12] PG&E's position on this issue is not entirely clear.

closely congruent with the complexities of reality. SCE proposes to exclude what it calls "resource specific sales," such as off-system sales from resources located outside the ISO control area. SDG&E, instead of applying the ratio of total URG to DWR energy, uses only must-take energy in its calculation.[13] These proposed adjustments add needless complexity and opportunities for gaming, and are inconsistent with our clear statement in D.02-09-053 that surplus sales calculations are to be based on *total* utility portfolio resources. (*Id.*, p.7.)

Our task is complicated by the fact that DWR's August 16 Determination was prepared prior to the issuance of D.02-09-053, and accordingly does not reflect our adopted treatment of revenues from sales of surplus energy. While DWR subtracts anticipated surplus sales revenues from its revenue requirement, DWR's surplus sales revenues are likely to be significantly different than those assumed in the August 16 Determination.

The sales protocol adopted in D.02-09-053 will cause DWR surplus sales to decrease, with a corresponding increase in utility surplus sales. Likewise, DWR retail sales will increase, with a corresponding decrease in utility retail sales. In essence, the revenues collected by DWR would be based on a power charge calculated using retail sales numbers from its August 16 Determination (rather than from the protocol set forth in D.02-09-053), but applied to a much larger retail sales volume. This will result in utility undercollection and DWR overcollection relative to the figures in DWR's August 16 Determination.

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13 While SDG&E maintains that its use of must-take energy best emulates the typical surplus sale hour scenario, SDG&E indicates (in response to TURN's Rebuttal Testimony) that it is willing to eliminate this aspect of its proposal, and notes that the outcome of the two calculation approaches is nearly identical. (SDG&E Opening Brief, p.6.)

SCE, SDG&E, TURN, and ORA agree that the revised allocation protocols for sales adopted in D.02-09-053 will require an adjustment to DWR figures to reflect greater retail sales and less surplus sales revenues by DWR. DWR should incorporate an appropriate adjustment in its supplemental determination.

SCE proposes establishing utility-specific balancing accounts that would capture each utility's allocation of DWR costs and each utility's energy sales revenues paid to DWR. This tracking of the costs and revenues related to the DWR contracts allocated to each utility would be for the purpose of future allocation true-ups. (SCE Opening Brief, pp.10-11.) The proper scope and nature of allocation true-ups has not been determined. As described below, all issues relating to the true-up of DWR's 2001-2002 revenue requirement have been deferred until 2003. It would be premature to approve balancing accounts for 2003 before determining the propriety of recovery for 2001 and 2002. SCE's proposal to establish utility-specific balancing accounts is not approved here, but SCE may raise the issue again in the portion of this proceeding addressing the true-up of DWR's revenue requirement for 2001-2002.

The utilities are in the process of negotiating servicing agreements with DWR, and those negotiations provide a reasonable forum for the resolution of the administrative details needed to implement the general policies we adopt on this issue. DWR should incorporate in its supplemental determination the updated terms of the servicing agreements, along with the protocols adopted in D.02-09-053.

Ancillary Services

DWR asserts that it continues to have authority to obtain and pay for ancillary services, and estimates its 2003 cost for doing so at approximately $170 million. In its August 16 Determination, DWR notes that: "If the

Department is not required to pay for ancillary services costs in 2003, the total revenue requirement would decrease by $170 million." (Determination, p.31.) There is some consensus, some dispute, and possibly some confusion amongst the parties on this issue.

SDG&E proposes in its testimony that the $170 million be removed from DWR's revenue requirement. According to SDG&E, each utility should be responsible for the cost of providing ancillary services for its bundled load. In addition to administrative simplicity, SDG&E argues that each IOU should decide for itself how to provide ancillary services, and notes that DWR has not entered into contracts for ancillary services, but rather has relied upon the ISO to provide them.

Conceptually, PG&E agrees with SDG&E that the utilities should be responsible for their respective ancillary service obligations. However, PG&E believes it is premature to remove ancillary services costs from DWR's 2003 revenue requirement before PG&E and SCE are restored to creditworthiness. PG&E would not object to SDG&E's proposal if it were to be applied only to SDG&E, but does object to applying SDG&E's proposal to PG&E. Accordingly, PG&E would leave the $170 million (or at least some portion of that amount) in DWR's revenue requirement to provide creditworthy backing to the utilities, but each utility would be responsible for the costs DWR incurs on behalf of its customers.[14] PG&E recommends that DWR's revenue requirement for ancillary services be allocated separately, and not subject to the allocation methodology otherwise adopted here.

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[14] SDG&E argues that PG&E could utilize other forms of credit backing instead of DWR's revenue requirement.

In its Opening Brief, SCE states that it agrees with SDG&E, but its description of what it proposes sounds more like PG&E's position. In its Reply Brief, SCE essentially states that this issue should be left to the individual utilities to address with DWR or the ISO.

TURN agrees with SDG&E and PG&E that ancillary services costs should be allocated to the utility for which those ancillary services are purchased. TURN is neutral between the two proposals, and sees no direct impact to ratepayers from choosing one over the other, as either proposal would result in payment coming from the utility that uses the services. ORA does not appear to distinguish between the PG&E and SDG&E proposals.

There appears to be consensus among the parties on one aspect of this issue: each utility should be responsible for the cost of ancillary services provided to its customers, regardless of whether those ancillary services are provided by the utility or by DWR. In theory, we agree with all parties that a general allocation methodology should not be applied to the cost of ancillary services, but rather each utility should pay for ancillary services provided to its customers; if DWR provides those services, then the utility customers receiving those services should pay DWR.

Unfortunately, this is an area where the gap between theory and practice is larger in practice than it is in theory. In response to the parties, DWR asserts that the estimated costs of ancillary services should remain in its 2003 revenue requirement, and that it is reasonable to continue to include them in the revenue requirement. (DWR Memorandum, dated October 23, 2002.) DWR's insistence at keeping the $170 million in forecast ancillary services costs in its revenue requirement, coupled with the terms of the Rate Agreement, leave us no choice but to leave those dollars in place, to be passed on to the ratepayers. Even though we agree with SDG&E that there is no need for the $170 million to remain in the DWR revenue requirement, we cannot remove them.

We urge DWR to reconsider its demand for $170 million in ratepayer money for ancillary services. DWR's supplemental determination should look closely at the assumptions used in its forecast of costs for ancillary services. All utilities should provide DWR with current data, assumptions, and forecasts relating to DWR's potential ancillary services costs, so DWR can consider that information in preparing its supplemental determination.

There are significant real-world differences between the utilities on this issue (including creditworthiness, self-provision of ancillary services, invoicing, and other administrative issues). This renders a generalized allocation approach less appropriate, but DWR's simplistic approach to ancillary services leaves that as our only choice.

DWR's estimate of ancillary services costs did not distinguish between the utilities. DWR estimated a cost of ancillary services based upon volumes of delivered energy, and DWR's total estimated cost for ancillary services did not take into consideration differences such as the relative creditworthiness of SDG&E and PG&E.

Were our allocation to take into consideration differences between the utilities, such as the actual amount of ancillary services provided by DWR, it would result in a reduction of the costs of ancillary services for some utilities, such as SDG&E. But DWR's refusal to reduce the total dollar amount of its revenue requirement for ancillary services would render the resulting allocation inequitable. Under DWR's approach, the pie remains the same size even if a large slice of it is removed.

This means that we cannot allocate the costs of ancillary services in the manner recommended by the parties, which we prefer. Instead, we can only apply a more generalized allocation methodology. Accordingly, we will allocate DWR's $170 million for ancillary services using the same approach we have adopted for allocating DWR's fixed costs. We will revisit this allocation approach during our evaluation of DWR's supplemental determination, in the hopes of implementing an allocation that results in each utility being responsible for the cost of providing ancillary services for its bundled load.

Modeling Issues

DWR's August 16 Determination was based upon a modeling run referred to as PROSYM 36. Subsequently, DWR performed another modeling run, PROSYM 37. The results of PROSYM 37 were presented in DWR's Exhibit 12, which was distributed on October 2, and Exhibit 12-A, which was distributed on October 4. PROSYM 37 incorporates corrections suggested by PG&E, as well as post-processing adjustments that factor in some impacts of D.02-09-053. DWR did not modify the revenue requirement in its August 16 Determination as a result of PROSYM 37, but rather provided the new run for the Commission's use in allocating the revenue requirement among the utilities.

PG&E and ORA support the use of PROSYM 37, on the grounds that it contains the most current and accurate information.

SDG&E and SCE argue that PROSYM 37 should not be used here. While not specifically identifying problems with PROSYM 37, they argue that its presentation during evidentiary hearings was too late in the proceeding for parties to adequately evaluate it, perform discovery, or prepare for cross examination. Accordingly, SDG&E and SCE argue that use of PROSYM 37 in this proceeding would violate due process, Public Utilities Code section 1822, and Rule 74.5(b) of the Commission's Rules of Practice and Procedure. They further argue that it is not appropriate to use PROSYM 37 for allocation of the revenue requirement because it does not correspond to the model used by DWR in deriving its revenue requirement, resulting in a potentially unfair mismatch.

While we generally agree with PG&E and ORA that we should be using the most accurate and up-to-date information and assumptions, SDG&E and SCE raise a valid concern. If we were to use PROSYM 37, it could result in a significant change in the allocation of the DWR revenue requirement as compared with PROSYM 36, presumably to the detriment of SDG&E and SCE. PROSYM runs are complex and highly technical, and PROSYM 37 was presented too late in this proceeding for parties to meaningfully evaluate or address its contents, methodology, or effects. Based on the facts before us, it would be inconsistent with due process to base our allocation upon PROSYM 37.[15] We are also concerned by the potential unfairness of basing our allocation of DWR's revenue requirement on one model, while the revenue requirement itself is based on another model.

Accordingly, for purposes of this decision, we are uniformly using PROSYM 36. Nevertheless, we do have a duty to ensure that our allocation is as consistent as possible with reality and with DWR's actual revenue requirement. The modifications and adjustments made in PROSYM 37 may also result in a somewhat lower revenue requirement than produced by PROSYM 36.[16] While the potential for a reduced revenue requirement is very attractive, PROSYM 37 by itself does not provide an adequate basis for a new revenue requirement.

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[15] We do not reach the arguments based upon the Public Utilities Code and the Commission's Rules of Practice and Procedure. The due process ruling reached here is narrow, and based upon the specific facts of this case.

[16] DWR has not sought a reduced revenue requirement as a result of PROSYM 37.

Among other things, DWR has its own processes and requirements for the preparation and presentation of a new revenue requirement. However, SDG&E and SCE (and any others) should be given a reasonable opportunity to provide suggestions to DWR, with everyone being subject to the same deadline. DWR can then evaluate those suggestions, and incorporate those it finds to be appropriate in its supplemental determination.

Demand Reduction Costs

DWR's revenue requirement includes $29 million in regards to a proposed demand response program intended to decrease customer demand during hours of high demand and short supply. These costs are included in DWR's forecast of ancillary service costs. We remove these costs from DWR's proposed revenue requirement. AB 1X, which authorized DWR to purchase energy and charge the costs of DWR purchased energy to utility customers did not give DWR the authority to incur costs for demand reduction programs, nor charge such costs to ratepayers. Since the $29 million in costs for demand reduction programs in DWR's current request is not within DWR's statutory authority to include in charges to consumers, we must remove those costs from the revenue requirement adopted today. We note that costs for demand reduction programs were not included in the prior DWR revenue requirement approved by the Commission in D. 02- 02052. The decision to remove these costs is not a reflection on the effectiveness or merit of such programs, which the Commission is not addressing in this proceeding.

Ratemaking and Remittance Issues

In D.02-03-062 we directed PG&E, SCE, and SDG&E to begin disbursement of proceeds to DWR, as required by their respective servicing agreements or Commission order, using the respective charges in cents-per-kilowatt-hour (kWh) of 9.211 for PG&E, 9.706 for SCE and 7.742 for SDG&E. These charges will change as a result of today's order, as described below. While the parties have made a number of proposed changes to current remittance practices, we adopt only those changes necessitated by policies we have adopted in related proceedings since D.02-02-052.

PG&E recommends that each utility remit variable costs under the contracts allocated to it to DWR on an actual incurred cost basis, in order to put D.02-09-053's variable-costs-follow-contracts requirement into effect. Second, each utility would remit ancillary services costs incurred on behalf of that utility, as well as DWR's share of surplus sales revenue, on an actual incurred cost basis. Finally, PG&E proposes that each utility remit the remaining fixed component of DWR's revenue requirement to DWR on a monthly basis. Under PG&E's approach, the amount to be remitted for the month would be remitted at the end of the following month in order to smooth the transition from the remittance methodology used for DWR's 2001-2002 revenue requirement to the remittance methodology used for the 2003 revenue requirement.

SCE proposes to continue its current process of remitting funds to DWR. SCE's practice is to transmit funds received from customers to DWR on a daily basis. SCE expresses concern that PG&E's proposal is not consistent with provisions of ABX1-1 because it results in commingling of payments by retail customers for DWR and URG power. SCE recommends that, in view of the uncertainties involved in PG&E's proposal, the Commission should allow SCE and DWR to determine their own appropriate remittance practices.

SDG&E recommends that the DWR remittance rate should be based on the forecast of DWR deliveries to bundled customers as a result of the pro rata allocation in D.02-09-053, and not on the deliveries utilized in the tables in

DWR's August 16 Determination. According to SDG&E, the pro rata allocation will have the effect of increasing DWR deliveries to retail customers, so use of the forecast deliveries in DWR's August 16 Determination to set power charges would result in an overcollection by DWR.

ORA proposes that remittances to DWR consist of actual variable costs, plus the forecast residual revenue requirement, as adjusted for actual Direct Access Cost Responsibility Surcharge remittances. ORA asserts that its proposal is probably the easiest to implement since it results in a uniform "postage stamp" energy rate for all three utilities

TURN observes that PG&E has proposed some very significant changes to the current remittance procedures for transferring money to DWR, and that SCE has identified some potentially serious problems with PG&E's proposed approach. TURN urges the Commission not to change the remittance procedures unless DWR has explicitly agreed to any such changes.

In fact, DWR has not agreed to such changes. DWR agrees with SCE, and concurs in SCE's criticism of PG&E's proposal. We reject PG&E's proposal, namely that each utility remit to DWR, on a monthly basis, the fixed component of DWR's power cost revenue requirement after subtracting DWR's estimate of the variable costs of the contracts allocated to the utility. Absent agreement from DWR, and except as ordered here, utilities should maintain their current processes for remitting funds to DWR.

The changes to current remittance practices that we adopt today are limited to those necessitated by policies we have adopted in related proceedings subsequent to D.02-02-052.

First, we agree that each utility should remit DWR's share of surplus sales revenue directly to DWR on an actual receipts basis.

Second, although we agree that ideally each utility should remit to DWR the variable costs of the contracts allocated to it on an actual incurred-cost basis, we are bound by the Rate Agreement to include these costs in the calculation of power charges that we adopt for each utility's customers.

Third, while we would prefer that each utility remit ancillary services costs incurred on behalf of that utility directly to DWR on an actual incurred-cost basis, we cannot do so, as previously described. We again are bound by the Rate Agreement to include these costs in the revenue requirement that is collected through the power charge.

Fourth, the revenue requirement that is collected from bundled ratepayers should be reduced by actual Direct Access Cost Responsibility Surcharge remittances, as ordered in D.02-11-022. However, since we do not have accurate information on the record about the volume of direct access sales that will be subject to the surcharge, we do not include any estimate of the impact of this adjustment in the charges we calculate today.

Finally, in order to calculate the new total power charges that will collect the total ratepayer revenue requirement, we use DWR retail sales that have been adjusted to reflect the protocol for surplus sales that we adopted in D.02-09-053. As a result of this adjustment, retail sales are significantly higher than the level assumed in DWR's August 16 Determination. Accordingly, DWR's cash flows will not require the increase of $517 million in its Operating Fund balance anticipated in the August 16 Determination. This adjustment should not affect the level of funds that DWR has available when needed.

To the extent necessary, the respective servicing agreements or Commission order for each utility should be modified to be consistent with the approaches described above.

Table C summarizes the remittance procedures described above, and illustrates how DWR will be paid for the entirety of its revenue requirement.

Table C

Calculation of Adopted IOU Power Charges—Corrected November 22, 2002

2003 DWR Expenses	
Power Costs	$4,119,902,243
Administrative and General Expenses	$28,400,000
Ancillary Services	$141,454,426
Increase in Operating Account Balance	$292,505,867
Total DWR Expenses	**$4,582,262,536**
Revenues Other Than Ratepayer Remittances	
Revenues from Sale of Excess DWR Power	$35,483,282
Interest Earnings	$59,007,505
Total Revenues Before Ratepayer Remittances	**$94,490,787**
DWR Revenue Required from Ratepayers	**$4,487,771,749**

Cost Allocation Summary	**PG&E**	**SCE**	**SDG&E**	**Total**
DWR Revenue Required from Ratepayers				**$4,487,771,749**
Allocation of Total Revenue Requirement	$1,965,158,417	$1,879,525,727	$643,087,606	$4,487,771,749
less: Direct Access CRS Revenues	$0	$0	$0	$0
less: Revenue to maintain Operating Account above $1 billion	$127,695,832	$123,153,989	$41,656,047	$292,505,867
less: Allocation of Ancillary Services	$61,753,088	$59,556,675	$20,144,663	$141,454,426
less: Allocation of Variable Costs	$85,661,819	$65,501,750	$68,722,250	$219,885,819
Equals: Residual Fixed Costs	$1,690,047,678	$1,631,313,313	$512,564,645	$3,833,925,636
2003 DWR Delivered Energy (kWh)	19,205,963,516	18,459,409,403	6,398,534,999	44,063,907,918
Components of IOU Power Charge ($/kWh)				
1. Ancillary Services Cost Component	$0.00322	$0.00323	$0.00315	$0.00321
2. Variable Power Cost Component	$0.00446	$0.00355	$0.01074	$0.00499
3. Fixed Power Cost Component	$0.08800	$0.08837	$0.08011	$0.08701
4. Charge Component to Fund Operating Account	$0.00902	$0.00902	$0.00902	$0.00902
Total IOU Power Charge ($/kWh)	**$0.10469**	**$0.10417**	**$0.10302**	**$0.10423**
Total Ratepayer Revenues	**$1,965,158,417**	**$1,879,525,727**	**$643,087,606**	**$4,487,771,749**

Note: multiplying the Power Charges shown above by delivered energy will not result in Ratepayer Revenues shown above, because DWR assumes a 45 day lag between delivery of energy and receipt of cash

Direct Access Cost Responsibility Surcharge

In D.02-11-022, we adopted policies and procedures for determining the DA CRS, but also directed that a compliance workshop be convened to determine the actual numerical values and to implement actual utility compliance tariff filings. D.02-11-022 also called for the implementation process for the DA CRS to be integrated and coordinated with the implementation of the DWR revenue requirement in this proceeding. A Joint Ruling issued in this proceeding and in R.02-01-011 on December 10, 2002 addressed the process for this coordination.[17]

The Ruling ruled, among other things, that:

1. In the interests of expediting the start of recovery of Direct Access Cost Responsibility Surcharge (DA CRS) revenues, parties are placed on notice that in finalizing the Commission decision on the 2003 the Department of Water Resources (DWR) revenue requirement, language may be added directing each of the utilities to file advice letter compliance tariffs to implement the 2.7 cents/kWh DA CRS on an interim basis to become effective on January 1, 2003.
2. The language proposed to be added would provide for the DA CRS compliance tariffs to take effect as of January 1, 2003, upon review by the Commission's Energy Division, absent any filed protests or further action by the Commission.

Parties were given the opportunity to file comments on the ruling. Comments were received from SCE, PG&E, and SDG&E. DWR provided a comment memorandum after the deadline for submission of comments. All three utilities and DWR support the addition of the proposed language.

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[17] *Administrative Law Judges' Joint Ruling Regarding the Process to Implement Direct Access Cost Responsibility Surcharges.* This Ruling contains additional background information on the DA CRS issue.

Some of the comments provided detailed recommendations for processes to address this issue further. While we appreciate the thought and effort that went into these comments, we will not address those processes here, but prefer that they be addressed in a separate ruling. Since the implementation of the tariffs is on an interim and provisional basis, any protests will not stay their effective date of January 1, 2003. Similarly, we will not resolve substantive issues raised for the first time in the comments, other than to note that for DA customers that have remained continuously on DA, and did not take bundled service on or after February 1, 2001, pursuant to D.02-11-022 the applicable DA CRS shall be limited to the Historic Procurement Charge (HPC), applicable to SCE customers only.

Consistent with the Joint Ruling, language is added to this decision directing each of the utilities to file advice letter compliance tariffs to implement the 2.7 cents/kWh DA CRS on an interim basis to become effective on January 1, 2003. A ruling addressing the schedule and process for the workshop and implementation of the resulting DA CRS will be issued shortly.

2001-2002 True Up

In response to recommendations from SDG&E and TURN, and with the agreement of DWR, ALJ Allen ruled that the issues relating to the true-up of DWR's 2001-2002 revenue requirement would be deferred until actual data for 2002 was available. (Transcript v.48, pp.6802-04.) This ruling is appropriate, and is consistent with D.02-02-052, with D.02-02-051, and with the Rate Agreement between the Commission and DWR.

In a separate letter/memorandum dated October 16, 2002, DWR states that actual data for the entire 2001-2002 period will be available in April, 2003. Parties were given the opportunity to recommend a process and schedule for the true-up phase in their briefs, to eliminate the burden of filing a separate pleading.

SDG&E states that it cannot at this time identify what specific issues may be presented, but provides a proposed schedule for the true-up process, with parties filing proposals and procedural recommendations within 21 days after DWR releases its recorded data for the 2001-2002 revenue requirement period, followed by workshops or hearings, as needed. SDG&E expresses hope that the true-up process will be relatively noncontroversial.

SCE argues that the scope of the true-up proceeding should consist of a true-up of DWR's total 2001-2002 forecast expenses to actual expenses, true-up of the allocation of those actual expenses to the utilities' customers, and a true-up of the previous allocation of "net borrowed proceeds" and what the utilities' customers actually pay to DWR. SCE believes its customers have overpaid DWR's prior revenue requirement, and accordingly recommends an extremely expedited schedule for the true-up phase, beginning (and ending) prior to the availability of actual 2002 data.

PG&E, on the other hand, argues that no re-allocation true-up of DWR's 2001-2002 revenue requirement is necessary or appropriate, and requests a Commission determination that no true-up will be made.[18] PG&E appears to be most concerned about the possibility of an inter-utility true-up of the sort desired by SCE. In the alternative, PG&E requests that any true-up be completed before the end of 2002.

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[18] However, PG&E's October 8, 2002 filing re surplus sales allocation states: "Differences between the forecast used to set the revenue requirement and the actual surplus sales revenue will be trued up in a future DWR Revenue Requirement Proceeding." (*Id.*, p. 3.)

The schedules proposed by SCE and PG&E are not realistic, would put undue burdens on both parties and the Commission, would require another subsequent true-up, are not an efficient use of resources, and constitute a collateral attack on ALJ Allen's ruling.

We will not determine here the specific details of how any true-up of DWR's 2001-2002 revenue requirement is to be done, other than to note that DWR will not be required to return funds already received from ratepayers.[19] All participants will be given an opportunity to express their positions in a separate true-up phase, consistent with ALJ Allen's ruling.[20] While SDG&E's proposed schedule is reasonable, we do not adopt it here, but leave to the ALJ and Assigned Commissioner the task of establishing a schedule and process for a true-up phase that incorporates actual data for DWR's 2001-2002 revenue requirement period.

Other Issues

PG&E recommends that the Commission retain the one-half cent per kWh "Catch-Up" surcharge originally adopted in D. 01-05-064 to partially offset DWR's requested increase in its revenue requirement. SCE similarly recommends that the Commission defer a potential rate increase by authorizing SCE to use the Catch-Up surcharge revenues to offset the increase in DWR's revenue requirement. (*See*, Resolution E-3776, issued June 6, 2002.) While these

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[19] In light of the provisions of the Indenture for DWR's bonds and the provisions of the Water Code under which DWR establishes its own revenue requirement, we do not believe that, as a general matter, we can order DWR to refund monies previously received. This does not prevent us from reducing DWR charges in the future to reflect past over-collections. Nor do we believe that we are barred from adjusting future allocations among service territories to reflect prior results.

[20] At that time PG&E may, if it wishes, renew its argument that no true-up should be done.

requests are facially similar, PG&E and SCE are in significantly different positions, and also differ significantly in the showings they have made on this issue.

In its testimony and in its Comments on the Proposed Decision, SCE describes the impact of DWR's 2003 revenue requirement, and specifically sets forth the impact of the portion of that revenue requirement allocated to SCE. According to SCE, that impact, when examined in the context of the settlement agreement in the filed rate doctrine litigation between SCE and the Commission, results in a retail rate increase to ensure that the surplus contribution to the Procurement Related Obligations Account (PROACT) is not affected. SCE states that it can defer a rate increase by using Catch-Up surcharge revenues to offset the increase in its portion of DWR's 2003 revenue requirement.[21]

We prefer to avoid a rate increase, and SCE has made a substantial showing how use of the Catch-Up Surcharge will avoid a rate increase. SCE's proposal is also consistent with D.02-11-026, which removed certain restrictions on the use of surcharge revenues. We accordingly grant SCE's request for use of the Catch-Up Surcharge revenues.[22]

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[21] The Catch-Up Surcharge revenues would not flow directly to DWR, but rather would be used to maintain the level of SCE's surplus. As SCE describes it: "Beginning in January 2003, on a monthly basis, SCE will determine through the operation of the Rate Change Tracking Account [fn. omitted] the actual amount of reduced Surplus being caused by increased procurement costs (both DWR and SCE-related). The Surplus impact calculated in the Rate Change Tracking Account will determine the amount of Catch-Up surcharge revenues to be transferred from the Catch-Up Surcharge Revenue Memorandum Account [fn. omitted] to the PROACT. The transfer from the Catch-up Surcharge Revenue Memorandum Account to the PROACT will ensure that the Surplus contribution to PROACT is not affected by the increased procurement costs."

[22] We do not otherwise modify our prior decisions regarding the Catch-Up surcharge here.

PG&E has also consistently requested similar authorization to use the revenues from the Catch-Up Surcharge to offset an anticipated increase in its portion of the DWR revenue requirement for 2003. (*See, e.g.* Exhibit 1, p.6-1.) PG&E has not, however, shown that it actually needs to use the Catch-Up Surcharge revenues to avoid a rate increase. PG&E provides no detailed analysis of the sort provided by SCE, and in fact provides no analysis at all. PG&E's request to use the Catch-Up Surcharge revenues is unsupported, and is denied.

PG&E recommends that the Commission make clear to DWR that the Commission expects DWR to act immediately to lower its revenue requirement should DWR's costs become significantly lower. (PG&E Opening Brief, pp.31-32.) TURN agrees with PG&E. (TURN Reply Brief, p.8.) While we would hope this would go without saying, it bears repeating: every dollar of DWR's revenue requirement is a dollar that must be paid by California ratepayers, so every dollar by which that revenue requirement can be reduced is another dollar that can remain in the pocket of a California ratepayer. We encourage DWR to do all it can to reduce its costs, and to promptly lower its revenue requirement accordingly. We believe that DWR's supplemental determination may reflect a reduced revenue requirement, and we expect that DWR will make every effort to further minimize its revenue requirement.

We note that an update may have a significant downward impact on DWR's revenue requirement, and the resulting rates charged to customers in California. At issue are over $170 million in potentially duplicative ancillary service costs being; over a billion of cash reserves that should be unnecessary as the utilities resume the responsibility for procuring energy to meet their net short positions in 2003, and other matters. By appropriately updating their revenue requirement in a timely manner, DWR can help us ensure that the burden on ratepayers and the economy of California to pay for expensive DWR power is minimized.

SDG&E argues that no part of any DWR revenue requirement pertaining to power contracts entered into by DWR between August 22, 2002 and January 1, 2003 (pursuant to D.02-08-071) be allocated to SDG&E. According to SDG&E, any such contracts would be for the sole benefit of the customers of SCE and PG&E, and SDG&E customers should not have to bear their costs. SDG&E acknowledges that DWR's revenue requirement does not currently contain any such costs, but SDG&E expects that DWR may incur costs as provided for in D.02-08-071, and it would be appropriate for ratemaking mechanisms to be put in place in anticipation.

In D.02-08-071, we authorized PG&E and SCE to enter into power contracts using the credit backing of DWR. We did not extend that authority to SDG&E, as we found that there was no need for DWR to "backstop" purchases by SDG&E. Since the contracts potentially at issue would be entered into by the individual utilities on behalf of their own customers (as opposed to the earlier contracts negotiated by DWR on behalf of the whole state) it is reasonable to assign the costs of those contracts to the customers of the utility that entered into them. Consistent with SDG&E's request, to the extent that DWR's revenue requirement includes costs associated with this category of contracts, those costs will be directly assigned to the customers of the utility that entered into any such contract or contracts.

Implementation

To reduce the potential for confusion and uncertainty, we will describe the implementation process for the adopted revenue requirement allocation and for

DWR's supplemental determination.[23] The charges established in this proceeding go into effect January 1, 2003, and will remain in effect until further order of the Commission.

A. Narrative Explanation of the Revenue Requirement Allocation

Definitions

1. Variable Costs: Variable costs, as defined in D.02-09-053, are those that can be avoided by dispatch decision. Specifically, variable costs are the energy payments associated with the dispatchable contracts assigned to the IOUs by D.02-09-053.
2. Residual Fixed Costs: Residual fixed cost are calculated by subtracting variable costs from the adjusted DWR revenue requirement. Residual fixed costs would include fixed contract costs, ancillary services, administrative and general expenses, and increases to operating account balances.

Revenue Requirement Adjustments

1. The revenues required from ratepayers in 2003 by DWR ($4.532 Million) is the sum of Fixed and Variable Contract costs, A&G Expenses, Ancillary Services, and Operating Reserves, minus Surplus Sales Revenue and Interest Earnings.

Allocation of 2003 DWR Revenue Requirement

1. Calculate each IOU's portion of DWR supplied energy.
   a. Determine amount of DWR supplied energy in each IOU resource portfolio.
   b. Adjust the amount of DWR supplied energy for each IOU by adding DWR's share of Pre-Direct Access migrated load to DWR supplied energy.
   c. Subtract DWR's portion of surplus energy from DWR's Pre-DA supplied energy.

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[23] Appendix A provides additional detail regarding the allocation methodology.

2. Allocate adjusted DWR Revenue Requirement ($4.532 million) to each IOU according to their share of DWR supplied energy.
   a. Calculate each IOU's DWR supplied energy allocation factor by dividing each IOU's portion of DWR supplied energy by the total of DWR supplied energy.
   b. Determine each IOU's share of the DWR Revenue Requirement by multiplying the adjusted DWR Revenue Requirement by each IOU's DWR supplied energy allocation factor.
   c. Calculate each IOU's residual fixed costs by subtracting variable costs, assigned by D.02-09-053, from each IOU's share of DWR Rev Req.

B. The DWR Supplemental Determination Process

There are four areas where a supplemental determination from DWR is necessary for us to optimally perform our allocation of DWR's 2003 revenue requirement. As described above, those areas are treatment of direct access migration, forecasted costs of ancillary services, opportunity for contribution to the modeling process, and treatment of revenues from sales of excess energy.

The direct access and sales revenue issues have been addressed in other Commission decisions, as described above, and we need to ensure that our allocation of DWR's revenue requirement here reflects the effects of those decisions, but we cannot do so without the assistance of DWR and the parties. As noted above, the resource and modeling assumptions underlying the revenue requirement implemented in this order must be applied using the methodologies adopted in D.02-10-022 for computing the applicable DA CRS cost elements. These are basically technical adjustments or updates that DWR and the parties in R.02-01-011 are already aware of. A separate ruling will be issued scheduling in more detail the process to be followed to implement the calculation of the DA

CRS elements applicable to the DWR power charge. If DWR (or anyone else) has questions or concerns on how these issues should be treated, they should contact the staff of the Commission's Energy Division for guidance.

Ancillary services appears to be an area where DWR can significantly reduce its revenue requirement by using more current assumptions, and by obtaining further input from the utilities.

The issues relating to the use of PROSYM 36 versus PROSYM 37 are procedural in nature. In order to ensure that similar difficulties are not presented by DWR's supplemental determination, we will set out a process for implementing that determination.

All utilities and other parties who wish to make suggestions to DWR relating to the input, assumptions and processes to be used in the modeling and preparation of its supplemental determination shall provide those suggestions no later than December 30, 2002. DWR can then incorporate those suggestions it deems appropriate, along with the direct access and sales revenues adjustments, and any other updates or corrections made by DWR. We encourage DWR to incorporate all reasonable reductions to its 2003 revenue requirement, including reductions in reserve requirements and results of contract renegotiations, as well as any other reductions that come to its attention. After it performs the ensuing model run and post-processing, DWR will submit its supplemental determination to the Commission.

The Commission will then use the supplemental determination to re-allocate DWR's 2003 revenue requirement on a highly expedited basis. In order to avoid unnecessary delay in implementing the revised allocation, the Commission will use the methodology approved today, with the exception of the allocation of ancillary services. Re-litigation of the allocation methodology will not be allowed (again with the exception of ancillary services), absent extraordinary circumstances. The Commission intends to hold a technical workshop, conducted by the Commission's Energy Division shortly after DWR submits its supplemental determination, to ensure that all parties have a common understanding of the supplemental determination. After the workshop will come an expedited proceeding, followed by a decision implementing a revised allocation for 2003.

Since the revised allocation should be fairer, and should also reflect a reduced revenue requirement, the sooner it can be implemented, the better. We accordingly urge DWR to prepare and submit its supplemental determination as quickly as possible, consistent with all legal and procedural requirements.

Rehearing and Judicial Review

This decision construes, applies, implements, and interprets the provisions of Assembly Bill (AB)1X (Chapter 4 of the Statutes of 2001-02 First Extraordinary Session). Therefore, Pub. Util. Code § 1731 (c) (applications for rehearing are due within 10 days after the date issuance of the order or decision) and Pub. Util. Code § 1768 (procedures applicable to judicial review) are applicable.

Comments on Proposed Decision

The alternate decision of the President Lynch was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure. Comments on the alternate proposed decision were received from SDG&E. Comments on the proposed decision of ALJ Allen are discussed below.

SCE

SCE reprises its request for authorization to use the Catch-Up Surcharge revenues to offset increases in procurement costs. SCE provides significant elaboration of the need for and propriety of that authorization. SCE explains the relationship between the Catch-Up Surcharge and the settlement of the filed rate doctrine litigation between SCE and the Commission. Furthermore, SCE describes how and why a rate increase would be required absent Commission approval of its use of Catch-Up Surcharge revenues. PG&E supports SCE's request (and seeks similar authorization itself); SDG&E, ORA and DWR take no position on this request. SCE has persuaded us of the merits of its request, and we have modified the decision to reflect our granting of the requested authorization for SCE.[24]

SCE attempts to reargue the merits of its "costs follows contracts" methodology, claiming that the Proposed Decision failed to recognize its virtues of logical consistency, finality and financial certainty, and simplicity. SCE's criticism is not well founded. The Proposed Decision considered all of these claims, and acknowledged the consistency and simplicity of SCE's proposal, as well as SCE's claim of procedural finality. SCE did not show, and probably could not show, that its proposed methodology would actually provide a fair result, or even a knowable result, given the current status of contract renegotiation. Secondly, while SCE is correct that its methodology may provide greater finality in regards to proceedings before this Commission, SCE is incorrect that its proposal would provide greater "financial certainty." While the fact of contract renegotiation causes some financial uncertainty under all of the proposals, that uncertainty is maximized under SCE's proposal, as the full impact of each contract renegotiation (or the lack of successful renegotiation) would hit one utility, rather than being distributed among all three utilities.

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[24] This decision does not adjudicate or determine any issues relating to the duration of the Catch-Up Surcharge.

PG&E opposes SCE's proposal, calling it arbitrary and unfair. We agree, and will not change the fundamental allocation method from that adopted in the Proposed Decision.

SCE argues that a more defined true-up mechanism is necessary to ensure that the costs and benefits of utility dispatch decisions flow to the customers of the utility making those decisions. We agree that the costs and benefits of utility dispatch decisions should flow to the appropriate customers, but we disagree that a pre-defined true-up mechanism and balancing accounts are necessary to track the relevant costs and revenues. The utilities may keep whatever records they need in order to track the costs and revenues.[25] A uniform system of tracking costs and revenues would be useful, and we will address that idea later in this proceeding, as there is no specific proposal for such a system presented here.

SCE expresses concern with the level of DWR's revenue requirement, and calls on DWR to take corrective action in its supplemental determination. Specifically, SCE recommends that DWR immediately address the need for $1 billion in reserves in light of the Commission's order that utilities resume procurement responsibilities as of January 1, 2003. We share this concern, and concur in SCE's recommendation that DWR promptly examine the possibility of reducing its level of reserves.

SCE argues that the Proposed Decision's treatment of surplus sales revenues is inconsistent with the proposed treatment of those revenues in R.01-10-024. We disagree. In the language from the Draft Decision of ALJ Halligan cited by SCE, an exception from the standard treatment is made for Ancillary Services and ISO Instructed Energy, on the grounds that less utility

[25] DWR also makes this point in its Reply Memorandum.

discretion is involved in scheduling these resources. By contrast, in this proceeding SCE is proposing an exception for transactions it claims were not contemplated by D.02-09-053, particularly off-system sales from resources located outside the ISO control area. The fact that an exception was proposed in R.01-02-024 does not provide a basis for creating a very different exception in this proceeding.

SCE recommends that the Commission not allocate the $170 million of the revenue requirement for ancillary services "until DWR provides additional information on the appropriateness of these charges." [SCE Comments, p. 13.] DWR does not agree, and states that it does not intend to reduce its revenue requirement for ancillary services "until the utilities are actually paying for ancillary services costs in 2003 and can continue to do so." [DWR Reply Memorandum, p. 3.] Accordingly, we must reject SCE's recommendation.

SCE recommends a clarification in language addressing the treatment of tolling charges. SCE points out that in one place the Proposed Decision states that "tolling charges associated with DWR must-take contracts" should be treated as fixed costs, while in another place it states "we will treat charges associated with tolling contracts as fixed costs." These two statements are not consistent, and the second one is incorrect. We will clarify the identified language, consistent with SCE's recommendation that tolling charges associated with must-take contracts are to be treated as fixed costs, but tolling charges that can be avoided by dispatch decisions be treated as variable costs.

PG&E

PG&E believes that the decision should be more specific regarding how pre-direct access net delivered energy should be calculated. We believe that the decision is already quite specific regarding the relevant calculations, and we do not understand the relevance of calculating delivered energy when the adopted allocation methodology uses supplied energy.[26] We will not make this modification.

PG&E recommends that the Commission reduce DWR's revenue requirement by $850 million "to reflect the fact that after January 1, 2003, DWR is not anticipated to be procuring power to meet the utilities' residual net short positions." [PG&E Comments, p. 3.] According to PG&E, once DWR is no longer purchasing to meet the utilities' residual net short, the requirement for DWR's Minimum Operation Expense Available Balance decreases from $1 billion to $150 million. While this a very attractive result, we cannot do as PG&E suggests, at least for the time being. As PG&E notes, we could only take such an action "once these reserves are no longer required." We cannot yet know with 100% certainty that such reserves are no longer required, and we must consult with DWR before undertaking such an adjustment.

DWR currently opposes PG&E's recommendation, stating that the proposed reduction in DWR's operating account balance and operating reserves can only happen after DWR has determined that it will not be responsible for procuring any of the utilities' net short in 2003, and after DWR has determined that a reduction in its operating account or operating reserve account will not result in an adverse impact on its credit rating, and after DWR has consulted with the Commission in accordance with the rate agreement concerning the reduction of the operating reserves, none of which have happened yet.

In the alternative, PG&E recommends that if we do not lower DWR's 2003 revenue requirement at this time, that:

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[26] SDG&E also opposes PG&E's recommendation.

> [T]he Commission should make clear in the final decision that the final allocation of the DWR 2003 revenue requirement, to be determined as quickly as possible at the beginning of 2003, must reflect any reduction in DWR's revenue requirement due to the utilities' resumption of purchasing to meet their residual net short positions.
>
> Indeed, the final decision should make clear that the early 2003 expedited proceeding to finalize the allocation of the DWR revenue requirement should reflect all reasonable reductions to DWR's 2003 revenue requirement, whether associated with changed circumstances that change the reserve requirements of the financing documents, DWR contract renegotiations, or any other reason. (PG&E Comments, pp. 4-5.)

We agree, and incorporate the recommended language.

In its comments, PG&E argues that the Proposed Decision should be modified so that variable DWR contract costs and ancillary services costs are remitted by each utility on an actual, incurred cost basis. PG&E contends that this approach is consistent with the Rate Agreement. DWR opposes PG&E's arguments, and counters that PG&E's proposals are neither necessary nor proper.

While we are sympathetic to the substance of PG&E's arguments, and support their goal of reducing costs to utility customers, PG&E fails to take into account provisions in the Rate Agreement that are reflected in the Servicing Order that the Commission has adopted for PG&E.

The Rate Agreement defines "Power Charges" as "charges imposed by the Commission upon Retail End Use Customers for electric power deemed sold to Retail End Use Customers by the Department." Under section 6.1 of the Rate Agreement the Commission agrees to impose Power Charges sufficient to provide moneys necessary to satisfy DWR's Retail Revenue Requirements and acknowledges that, as provided by Section 80112 of the Water Code, Power Charges are the property of DWR.

These concepts are further implemented in Section 2.3 of PG&E's Servicing Order, which provides, inter alia, that PG&E is acting solely as the servicing agent for DWR with respect to DWR Charges and that DWR retains title to all DWR Charges. That section further provides that "[t]o the extent any moneys are received by [PG&E] during the process of collection, and pending their transfer to DWR, the moneys shall be segregated by [PG&E] and shall be held in trust for the benefit of DWR." Section 2.2(d) of Service Attachment 1 to PG&E's Servicing Order addresses related topics, and provides that "the Consolidated Utility Bill shall (i) at all times contain a separate line item for Bond Charges and (ii) . . . contain a statement to the effect that the Consolidated Utility Bill includes Charges for power provided by DWR for which DWR is collecting "X" cents per kilowatt hour (where X = the current Power Charge)."

Thus, under the Rate Agreement, the Servicing Order, and the Proposed Decision, a Power Charge is established to recover all of DWR's revenue requirement that is not recovered by the Bond Charge. This Power Charge is imposed upon the end-use customer, is the property of DWR, and is to be segregated by PG&E and held in trust for DWR during the collection process.

In contrast, under PG&E's recommended approach, the Commission would now set a per kilowatt Power Charge that does <u>not</u> cover ancillary services costs or variable DWR contract costs. Instead, the utility would somehow pay these costs to DWR on an actual incurred basis. PG&E does not explain how this could be done while still recovering these costs directly from end-use customers as part of a Power Charge that is stated on the customer's bill to be in the amount of X cents per kilowatt hour. Rather, it appears that under PG&E's approach these costs would be paid by the utility to DWR. Such an approach would be in contravention of the Rate Agreement that requires these costs to be recovered directly from end use customers.

In its reply comments, PG&E argues that if it is acceptable for the utilities to remit surplus sales revenue to DWR on an actual basis, then it should be acceptable to remit variable contract costs and ancillary service costs on an actual basis. This argument ignores the distinction between remitting revenues and "remitting" costs. It is acceptable to remit revenues on an as-received basis because revenues are recovered outside the Power Charge (per the Operating Order), from buyers other than end use customers. In contrast, it is <u>not</u> acceptable to remit costs (*e.g.*, ancillary services costs) on an as-incurred basis because costs must be collected through the pre-established Power Charge, which in turn must be collected from ratepayers (per the Servicing Order).

We cannot, and accordingly do not, adopt the modifications requested by PG&E relating to remittance of variable contract costs and ancillary services costs.

While PG&E states that the calculation approach used by the Commission regarding surplus sales is reasonable, PG&E states that the "operational implementation" of the Commission's treatment of surplus sales should be addressed in a different proceeding, rather than in the context of the allocation of DWR's revenue requirement. It is not entirely clear what PG&E is requesting, as PG&E does not make any specific recommendations. We make no changes in this area other than minor wording clarifications.

PG&E recommends that the language of the decision be modified to reflect the interaction of this proceeding with the Direct Access Cost Responsibility

Surcharge (DA CRS) addressed in D.02-11-022. PG&E refers to workshops that were anticipated in that decision. Consistent with the Joint Ruling issued on December 10, 2002 in this proceeding and in R.02-01-011, we will implement a DA CRS of 2.7 cents/kWh on January 1, 2003, prior to the modeling implementation workshops.

PG&E requests, similarly to SCE, authorization to use the half-cent per kWh Catch-Up Surcharge to partially offset the increase in DWR's revenue requirement. However, PG&E's situation differs from that of SCE, and PG&E has not shown that it actually needs the revenues from the Catch-Up Surcharge in order to avoid a rate increase. At this time we will not grant PG&E's request relating to revenues from the Catch-Up Surcharge.

PG&E asserts that some numbers in the Proposed Decision do not appear to match the record. PG&E is correct that Lines 16 and 17 in Appendix A were mislabeled, and they have been relabeled. PG&E observes that "with respect to Table C, as is noted in the Assistant Chief Administrative Law Judge's Ruling Regarding Proposed Decision Of ALJ Allen And Alternate Proposed Decision Of Commissioner Lynch, multiplying the power charge by the DWR delivered energy does not give the DWR revenue required from customers. PG&E is unable to confirm that this is consistent with DWR's request." (PG&E Comments, p. 14.)

The difficulty noted by PG&E regarding the "transparency" of the calculation of DWR's revenue requirement stems from the complexity of the financial model submitted by DWR in support of its August 16th Determination. For this reason, it is not possible to confirm the accuracy of the power charges with the simple calculation described by PG&E, as sensible at that approach may seem. DWR assumes that it will receive ratepayer funds 45 days after power is delivered to ratepayers. Thus, even though the DWR power charges will change on January 1, 2003, the revenue collected via these charges is not assumed to begin reaching DWR until February 15, 2003. Prior to that day, DWR's daily receipts from ratepayers in 2003 are calculated using the power charges that are currently in effect, which are somewhat lower than the charges adopted in this decision. This is why simply multiplying the retail DWR sales in calendar 2003 by the IOU-specific power charges does not produce a result equal to the DWR revenue required from customers, as PG&E expected: the last 45 days of the revenue collected by the 2003 power charges will in fact reach DWR in calendar year 2004, because of the assumed lag in receipt of revenues.

In its Reply Comments, PG&E for the first time presents a proposal to create a proxy for the unavailable DA-in modeling run, so that the Commission can incorporate an estimate of what PG&E calls "pre-direct access direct energy." (PG&E Reply Comments, pp. 4-5.) This is a new recommendation on a complex and somewhat controversial topic, and its presentation in Reply Comments fails to provide an adequate opportunity for other parties to address it. We will not implement PG&E's proposal.

SDG&E

SDG&E argues that a paper-only proceeding is inadequate to deal with the potentially complex and controversial technical issues that may be presented by a supplemental determination from DWR. This is a valid concern, so while we remain committed to an expedited process, we will allow the ALJ and Assigned Commissioner(s) to determine the appropriate procedural approach, rather than make that determination here.

SDG&E recommends that the Commission review any supplemental determination provided by DWR concurrently with the true-up of the 2001-2002 revenue requirement. While this would be procedurally simpler, we are hoping that DWR will provide its supplemental determination significantly earlier than the anticipated date of the true-up phase of this proceeding. PG&E opposes SDG&E's recommendation, on the grounds that it would needlessly delay Commission action on the supplemental determination. We agree with PG&E that the revenue requirement and its corresponding inter-utility allocation should be revised as quickly as possible. We will not make SDG&E's requested change, and we will leave such scheduling and procedural matters to the discretion of the ALJ and Assigned Commissioner(s), with an exhortation to DWR to submit its supplemental determination early in 2003, well before the true-up phase of this proceeding.

SDG&E notes that the Commission should more clearly state that the implementation date for interim rates is January 1, 2003. We have clarified the decision to state that interim charges go into effect January 1, 2003.

SDG&E recommends that the Commission make clear that when a pre-load migration adjustment is made to the adopted allocation, such a calculation should not include continuous direct access load. ORA agrees with SDG&E that references to DA migration in the decision should refer only to non-continuous direct access load. This is generally correct, but SCE further elaborates on this issue:

> SCE believes that the appropriate DA load adjustment should reflect that portion of DA load that is subject to a CRS for DWR going-forward contract costs. Pursuant to D.02-11-022, that is currently any DA load that took bundled service on or after February 1, 2001. (SCE Reply Comments, p. 3.)

We make the change recommended by SDG&E and ORA, with SCE's clarification.

SDG&E repeats its request that the cost of ancillary services be removed from DWR's revenue requirement, and provides a new argument for its request, based upon ALJ Halligan's Draft Decision in R.01-10-024, and a DWR exhibit in that proceeding. The exhibit cited by SDG&E reads, in relevant part, "The financial obligation for ISO charges will be allocated to the Utility, unless otherwise extended…" SDG&E focuses upon the first phrase, and the Halligan DD's recommendation that the full responsibility for ISO charges revert back to the utilities. The "unless otherwise extended" language, however, presents a problem. It means that the financial obligation for ISO charges, such as ancillary services, may not revert back to the utilities. DWR makes this point in its Reply Memorandum: "[U]ntil the utilities are actually paying for ancillary services costs in 2003 and can continue to do so, the Department does not intend to reduce its Determination of Revenue Requirements to reflect this fact." (DWR Reply Memorandum, p. 3.) While we are sympathetic to SDG&E's request, particularly as it is the utility least likely to need DWR to purchase ancillary services on its behalf, we still cannot remove the $170 million for ancillary services from DWR's revenue requirement.

SDG&E believes that the $0.00931 cent/kWh "Charge Component to Fund Operating Account" from the corrected Table C collects approximately $100 million or 33 percent more than the $307,752,619 of revenue to maintain Operating Account above $1 billion also shown in the corrected Table C. SDG&E, therefore, requests that the Commission consider a prospective decrease in this Charge Component to Fund Operating Account, if it is indeed at a higher level than otherwise necessary due to the fluctuating daily balances in the Operating Account. (SDG&E Comments, p. 4.)

Essentially, setting the power charge high enough to maintain the operating account balance above $1 billion has the indirect effect of leaving DWR's accounts $307 million higher at the end of 2003 than at the beginning of the year. But it is a residual effect of the solution for the power charges, rather than a directly calculated "revenue requirement" item. Since the total power charges are set to get DWR over a low-balance "hurdle" in mid-2003, and since DWR's deliveries of power are higher in the second half of 2003, any fixed charge set in this manner will have the result of producing "excess" revenues in the DWR operating account by the end of 2003. The $307,752,619 shown in Table C is simply the result of this effect: it is the calculated difference between the operating account balance on 12/31/2003 and 12/31/2002

DWR

DWR observes that the Proposed Decision refers to allocation of DWR costs to the utilities, but under the Rate Agreement the costs are to be allocated to the customers located within the relevant utilities' service territories. DWR is correct; references to allocation of DWR costs to utilities should be read as allocating those costs to the customers of those utilities.

DWR also notes that the Proposed Decision states that the utilities should remit DWR's share of surplus sales revenue directly to DWR on an actual incurred cost basis, but it would be more appropriate to state that such revenue be remitted directly to DWR on "an actual receipts basis." DWR is correct, and we will make this correction.

DWR raises an issue relating to the treatment of power sales by PG&E to the Western Area Power Administration (WAPA), and states that DWR has not received from PG&E the revenue associated with such power sales. While we urge PG&E and DWR to resolve this issue promptly, this is not the appropriate place to address what appears to be a billing or payment dispute that was not litigated in this proceeding. If DWR believes the Commission needs to take action on this dispute, DWR should make use of the appropriate processes for bringing the issue before the Commission.

ORA

ORA's Comments generally support the adoption of the Proposed Decision, and recommend no changes.

Assignment of Proceedings

Loretta M. Lynch and Geoffrey F. Brown are the Assigned Commissioners and Peter Allen is the assigned Administrative Law Judge in these proceedings.

Findings of Fact

1. Among the allocation methodologies proposed in this proceeding, ORA's proposed allocation methodology is both consistent with recent Commission decisions and provides the fairest allocation of DWR's 2003 revenue requirement.

2. ORA's proposed allocation methodology should be modified to reflect differences in line loss among the utilities to avoid cross-subsidies.

3. Using revenues from surplus sales to directly offset the revenue requirement of the dispatching utility provides a better incentive for economic dispatch than would pooling of revenues from surplus sales.

4. Allocation of DWR's revenue requirement should take into consideration direct access customers subject to the Cost Responsibility Surcharge (CRS) set in R.02-01-011.

5. Consideration of direct access customers subject to the Cost Responsibility Surcharge (CRS) set in R.02-01-011 requires the results of a "Direct Access-In" modeling run from DWR's consultant.

6. A "Direct Access-In" modeling run was not available in time to become part of the evidentiary record in this proceeding.

7. D.02-09-053 required that revenues from sales of excess energy should be allocated pro rata between DWR and the utilities.

8. DWR's August 16 Determination does not reflect the treatment of revenues from sales of surplus energy adopted in D.02-09-053.

9. Crediting of revenues from the sale of excess energy to the customers of the utility involved in the transaction provides the proper incentives for utilities to maximize the revenues from sales of surplus energy.

10. Utilities are not required to obtain ancillary services through DWR.

11. Utilities differ in their potential need for DWR to provide ancillary services in 2003.

12. DWR's August 16 determination does not reflect differences between utilities relating to DWR provision of ancillary services.

13. DWR's August 16 Determination was based upon a modeling run known as PROSYM 36.

14. PROSYM 36 does not reflect the treatment of excess energy sales revenue adopted in D.02-09-053.

15. PROSYM 36 does not contain the most recent data and assumptions.

16. The output of the modeling run known as PROSYM 37 was presented too late in the proceeding to allow all parties a reasonable opportunity to evaluate and address its contents and impacts.

17. A supplemental determination from DWR that provides the necessary additional information would allow the Commission to improve the accuracy and equity of its allocation of DWR's 2003 revenue requirement.

18. Significant changes in the procedures for making remittance payments to DWR are not necessary.

19. PG&E's proposal to alter the procedures for remittance payments to DWR is a significant change to current practices and is opposed by DWR.

20. The evidentiary record does not contain accurate information about the volume of direct access sales that will be subject to the surcharge ordered in D.02-11-022.

21. D.02-11-022 authorized collection of an interim capped DA CRS of 2.7 cents per kWh beginning on January 1, 2003.

22. Actual data for DWR's revenue requirement for the year 2002 will not be available until 2003.

23. With DWR's agreement, ALJ Allen deferred all issues relating to the true-up of DWR's 2001-2002 revenue requirement until 2003.

24. Absent utilization of the Catch-Up Surcharge, SCE will require a rate increase as a consequence of its customers' share of DWR's 2003 revenue requirement.

25. D.02-08-071 authorized PG&E and SCE to enter into power contracts using the credit backing of DWR, but did not authorize SDG&E to do so.

26. DWR includes $29 million in its proposed revenue requirement for demand reduction efforts.

27. Assembly Bill 1X does not give DWR the authority to incur costs for demand reduction programs or to charge such costs to utility customers.

Conclusions of Law

1. ORA's proposed methodology, with the modifications described above, should be adopted.

2. A “Direct Access-In” modeling run should be utilized for allocation when it becomes available, consistent with due process.

3. Until a “Direct Access-In” modeling run becomes available, a modeling run without “Direct Access-In” should be utilized.

4. Revenues from sales of excess energy should offset the portion of the DWR revenue requirement allocated to the customers of the dispatching utility.

5. DWR’s August 16 Determination, October 23 Memorandum, and the Rate Agreement preclude the Commission from allocating to a utility the actual costs that DWR incurs for providing ancillary services to that utility.

6. The use of PROSYM 37 at this time would not be consistent with due process.

7. The use of PROSYM 36 at this time does not present due process issues.

8. A supplemental determination from DWR, as described above, could remedy the due process problems of using an updated modeling run.

9. All parties should have equal opportunity to provide input to DWR’s supplemental determination, and should be subject to the same deadline.

10. Utilities should generally maintain their current processes for remitting funds to DWR.

11. Changes to current remittance practices should be limited to those necessitated by Commission decisions subsequent to D.02-02-052.

12. Each utility should remit DWR’s share of surplus sales revenue directly to DWR on an actual receipts basis.

13. The Rate Agreement bars the utilities from remitting variable costs and ancillary services costs directly to DWR on an actual incurred-cost basis.

14. Calculation of the power charge should use DWR retail sales adjusted to reflect the protocol for surplus sales adopted in D.02-09-053.

15. An interim DA CRS of 2.7 cents per kWh can be implemented on January 1, 2003, subject to adjustment.

16. It is reasonable to defer until 2003 all issues relating to the true-up of DWR's 2001-2002 revenue requirement.

17. It is consistent with Commission precedent and the purpose of the Catch-Up Surcharge to allow SCE to use revenues from that Surcharge to defer a rate increase.

18. Any 2003 DWR revenue requirement pertaining to power contracts entered into by DWR between August 22, 2002 and January 1, 2003 (pursuant to D.02-08-071) should be allocated to the utility entering the particular contract.

19. This decision construes, applies, implements, and interprets the provision of AB 1X (Chapter 4 of the Statues of 2001-02 First Extraordinary Session). Therefore, Pub. Util. Code § 1731 (c) (applications for rehearing are due within 10 days after the date of issuance of the order or decision) and Pub. Util. Code § 1768 (procedures applicable to judicial review) are applicable.

20. Costs for demand reduction programs cannot be included in DWR's revenue requirement and charged therein to ratepayers.

O R D E R

IT IS ORDERED that:

1. Department of Water Resources' (DWR's) 2003 revenue requirement is to be allocated according to the allocation methodology proposed by Office of Ratepayer Advocates (ORA), as modified and described above, and as set forth in Appendix A. The corresponding charges shown in Table C shall go into effect on January 1, 2003, and remain in effect until further order of the Commission.

2. Based on the adopted allocation methodology, DWR's total 2003 revenue requirement is allocated to the customers of the three utilities as follows:

PG&E:	$1,965,158,417
SCE:	$1,879,525,727
SDG&E:	$ 643,087,606

3. Revenues from excess sales are to be accounted for as described above.

4. DWR's forecast ancillary services costs are to be allocated on the same basis as fixed costs until an improved allocation method is approved by the Commission.

5. No later than December 30, 2002, parties may submit information and assumptions for DWR's use in a supplemental determination. If parties do so, they shall also file such information and assumptions at the Commission's Docket Office and serve them on all parties to this proceeding.

6. DWR is encouraged to promptly submit a supplemental determination, as described above.

7. Each utility shall remit DWR's share of surplus sales revenue directly to DWR on an actual receipts basis.

8. Calculation of the power charge shall use DWR retail sales adjusted to reflect the protocol for surplus sales adopted in D.02-09-053, as described above.

9. The respective servicing agreement or Commission order for each utility should be modified to the extent necessary to be consistent with the approaches described above.

10. Within seven days of the issuance of today's decision, SCE, PG&E, and SDG&E shall file advice letters with revised tariffs to implement the Direct Access Cost Responsibility Surcharge (DA CRS) at the interim capped level of 2.7 cents per kWh approved in D.02-11-022. The revised tariffs will become

effective on January 1, 2003, subject to Energy Division's determination that they comply with applicable statutes and Commission Decisions. Except for the Bond Charge component of the DA CRS, the utilities shall initially apply the revenues from the 2.7 cent DA CRS to the DWR Power Charge for 2003, and we permit SCE to recoup its one-cent historic procurement charge from these revenues. Once the Commission's determination regarding the Bond Charge component of the DA CRS in D.02-11-022 becomes final and unappealable, the utilities shall apply revenues from the DA CRS according to the priority in Ordering Paragraph 20 of D.02-11-022.

11. For DA customers that have remained continuously on DA, and did not take bundled service on or after February 1, 2001, pursuant to D.02-11-022 the applicable DA CRS shall be limited to the Historic Procurement Charge (HPC), applicable to SCE customers only. The determination of the utility retained generation component of the DA CRS to be charged to continuous DA customers shall occur as part of the pending implementation workshops.

12. Any true-up of DWR's 2001-2002 revenue requirement is deferred until actual data for 2002 is available, consistent with the ruling of ALJ Allen.

13. SCE may use revenues from the Catch-Up Surcharge to offset its share of DWR's 2003 revenue requirement, as described above.

14. Any 2003 DWR revenue requirement pertaining to power contracts entered into by DWR between August 22, 2002 and January 1, 2003 (pursuant to D.02-08-071) shall be allocated to the customers of the utility entering the relevant contract.

15. The Commission or Assigned Commissioner or ALJ shall issue further orders or rulings as needed regarding the process and schedule of future phases of this proceeding.

16. $29 million for demand reduction programs is removed from DWR's proposed revenue requirement.

This order is effective today.

Dated December 17, 2002, at San Francisco, California

LORETTA M. LYNCH
President
CARL W. WOOD
GEOFFREY F. BROWN
Commissioners

I dissent.

/s/ HENRY M. DUQUE
Commissioner

I dissent.

/s/ MICHAEL R. PEEVEY
Commissioner

APPENDIX A

Appendix A
Allocation Methodology for 2003 DWR Revenue Requirement

1) Calculate each IOU's portion of DWR Pre-DA migration supplied energy.

a) Calculate the proportion of the DWR- and URG-supplied energy in each IOU's resource portfolio

Line	GWh	PG&E	SCE	SDG&E	Total	Source
1	Supply from URG	52,756	57,881	7,056	117,693	ProSym 36
2	Supply from DWR	21,835	22,246	6,953	51,034	ProSym 36
3	Total Supplied Energy	74,591	80,127	14,009	168,728	Line 1 + Line 2
4	URG % of IOU Portfolio	71%	72%	50%	N/A	Line 1 / Line 3
5	DWR % of IOU Portfolio	29%	28%	50%	N/A	Line 2 / Line 3

b) Adjust the amount of DWR supplied energy for each IOU by adding DWR's share of Pre-DA migration to DWR supplied energy.

Line	GWh	PG&E	SCE	SDG&E	Total	Source
6	Direct Access	0	0	0	0	Need Supplemental DWR Modeling
7	Departing Load	0	0	0	0	Need Supplemental DWR Modeling
8	Total DA/DL Migrated Load	0	0	0	0	Line 6 + Line 7
9	DWR Share of Portfolio	21,835	22,246	6,953	51,034	Line 2 + Line 8

c) Subtract DWR's portion of surplus energy from DWR supplied energy to determine DWR's adjusted supplied energy.

Line	GWh	PG&E	SCE	SDG&E	Total	Source
10	Total Surplus Energy*	2,710	7,052	133	9,895	ProSym 36
11	URG Share of IOU Portfolio	1,979	5,159	64	7,202	Line 10 * Line 4
12	DWR Share of IOU Portfolio	731	1,893	69	2,693	Line 10 * Line 5
13	Adjusted DWR Supplied Energy	21,104	20,353	6,884	48,341	Line 9 – Line 12

*In its Allocation Comparison Exhibit, ORA used surplus sales numbers that were cash based, not accrued. To accurately model the impact of D.02-03-059 on surplus energy sales and revenues, the Energy Division applied the surplus sales allocation methodology outlined in D.02-09-053 to monthly surplus energy sales and revenue. The results of these calculations are reflected on Lines 11 and 12.

d) Calculate URG and DWR share of revenue from surplus sales.

Line		PG&E	SCE	SDG&E	Total	Source
14	Revenue from Surplus Sales*	($33,586,940)	($93,371,835)	($1,927,165)	($128,885,940)	ProSym 36
15	Utility Share of Surplus Revenue	($24,444,018)	($68,035,638)	($923,002)	($93,402,658)	Line 14 * Line 4
16	DWR Share of Surplus Revenue	($9,142,922)	($25,336,197)	($1,004,163)	($35,483,282)	Line 14 * Line 5

*In its Allocation Comparison Exhibit, ORA used surplus sales numbers that were cash based, not accrued. To accurately model the impact of D.02-03-059 on surplus energy sales and revenues, the Energy Division applied the surplus sales allocation methodology outlined in D.02-09-053 to monthly surplus energy sales and revenue. The results of these calculations are reflected on Lines 14, 15, and 16.

2) Calculate the adjusted DWR Revenue Requirement and allocate to each IOU

a) Start with DWR's 2003 August 16th Determination Revenue Requirement

Line	2003 DWR Revenue Requirement		Source
17	Power Costs	$4,119,902,243	August 16th Determination
18	Administrative & General Expenses	$28,400,000	August 16th Determination
19	Increase in Operating Fund Balance*	$0	
20	Ancillary Services	$170,454,426	August 16th Determination
21	**Less:**		
22	Revenue from Surplus Sales**	$0	ProSym 36
23	Interest Earnings on Fund Balance	($59,007,505)	August 16th Determination
24	DWR Revenue Requirement	$4,259,749,164	

*Operating fund balance is initially set to zero and then calculated once everything else has been allocated to the IOUs. See step 2.e

** Surplus sales are directly assigned to the IOUs per D.02-09-053. See step 2.d.

b) Calculate each IOU’s supplied energy allocation factor by dividing each IOU’s portion of DWR supplied energy by the total DWR supplied energy

Line		PG&E	SCE	SDG&E	Total	Source
25	DWR Supplied Energy	21,104	20,353	6,884	48,341	Line 13
26	% DWR Supplied Energy	43.66%	42.10%	14.24%	100%	Line 25 / Total Line 25

c) Determine each IOU's share of the DWR Revenue Requirement by multiplying the adjusted DWR Revenue Requirement by each IOU's supplied energy allocation factor.

Line		PG&E	SCE	SDG&E	Total	Source
27	Adjusted DWR Revenue Requirement				$4,259,749,164	Line 24
28	% Pre-load Migration Supplied Energy	43.66%	42.10%	14.24%	100%	Line 26
29	IOU Share of Adjusted DWR Revenue Requirement	$1,859,628,380	$1,793,485,733	$606,635,051	$4,259,749,164	Line 27 * Line 28

d) Determine each IOU's share of the DWR Revenue Requirement by multiplying the adjusted DWR Revenue Requirement by each IOU's supplied energy allocation factor.

Line		PG&E	SCE	SDG&E	Total	Source
30	IOU Share of Adjusted DWR Revenue Requirement	$1,859,628,380	$1,793,485,733	$606,635,051	$4,259,749,164	Line 29
31	DWR's share of Surplus Sales Revenue	$9,142,922	$25,336,197	$1,004,163	$35,483,282	Line 16
32	IOU Share of DWR Revenue Requirement less operating fund balance	$1,850,485,458	$1,768,149,536	$605,630,887	$4,224,265,882	Line 30 - Line 31

e) Solve the DWR model to determine the additional revenue required to maintain the operating account balance at or above $1 billion and then allocate that undercollection to the IOUs to determine the final DWR Revenue Requirement allocation.

Line		PG&E	SCE	SDG&E	Total	Source
33	IOU Share of Adjusted DWR Revenue Requirement	$1,850,485,458	$1,768,149,536	$605,630,887	$4,224,265,882	Line 32
34	Operating Reserves	$134,351,926	$129,573,341	$43,827,352	$307,752,619	Line 34 total * Line 28
35	Final allocation of DWR Revenue Requirement	$1,984,837,384	$1,897,722,878	$649,458,239	$4,532,018,501	Line 33 + Line 35

3) Power Charge Calculation

a) Determine the amount of dollars to be remitted for variable costs, fixed costs, ancillary services, and operating fund balance.

Line		PG&E	SCE	SDG&E	Total	Source
36	Allocation Factor	44%	42%	14%	0%	Line 28
37	Adjusted Rev Req.	$1,850,485,458	$1,768,149,536	$605,630,887	$4,224,265,882	Line 33
38	Less:					
39	Variable Costs	$85,661,819	$65,501,750	$68,722,250	$219,885,819	ProSym 36
40	Ancillary Services	$74,413,275	$71,766,569	$24,274,582	$170,454,426	Line 20 * Line 36
41	DA Cost Responsibility Surcharge Revenues	$0	$0	$0	$0	Need Implementation workshop
42	Fixed Costs	$1,690,410,363	$1,630,881,218	$512,634,056	$3,833,925,637	Sum of Line 37 thru Line 42
43	Operating Account Funds	$134,351,926	$129,573,341	$43,827,352	$307,752,619	Line 34

b) Calculate the IOU-specific DWR power charges

Line		PG&E	SCE	SDG&E	Total	Source
44	2003 DWR Delivered Energy (kWh)	19,205,963,516	18,459,409,403	6,398,534,999	44,063,907,918	ProSym 36
45	Variable Costs ($/kWh)	$0.00446	$0.00355	$0.01074	$0.00499	Line 39 / Line 44
46	Fixed Costs ($/kWh)	$0.08801	$0.08835	$0.08012	$0.08701	Line 42 / Line 44
47	Ancillary Services ($/kWh)	$0.00387	$0.00389	$0.00379	$0.00387	Line 40 / Line 44
48	Operating Account Funds ($/kWh)	$0.00931	$0.00931	$0.00931	$0.00931	DWR model solution
50	Total IOU Power Charge ($/kWh)	$0.10566	$0.10510	$0.10396	$0.10518	Sum of Line 45 thru Line 48

(END OF APPENDIX A)