STATE OF CALIFORNIA GRAY DAVIS, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

September 23, 2002

TO: ALL PARTIES OF RECORD IN RULEMAKING 01-10-024

Decision 02-09-053 is being mailed without the Dissent of President Loretta Lynch. The Dissent will be mailed separately.

Very truly yours,

/s/ ANGELA K. MINKIN for
CAROL A. BROWN, Interim Chief
Administrative Law Judge

CAB/tcg

ALJ/MEG/tcg **Mailed 9/23/2002**

Decision 02-09-053 September 19, 2002

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Cost recovery Mechanism for Generation Procurement and Renewable Resource Development.	Rulemaking 01-10-024 (Filed October 25, 2001)

INTERIM OPINION ON PROCUREMENT ISSUES: DWR CONTRACT ALLOCATION

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INTERIM OPINION ON PROCUREMENT ISSUES: DWR CONTRACT ALLOCATION

1. Introduction and Summary[1]

Since early 2001, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE), collectively referred to as "the utilities," have not purchased power for their customers' net short needs. By "net short" we refer to the difference between customer loads and the power already under contract to the utilities or generated from a utility-owned asset.

The Legislature enacted Assembly Bill (AB) X1-1 on January 31, authorizing the California Department of Water Resources (DWR) to make electricity purchases for the purpose of selling electricity to utility retail customers. This was necessary for at that time the utilities were not financially able to meet their net short needs.

Under the law, DWR's authority to contract for such purchases will expire on January 1, 2003. The Commission initiated this rulemaking to establish ratemaking mechanisms and procedures that would enable the utilities to resume the responsibility of procuring power for their customers. Today's decision addresses one of the outstanding issues that must be resolved before the utilities can submit final resource procurement plans or resume procuring their net short, i.e., the allocation among the utilities of the power contracted for by DWR.

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[1] Attachment 1 explains each acronym or other abbreviation that appears in this decision.

At present, DWR is managing thirty-five long-term contracts with twenty-four counterparties that cumulatively represent an average annual capacity of 10,780 MWs over the next seven years. The contracts range in term from two to twenty years, although the contracted capacity and energy drops off significantly after 2009. Some of the contract quantities are exclusively “must-take,” some are all dispatchable under the option of DWR, and others include a combination of both must-take and dispatchable purchases.

With DWR no longer in the business of procuring electric power on behalf of SCE’s, SG&E’s and PG&E’s customers as of January 1, 2003, we believe that the best way to coordinate DWR’s existing contracts with utility resources is to put them all in the utilities’ resource portfolios to be scheduled and dispatched in a least-cost manner. For this purpose, we allocate DWR contracts to PG&E, SCE and SDG&E as shown in Table 1.

TABLE 1 : Adopted DWR Contract Allocation

Long-Term Contract	Contract Category	Adopted Allocation
Allegheny 2 150 MW 6x16 in NP-15 for 2003	Must-Take	PG&E
Calpine 1 Product 1	Must-Take	PG&E
Calpine 2 Product 1	Must-Take	PG&E
Capitol Power	Must-Take	PG&E
Clearwood	Must-Take	PG&E
Constellation - Product 2 400 MW 7x24 May to Oct. '03	Must-Take	PG&E
Coral	Must-Take	PG&E
El Paso 50 MW 6x16 in NP-15	Must-Take	PG&E
Intercom	Must-Take	PG&E
Santa Cruz	Must-Take	PG&E
Soledad	Must-Take	PG&E
Allegheny1 Excluding NP-15 deliveries	Must-Take	SCE
Constellation 200 MW 6x16 through Jun. '03	Must-Take	SCE
Dynegy	Must-Take	SCE
El Paso 50 MW 6x16 in SP-15	Must-Take	SCE
Morgan Stanley	Must-Take	SDG&E
PGE&T Wind	Must-Take	SCE
Primary Power	Must-Take	SDG&E
Sempra	Must-Take	SCE
Whitewater Cabazon	Must-Take	SDG&E
Whitewater Hill	Must-Take	SDG&E
Williams	Must-Take	SDG&E
Calpine 1 - Product 2	Dispatchable	PG&E
Calpine 2 - Product 3 & 4	Dispatchable	PG&E
Calpine 3	Dispatchable	PG&E
Calpine SJ	Dispatchable	PG&E
Calpeak (3 contracts) New Site, Panoche, and Vaca-Dixon	Dispatchable	PG&E
GWF	Dispatchable	PG&E
Pacificorp	Dispatchable	PG&E
Wellhead (3 contracts) Fresno, Gates, and Panoche	Dispatchable	PG&E
Alliance	Dispatchable	SCE
Calpeak (3 contracts) Border, El Cajon, and Escondido	Dispatchable	SDG&E
Dynegy 1,000 MW On-Peak System Contingent	Dispatchable	SCE
High Desert	Dispatchable	SCE
Sunrise	Dispatchable	SDG&E

Our adopted allocation results in a reasonable middle ground among the various proposals with respect to each utility's share of power from the contracts, preliminary cost estimates and projected residual net short position.[2] In addition, our adopted allocation avoids the need for inter-zonal transfers as much as possible by allocating all quantities that have NP-15 (north of Path 15) specified delivery points to PG&E, and allocating contracts with SP-15 (south of Path 15) specified delivery points to SDG&E and SCE. It also strikes a reasonable balance with respect to contracts that involve some delivery uncertainties by distributing those contracts among all three utilities, i.e., Sempra to SCE, Sunrise to SDG&E and Coral to PG&E. In addition, our adopted allocation produces a resolution of the issues without requiring any utility to manage the contract of its affiliate.

The utilities can now move forward with their procurement planning knowing exactly what DWR contracts they will need to integrate into their resource portfolios. Today's decision eliminates the current two-tier procurement system in California that was put in place on a temporary basis, and only under emergency circumstances, until the utilities could resume their procurement role. As described in this decision, the utilities will now perform all of the day-to-day scheduling, dispatch and administrative functions for the DWR 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.

[2] The term "residual net short" refers to the power that the utility still needs to procure to meet loads after DWR contract quantities are allocated. It other words, it is the "net short," less those quantities.

We reiterate the long-standing principle that least-cost or "economic" dispatch should be the operating rule for the utility's portfolio of resources, including the DWR contracts that we allocate today. However, we reject SCE's and SDG&E's arguments that cost allocation must follow the allocation of contract power for operational purposes in order to achieve an economic dispatch. As discussed in this decision, variable costs are the only ones that are incurred for dispatch purposes--fixed costs are considered "sunk." Dispatch and operation of the DWR contracts does not require the allocation of total costs, any more than a utility requires the consideration of its total costs to dispatch its own utility retained generation.

Cost allocation of DWR's revenue requirement, which is comprised in large part of contract costs, will occur in the upcoming DWR revenue requirement proceeding. We leave the issue of contract cost allocation to be decided in that forum, where we will have all the relevant information concerning DWR's revenue requirement and can carefully examine cost allocation alternatives. However, based on the record in this proceeding, we establish the policy that the variable costs of each contract should follow contract allocation. This is necessary in order to ensure that utility dispatch decisions are based on the appropriate operating cost information. Accordingly, we direct DWR to present a contract-by-contract delineation between fixed and variable costs for our consideration in the DWR revenue requirement proceeding.

We also address various protocols with respect to how the dispatch or curtailment of DWR must-take contracts should be sequenced relative to other resources in the utility's portfolio, and how the sales of surplus capacity should be accounted for between DWR and the utilities, along with the corollary of how to account for retail sales. We find that sequencing protocols for this purpose are neither necessary nor appropriate in a procurement environment where the utility dispatches all resources from a single utility portfolio. Thus, we will allocate revenues from surplus sales between DWR and the utility based on the relative quantities dispatched from DWR contracts and from utility generating assets, including existing utility contracts and market purchases in the future.

This involves the following steps: (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). DWR and the utilities are directed to work together to develop specific accounting and reporting procedures consistent with this approach, and to submit those procedures in the DWR revenue requirement proceeding for our consideration.

The reasonableness of the utilities' administration of the DWR contracts we allocate today, including how they elect to dispatch the contract power quantities relative to other resources in their portfolio, shall be at issue over the life of the contracts. The forum for this review shall be the annual procurement proceedings, where the utility procurement process as a whole is reviewed.

2. Procedural Background

On October 29, 2001, the Commission issued an Order Instituting Rulemaking (OIR), designated as Rulemaking (R.) 01-10-024, to

> (1) establish ratemaking mechanisms to enable California's three major investor-owned electric utilities to resume purchasing electric energy, capacity, ancillary services and related hedging instruments to fulfill their obligation to serve and meet the needs of their customers, and

(2) consider proposals on how the Commission should comply with Public Utilities Code Section 701.3 which requires that renewable resources be included in the mix of new generation facilities serving the state.

A preliminary scoping memo contained in the OIR set a schedule for utilities to file procurement proposals, for interested parties to comment on the proposals, and scheduled a prehearing conference (PHC) for January 8, 2002. SDG&E and PG&E filed their proposals on November 21, 2001 and SCE late-filed its proposal on November 27, 2001. Interested parties requested and were granted a one-week extension until December 21, 2001 to file comments. In their comments, many parties urged the Commission to decide initially those issues that need to be in place for the utilities to resume full procurement responsibilities no later than January 1, 2003, as anticipated by ABX1-1. One of those issues was the allocation of DWR contracted purchases among the utilities.

The procedural schedule and scope for the initial proceeding was adopted in the April 2, 2002 Assigned Commissioner Ruling Establishing Category and Providing Scoping Memo (April 2 Scoping Memo). The ruling requested briefs on transition issues that needed to be resolved and set a schedule for the utilities to file procurement plans for 2003 with accompanying testimony. In preparing their procurement plans, the utilities were directed to allocate the DWR contract volumes as follows:

- For those contracts with specific delivery points/locations identified, the contract volumes are allocated to the utility in whose service territory the delivery point is located.
- Unless delivery points/locations are specified in the contracts, all NP-15 contract volumes should be allocated to PG&E and all SP-15 volumes to SCE and SDG&E.
- SP-15 contract volumes, without specific delivery points/locations identified are allocated among SCE and SDG&E using factors derived from the utilities net short positions, and

- SP-15 contracts with specific delivery points/locations identified within the utility service area should be allocated to the appropriate utility. For example, the Calpeak El Cajon contract volumes should be allocated solely to SDG&E.

In addition to using the above assumptions, the ruling directed the utilities to propose their preferred method for allocating the DWR contract volumes in their testimony.

The utilities filed their briefs on transition issues on April 12, 2002 and served their testimony on May 1, 2002. As part of this testimony, SCE proposed the Commission adopt a process by which it could immediately begin contracting for up to a five-year term for capacity and related products in conjunction with DWR. On May 6, 2002, SCE filed a motion requesting that this proposal be approved on an expedited basis outside of the hearing process.

By ruling dated May 15, 2002, the Assigned Commissioner and Administrative Law Judge (ALJ) issued a ruling (May 15 Ruling) that expanded the scope of this initial phase and provided a short extension to the procedural schedule to consider SCE's May 6 proposal in the hearing process. The May 15 Ruling reiterated the importance of resolving issues related to the allocation of DWR contract volumes. To that end, SCE was directed to:

> "quickly organize and coordinate a series of meetings between the three utilities, DWR, the Commission staff and all interested reviewing representatives of parties who have access to protected information in this proceeding. The purpose of these meetings is to develop, in whole or in part, a proposal, or proposals *to resolve the physical allocation of DWR contracts and MW's between the three utilities….The focus is on the physical allocation and administration of the DWR contracts, not on the revenue requirement.*"[3]

[3] Assigned Commissioner's and Administrative Law Judge's Ruling Changing the Procedural Schedule for Testimony and Hearing in Response to Southern California Edison Company's Motion of May 6, 2002, May 15, 2002, pp. 5-6 (emphasis added).

The utilities did not submit this information in their May 24, 2002 supplemental testimony. Instead, they requested additional time until July 15, 2002 to develop proposals for a physical allocation of DWR contract quantities.[4] The extension was granted and a schedule for written comments on the utilities' proposals was established by ALJ ruling.[5]

On July 12, SCE (on behalf of the utilities) contacted the assigned ALJ to request an additional week to file their proposals. The utilities stated that such additional time would enable them to submit comprehensive filings addressing contract allocation issues and related DWR coordination and operating agreements, with the potential for a narrowing of disputed issues. The ALJ allowed an extension of four days for the utility and DWR filings until July 19, 2002 and scheduled a workshop on July 26, 2002 to discuss the proposals on the record.[6]

On July 18, 2002, DWR submitted an analysis of several options for allocating the DWR contracts among the utilities. The options reflected scenarios requested by Commission staff, which had previously been discussed with the utilities during informal meetings. PG&E, SCE and SDG&E filed their DWR contract allocation proposals on July 19, 2002. Comments on DWR's analysis of options, the utilities' proposals and the discussion during July 26, 2002 workshop were filed by the utilities, the Office of Ratepayer Advocates (ORA), DWR and

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[4] See the May 24th supplemental testimony of SCE (pp. I-6 to I-8), PG&E (p. S-3.) and SDG&E (p. 2.)

[5] ALJ Ruling dated July 10, 2002.

[6] See Administrative Law Judge's ruling Regarding Recent Electronic Notices to Parties, July 16, 2002.

the California Consumer Power and Conservation Financing Authority (California Power Authority) on July 30, 2002. At the direction of the ALJ, the utilities and DWR addressed an alternate DWR contract allocation scenario in their July 30 filings. Replies were filed on August 5, 2002 by the utilities, ORA and the California Energy Commission.[7]

3. Threshold Issue: Operational or Planning Allocation

The testimony and filings to date identify a threshold issue for our consideration; namely, should the allocation of DWR contract quantities include the allocation of specific contracts to individual utilities, or should DWR continue to perform the scheduling and dispatch functions for its statewide portfolio of contracts. By way of background, we first describe the manner in which these functions are performed today.

Currently, the process begins with the utilities submitting to the California Energy Resource Scheduling group at DWR (referred to as "CERS") their net short forecast for the day, as well as a seven-day rolling forecast. CERS fills the net short using the following procedures: First, CERS uses the energy available under DWR's must-take contracts to meet the utilities' forecasted net short positions. If there is remaining net short, CERS evaluates whether it is economical to dispatch energy available under the dispatchable DWR contracts by comparing the market price of power to the variable cost of the dispatchable contracts. If it is economic, CERS will dispatch the required energy from existing

[7] In its comments, the California Energy Commission makes recommendations concerning the timing of the issuance of our contract allocation decision, and other procedural and scheduling matters, but does not address the specific allocation of DWR contracts proposed by parties in this proceeding. Therefore, we do not discuss these comments any further in today's decision.

dispatchable contracts. If not, CERS will purchase spot power from the market. If CERS finds that its existing must-take contracts exceed the utilities' net short forecast, it will sell the excess must-take power into the market. Similarly, if it determines that it is economic to dispatch available capacity for sale into the market, it will do that as well.

CERS then submits a trade schedule to the California Independent System Operator (ISO), indicating that CERS is "sending" a specific amount of energy to each utility. The utilities submit a comparable trade schedule to the ISO to indicate that they are "receiving" the same amount of energy from CERS. These trade schedules are referred to as a Scheduling Coordinator to Scheduling Coordinator ("SC to SC") Trades. If additional spot purchases are necessary or if it is economic to dispatch and sell excess capacity, CERS and the counterparties to these transactions will separately send similar trade schedules to the ISO indicating the amount of energy purchased or sold.

The allocation approach contemplated by the April 2 Scoping Memo, and referred to in this decision as the "operational approach," is to allocate specific contracts to the utilities to manage as an integral component of their resource portfolios. Under this allocation paradigm, the involvement of DWR, through CERS, in day-to-day scheduling and dispatch would disappear. The utilities would assume these functions for the existing DWR contracts, just as they would continue to schedule and dispatch utility resources and assume similar functions for new purchases.[8]

ORA, SDG&E and PG&E recommend that the Commission allocate DWR contract quantities for planning purposes only, that is, for the purpose of

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[8] See July 26, 2002 Workshop, Reporter's Transcript (RT), p. 101.

determining the amount of resources that each utility should procure in the marketplace. Under this allocation paradigm, referred to as the "planning approach," DWR would continue to administer and dispatch the contracts in a single statewide portfolio, similar to the manner described above. A certain amount of DWR's contract energy would be *made available* to each of the utilities in estimating their residual net short for procurement planning purposes. However, in practice, the utility would have the option of utilizing less than its allocated share, and the operational decisions for the contracts (e.g., dispatch and sales of surplus) would continue to be made by DWR. As PG&E explains:

> "Under our proposal, DWR remains responsible for the operation of the contract….That is, all the available energy from each contract is allocated on a pro rata basis to each of the utilities. So, in essence, you can view it as a slice of each contract is available to each utility.
>
> "Then, in the day-ahead market, the utility will give to [DWR] an estimate of the open position, which includes all the energy that we could absorb, given our load and the remaining resources we have available to us, and any energy that is economically used of the contracts. That is, the contract has a certain variable cost, and we will compare that variable cost against the market price. If the variable cost is lower, then we will take the energy…if it isn't then we would leave the surplus for [DWR] to dispose of."[9]

In further support of the planning approach, SDG&E and SCE argue in their transition briefs that the Commission is prohibited by law from allocating specific contracts to the utilities: "ABX1-1 provides that DWR retains title to the energy it sells to the customers of SCE and the other utilities. (ABX1-1. Water

[9] *Ibid.* p. 102.

Code Section 80110.) As such, DWR's contract energy cannot be allocated to SCE or the other utilities, as the [April 2 Scoping Memo] seems to imply."[10]

We disagree. The established practices by which DWR and the utilities have implemented ABX1-1 belie SCE's contention. DWR contract energy is presently allocated daily to SCE and the other utilities via "SC to SC" trades, as described above.[11] Under current practice it is ultimately the utility that schedules DWR contract energy with the ISO following the SC to SC trade, and it is the utility that transmits and distributes the DWR contract energy to its ultimate users.[12] Consistent with ABX1-1, DWR retains title to the energy notwithstanding the fact that the energy is traded to and distributed by the utilities under the Scheduling Arrangements.[13] There is, in short, ample precedent for title to energy remaining with one entity while another trades, or schedules, or otherwise disposes of the energy. Under ABX1-1 the utilities can and do accept allocation of DWR contract energy on an hour-by-hour basis. The

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[10] Brief of SCE on Transitional Issues, April 12, 2002 pp. 20. See also Brief of SDG&E on Transitional Issues, April 12, 2002, p. 4, footnote 1. Apparently, and without explanation, SCE has modified its position since filing the brief and now recommends "that contracts be permanently allocated to the utilities on a contract-by-contract basis." (SCE Reply Comments, August 5, 2002, pp. 3-4.)

[11] See Servicing Agreements (for SCE and SDG&E) and Servicing Order for PG&E, collectively "Servicing Arrangements," at sections 2.2 (a) and (b). D.02-04-047, Appendix B, Attachment A; D.02-04-048, Appendix B, Attachment A; D.02-05-048, Attachment C.

[12] See Servicing Arrangements at section 2.1, which require the utilities "to transmit, or provide for the transmission of, and distribute DWR Power . . ."

[13] See section 2.3 of the servicing arrangements, which provides in pertinent part that "Notwithstanding any other provision [in the servicing arrangements] . . . DWR shall retain title to all DWR Power . . ." where DWR Power is electric power and energy sold by DWR to customers.

requirement of ABX1-1 that DWR retain title to DWR contract energy in no way serves as a bar to allocation of operational control over DWR contract energy.

SCE goes on to argue that "in short, under the current legislative and regulatory framework, DWR cannot allocate energy to each of the utilities as though such energy were a component of each utility's supply portfolio. Instead, each utility will need to verify with DWR on an hourly basis subject to that utility's final acceptance, the amount of energy DWR will deliver to that utility's customers."[14]

The foregoing discussion by SCE appears to be an attempt to reflect current practice under the Servicing Arrangements. We recognize that the Servicing Arrangements will need to be altered to reflect the new operational arrangements that emerge from this proceeding. We expect that DWR will negotiate with SCE and SDG&E appropriate modifications to their respective Servicing Agreements, and DWR will request of us appropriate appropriate modifications to the Servicing Order governing PG&E. We see no element of the "current legislative and regulatory framework" that poses an insurmountable bar to inclusion by the utilities of DWR contract energy in each utility's resource portfolio. We recognize that current practice allows the utilities to dispatch its generating assets and contracts first, prior to calling on any DWR contract energy, but this practice is nowhere legally mandated outside of the Servicing Arrangements, which are within our control and subject to modification as just discussed.

SCE continues that "an equitable methodology needs to be established that provides clear guidelines on how DWR will determine how much energy it has

[14] Brief of SCE on Transitional Issues, April 12, 2002 pp. 22.

available to deliver to each utility's customers on an hourly basis . . . Effectively, DWR's long-term contract portfolio needs to be apportioned to the customers of each utility, and coordinated with each utility's supply portfolio to meet the needs of that utility's customers." We agree with SCE on these points, but fail to see why this need for an equitable methodology is inconsistent with (or a bar to) allocation of DWR contract energy to the utilities for dispatch on a utility portfolio basis. Indeed, working out the particulars of an appropriate prioritization of DWR contracts and utility generating resources and contracts is one of the central issues of this proceeding.

SCE concludes its arguments that contract allocation is illegal with a reference to AB 57.[15] We observe that AB57 currently provides that the utilities have 90 days to prepare procurement plans from the time that the Commission "specifies the allocation"[16] methodology for DWR contract energy. The use of the expression "specifies the allocation" makes it clear that the legislature contemplates – indeed, expects – that DWR contract energy can and will be allocated to SCE and the other utilities, just as the April 2 Scoping Memo implies.

From a policy perspective, we believe that the best way to coordinate DWR and utility resources as the utilities resume procurement is to put all these resources under the dispatch control of the utilities, subject to our oversight. The operational approach to contract allocation achieves this by making the utilities

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[15] *Id.*

[16] "Each electrical corporation shall file a proposed procurement plan with the commission 90 days after the commission specifies the allocation of electricity, including quantity, characteristics, and duration of electricity delivery, to be provided by the Department of Water Resources under its power purchase agreements to the customers of the electrical corporation."

responsible for integrating the scheduling and dispatch of the specific DWR contracts allocated to them with their existing generation assets, contracts and new procurements. As the California Power Authority discusses in its comments, this is the most effective way to ensure that resources are being dispatched in a least cost manner: "The bottom line is that it is a major mistake to split the existing and anticipated contract administration from the continuing utility duty to provide net short procurement."[17]

In contrast, the planning approach perpetuates a two-tiered procurement system in California that was put in place on a temporary basis, and only under emergency circumstances, until the utilities could resume their procurement role. As of January 1, 2003, DWR is no longer in the business of procuring electric power on behalf of SCE, SDG&E and PG&E's customers, and the utilities will resume that responsibility. The operational allocation approach best reflects this reality.

ORA suggests that the Commission consider a transition to operational allocation by adopting a planning approach for 2003, while the Commission further study physical and cost allocation proposals during 2003 and 2004.[18] In ORA's view, this approach would allow the utilities to begin procurement activities without committing them to an inefficient or inequitable permanent physical or cost allocation.

We see little advantage to this approach, and considerable downside to deferring the allocation of contracts. In particular, we are concerned that

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[17] California Power Authority Comments, July 30, 2002, p. 4.

[18] ORA Opening Comments, July 30, 2002, pp. 3-4; Reply Comments, August 5, 2002, pp. 2-3.

deferring contract allocation will necessitate the deferral of residual net short procurement. If we were to adopt a planning allocation for the year 2003 only, we would effectively limit the utilities' procurement authority to a one year period. The utilities have all pointed out that procurement for 2003 needs requires contracting for transactions beyond that a one-year time horizon.[19] Eliminating the utilities' ability to enter into any multi-year transactions may limit both suppliers' interest in utility solicitations and the utilities' ability to acquire the necessary resources at more favorable prices.

For these reasons, we will adopt an operational allocation of DWR contracts, rather than a planning approach. In the following sections, we examine several options for allocating specific DWR contracts to the utilities.

4. Contract Allocation Options and Positions of the Parties

The contract allocation options described below distribute each of the DWR contracts, or specific product components of each contract, among the resource portfolios of PG&E, SCE and SDG&E.

The contracts vary significantly not only in pricing terms, but also in terms of the amount of dispatch flexibility provided. Many contracts specify must-take quantities, and some contracts allow the seller to "put" additional volumes to the buyer. They also differ with respect to delivery points for the purchased power. Some of the contracts require deliveries exclusively to PG&E's service territory north of Path 15, the major transmission tie between northern and southern California. These are referred to contracts having a "NP-15" delivery point.

[19] See July 12, 2002 briefs on transition issues of PG&E, SCE and SDG&E. We are addressing these issues in a separate decision.

Others specify deliveries to points south of Path 15 within the service territories of SCE and SDG&E ("SP-15" delivery point). Several contracts specify separate NP-15 and SP-15 must-take contract quantities. One of the contracts (Sunrise) specifies a delivery point in ZP-26, the third major ISO zone, which is located within PG&E's service territory between NP-15 and SP-15.

Many of the contracts provide for multiple products. Products include baseload "7x24" products, also referred to as "clock hour quantities,"[20] that are designed to deliver energy continuously over a twenty-four hour period, seven days a week. Some contracts include "6 x 16"peaking (or "peak hour") products, which are designed to deliver energy six days per week during the hours from 6 a.m. to 10 p.m. In addition, individual products can be either "must-take" or "dispatchable." A dispatchable product allows the buyer to determine whether or not to dispatch the contract, depending upon need and market prices, while a must-take product does not.

Three of the contracts have delivery optionality, i.e., the seller can specify the delivery points of contract quantities. For the PacificCorp contract, which represents 300 megawatts (MW) of dispatchable capacity, the seller can specify either an NP-15 deliver point or a delivery point at the California-Oregon Border.

The Coral and Sempra must-take contracts are the two largest volume contracts that have delivery optionality, and both continue into the 2011-2012 timeframe. For 2004, the Coral contract specifies that 520 MW out of the total (950 MW) possible quantities delivered under the contract must be delivered into NP-15. This minimum requirement is broken down into "base quantities" (a combination of clock-hour and peak-hour products) and "additional quantities"

[20] RT at 17.

that are peak-hour products. Under the contract, all the peak-hour quantities can be increased or decreased by 10% at the seller's option. The seller can specify a delivery point at any of the three ISO zones (NP-15, SP-15 or ZP-26) for those quantities where a NP-15 delivery point is not specified.[21]

The Sempra contract allows for the seller to specify any of the ISO delivery points for the entire must-take quantities, which total close to 1500 MW at present. Like the Coral contract, it contains a combination of products and contract complexities.[22]

Finally, three of the DWR contracts are between DWR and affiliates of the utilities. The Sempra contract is affiliated with SDG&E, the Sunrise contract is affiliated with SCE, and the PG&E Energy Trading contract is affiliated with PG&E.

In the following sections, we summarize the various options presented in this proceeding for allocating the DWR contracts, and the recommendations of the parties on which option should be adopted.[23]

4.1 DWR's Presentation of Allocation Options

At the request of Commission staff, DWR developed several contract allocation options to serve as the starting point for dialog with the utilities and

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[21] RT at 16-20; CERS Summary Diagram of Written Example Used at July 26, 2002 Workshop, dated July 30, 2002.

[22] See RT at 22 and CERS Contract Allocation Analysis dated August 7, 2002.

[23] The preferred options of ORA, SDG&E and PG&E presented in this section represent their recommendations assuming that the Commission does not adopt a planning approach. As discussed above, these parties prefer that DWR continue to administer the contracts in a statewide portfolio and that contract quantities be allocated for planning purposes only.

interested parties during the discussions contemplated in the May 15 Ruling. The discussions started with DWR presenting a "straw man" allocation that followed the basic allocation guidelines in the April 2 Scoping Memo, and two additional alternatives. This led to further refinements of the options and an update of DWR's analysis of the options using its most recent modeling run, PROSYM Run35.[24] DWR's July 19th filing presents the straw man and four contract allocation options, each representing a different permutation of (1) whether contract splitting is allowed and (2) whether the utility can be allocated a contract with its affiliate. By contract splitting, we refer to situations where a must-take contract includes more than one delivery point for specified contract quantities, and the allocation can be split along those lines for operational purposes.[25] Dispatchable contracts were not considered candidates for splitting.

At the workshop, DWR explained that it developed the specific contract allocations under each option by attempting to balance the energy allocation with the net short energy need for each utility. As a measure of that need, DWR calculated a 7-year average of each utility's net short position. DWR used the PROSYMRun35 for the years 2003 to 2009 that included an estimate of direct

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[24] DWR states that this is the model run it is using to support its 2003 revenue requirements. RT at 24.

[25] For example, the El Paso contract is a 50 megawatt (MW) 6-by-16 product that has 50 MWs delivered in the north and 50 MWs delivered in the south. Assuming that PG&E would be allocated the northern portion and SDG&E the southern portion, each utility could submit separate schedules for their allocated quantities to the ISO. In the alternative, either PG&E or SDG&E could submit schedules on behalf of both. Each would determine the need for or excess of the allocated contract quantities, and handle those decisions operationally as if each held an individual contract. RT at 9-11.

access migration.[26] The following average net short for each utility, as a percentage of total net short, result from DWR's calculations: 41% for PG&E, 40% for SCE and 19% for SDG&E.

Although DWR considered the energy allocation relative to the utility's net short position in developing each of its contract allocation options, DWR did not present any recommendations regarding which allocation should be adopted by the Commission. Instead, DWR provided for the Commission's consideration several comparison metrics in tabular and graph format for the options it analyzed, as well as for other options presented in this proceeding. These include: (1) allocated energy as a percentage of total contract energy, (2) allocated capacity as a percentage of total contract capacity, (3) residual net short as a percentage of utility load, (4) must-take surplus as a percentage of utility load, (5) contract costs, on a dollar and per MWh basis if costs follow the contract and (6) contract costs, on a dollar and per MWh basis if costs are allocated on a fixed $/MWh basis.

The utilities have used the DWR allocation options as a starting point and refined the "no affiliates" options to develop their preferred scenarios. They modify the specific contract allocations under these options based on delivery point and operational considerations, as well as additional cost metrics they take into consideration. Because DWR's options have met their intended purpose -- to initiate the dialog among parties and present comparison information for our consideration -- we need not consider the specific contract allocations presented in those options any further. Rather, we focus on the refinements discussed

[26] RT at 24, lines 6-10.

below and the metrics that DWR has developed to facilitate a comparison among proposals.

4.2 SCE and SDG&E's Preferred Allocation

SCE and SDG&E have reached consensus on a proposal for allocating the DWR contracts. Their preferred allocation of contracts is presented in Attachment 2. As described below, SCE and SDG&E reach the same result for somewhat different reasons.

SCE takes the position that contract allocation should be based on sharing above-market costs in proportion to the net-short position of each utility at the time DWR entered into the contracts, i.e., during the 2001-2002 timeframe. In SCE's view, current data indicates that PG&E is responsible for 46% to 48%, SCE for 35% to 38% and SDG&E for 14% to 19% of the net short during that period.[27]

SCE developed its preferred allocation of contracts in four general steps. First, SCE looked at the forward market prices ("forward curve") for each product in each DWR contract, over the term of the contract. Second, SCE calculated the difference between the contract price and the forecasted market price for each product (and contract) to derive the above- market cost (or "burden") of all DWR contracts. Third, SCE applied the net-short percentages described above to determine the above-market burden that should be allocated to each utility. Finally, SCE "mixed and matched" the various contracts assigned to each utility, taking into consideration certain operational factors such as the delivery points specified in the contract, until it arrived at a solution that approached this allocation of above-market burden.[28]

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[27] SCE's July 19, 2002 filing, pp. 17-18. See also, RT, Attachment C, p. 8.

[28] RT at 92.

As a starting point, SDG&E takes the position that the allocation of contracts should (1) reflect circumstances that existed at the time original DWR commitments were undertaken and (2) be consistent with the allocation of costs that are embedded in present rates to customers. To SDG&E, this means that an approximate 16% share of contract energy (as a percentage of the total DWR portfolio) should be allocated to SDG&E. SDG&E further argues that a historical framework for determining what percent of "the pie" that each utility gets is particularly appropriate for SDG&E, since it has no hydro and the contracts were purchased in a low hydro year.[29]

In addition to taking into account the overall energy allocation as well as specific operational characteristics of the contracts, SDG&E evaluated the allocation options in terms of the "all-in" costs of the contracts to its ratepayers. SDG&E's definition of all-in costs includes DWR contract power costs, residual net short procurement costs and the impact of excess must-take power sales.[30] "Residual net short" refers to the power that the utility still needs to procure to meet loads after DWR contract quantities are allocated. It other words, it is the "net short," less those quantities.

To develop the all-in cost metric, SDG&E first calculated an average contract price based on the energy and capacity costs of the contract, similar to the contract cost metric prepared by DWR.[31] SDG&E then adjusted this number

[29] RT at 93.

[30] SDG&E does not include in its calculation of all-in costs any revenues from sales associated with the economic dispatch of surplus capacity.

[31] However, SDG&E's average $/MWh contract cost calculations cannot be directly compared to DWR's "contract costs assuming cost following contract" numbers because SDG&E averages over a 5-year subset of the 7-year period that DWR uses.

to reflect the cost of buying the residual net short on its system and the impact of selling excess must-take power sales. The all-in cost rate in $/MWh is determined by dividing the contract costs and residual net short costs (net of surplus sales revenues) by the total net short energy requirement.[32] SDG&E's preferred contract allocation, which is identical to SCE's proposal, minimizes the all-in costs to its ratepayers.

4.3 PG&E's Preferred Allocation

PG&E recommends that if the Commission pursues contract-by-contract allocation, the Commission should take a "rough justice" approach and consider a zonal allocation of power based on delivery point. Under this approach, PG&E would take scheduling and dispatch responsibility for those contracts which have NP-15 as their primary delivery point, and contracts with SP-15 delivery points would be allocated to the southern utilities.

The key consideration for PG&E, however, is that its customers should be required to take no more than their pro rata share of DWR power, based on future need. PG&E calculates each utility's pro rata share as an average of the net short projected under DWR's PROSYMRun35 for the years 2003 to 2009. In all but one respect, PG&E's calculation of the 7-year average net short is the same as DWR's calculation. While DWR takes into account expected direct access migration in the future, PG&E uses the PROSYMRun35 that ignores such migration in deriving its pro rata share. PG&E contends that this approach is the most consistent with the principle that DWR contracted power for the future needs of all utility customers, but at the time it did so, could not have anticipated the level of migration from utility loads due to direct access.

[32] RT, p. Attachment B, p. 4.

PG&E's calculations produce an average pro rata share of future net short of 40% for PG&E, 44% for SCE and 16% for SDG&E. PG&E's preferred contract allocation, which results in an allocation of 38% of contract energy to PG&E, is presented in Attachment 2.

4.4 Additional Options Prepared at the Direction of the ALJ

As discussed at some length during the July 26 workshops, the contract allocations preferred by PG&E and jointly by SCE/SDG&E differ only with respect to two contracts: Sunrise and Coral. At the close of the workshops, the ALJ directed the utilities to present permutations to their proposed Sunrise and Coral allocations, as follows:

> "(1) Allocate all of Coral to PG&E and all of Sunrise to SDG&E/SCE. In doing so, SDG&E and SCE may rebalance the mix of the SP-15 contracts they allocated between them in their July 19 proposals in making this modification. However, dispatchable contracts (such as Sunrise) should not be split. If the rebalancing between SDG&E and SCE would now involve allocation of an affiliates contract or portion thereof to either of them—they should discuss why this exception is warranted. Do not modify any NP-15 allocations to PG&E.
>
> "(2) [L]ook at an alternative that instead of Sunrise being allocated to SCE/SDG&E, a comparable shift of contract quantities was accomplished by an alternate split of the Coral contract. This additional permutation is optional. No others should be submitted."[33]

SCE and SDG&E jointly submitted the permutation described in (1) above (referred to as the "ALJ alternate"), along with the comparison cost metrics they presented for their July 19, 2002 filings. They mutually agreed to a rebalancing

[33] Electronic ruling from ALJ to parties summarizing her direction to parties, July 26, 2002 at 6:35 p.m.

of the allocation of contracts between them from their July 19 filings in presenting this permutation. PG&E also evaluated the ALJ alternate. All three utilities continue to argue in favor of their preferred allocations described above.

In particular, SDG&E argues that it should not be allocated Sunrise because (1) the contract specifies a ZP-26 delivery point that is not in SDG&E's service territory and (2) the transmission route to deliver power from ZP-26 to SP-15 has historically been congested. In addition, SDG&E objects to this permutation on the grounds that it produces a distinctly worse result for its customers in terms of cost burden and energy allocation than its preferred option. SCE objects for similar reasons.

PG&E argues against the ALJ alternate on different grounds: PG&E believes that the allocation of Sunrise to SDG&E/SCE and all of the Coral contract to PG&E results in a disproportional amount of energy being allocated to PG&E's customers in 2003 (i.e., 45%).[34] Consistent with the ALJ's directions, PG&E presents an additional permutation whereby Sunrise energy remains with PG&E, and the Coral contract power is split by moving the clock-hour and peak-hour base quantities to SDG&E and SCE. Under this scenario, PG&E's customers would receive about 40 percent of the energy available under the DWR contracts between 2003 and 2009, which PG&E argues is more equitable based on its pro rata share of future net short.

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[34] PG&E also presents a modification of this permutation that allocates (in addition to Sunrise), the Allegheny 2, Constellation-Produce and El Paso NP 15 deliveries to SDG&E and SCE. We agree with SCE and SDG&E that PG&E violated the ALJ's direction regarding the scope of additional scenarios, and do not consider this permutation any further.

SCE objects to this permutation on the grounds that it shifts proportionately too much above-market costs to SCE's ratepayers and would impose, combined with the allocation of the Sempra contract to SCE's customers, too much delivery risk. SDG&E objects for similar reasons.

4.5 ORA's Position

In concurrence with the utilities, ORA supports the principle that contracts should not be assigned to a utility that is an affiliate of the contracting party. ORA also supports PG&E's use of a multi-year forecast of net short, rather than a recent base period, as the benchmark for allocating contracts. In ORA's view, allocation based on system needs going forward will minimize costs.

In terms of the allocation of specific contracts, ORA supports the allocation of Sunrise to SP-15 to SDG&E under the ALJ alternate. ORA prefers this allocation to splitting the Coral contract because, in ORA's view, doing so would violate delivery point principles for contract quantities that are designed for NP-15 delivery.

5. Adopted Contract Allocation

Despite the different allocation principles and comparison metrics advocated by the parties, the preferred contract allocations presented by PG&E and (jointly) by SCE and SDG&E are identical in more respects than they are different. First, neither proposal allocates power to a utility from a contract of its affiliate. Second, the proposals reflect consensus that separately identifiable products in a contract can be split, but that dispatchable products should not be split. Third, the utilities' preferred allocations generally put all contracts with NP-15 specified delivery points with PG&E, and all those with SP-15 specified delivery points with SDG&E.[35] In fact, *with the exception of only two of the contracts (Coral and Sunrise), the utilities' preferred contract allocations are identical.* (See Attachment 2.)

Under the SCE / SDG&E joint proposal, both the Coral and Sunrise contracts are allocated to PG&E. Under PG&E's proposal, Sunrise is allocated to southern California (PG&E does not specify any allocations between SCE and SDG&E), and Coral is split between PG&E and southern California. PG&E proposes a split whereby 25% of the base and additional quantities are allocated to PG&E, with the remainder going to the south.

Each utility urges us to resolve this remaining allocation issue by selecting the allocation principles and comparison metric that it prefers to the exclusion of others. In doing so, we would need to select from among the following a single yardstick to use in measuring the results of each allocation option: (1) a current base period of net short, (2) a projection of net short into the future including estimates of direct access migration, or (3) a projection of net short excluding direct access migration. Attachment 3 compares the net-short yardsticks presented in this proceeding.

Once the yardstick is selected, the utilities would then have us choose the single most appropriate metric with which to measure the results of each allocation option: Should it be the quantity of power allocated to each utility, as PG&E prefers? Should it be the above-market costs that SCE calculates, or should we utilize the all-in costs that SDG&E measures? And how should the residual net short and other metrics that DWR developed be considered?

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[35] The only exception is PG&E's treatment (split) of the Coral contract, as discussed further below.

We do not believe that such an approach is appropriate, or necessary, to resolve the issues in this proceeding, for two major reasons. First, there appears to be no single, clear cut "right" framework for considering contract allocation proposals, or an ideal companion comparison metric. Take the issue of the net-short position. SCE and SDG&E argue that the only legitimate perspective is one that looks at the net-short of the utilities during the 2001-2002 period because that is the net-short position DWR was trying to fill when it entered into the contracts. There is some merit to this perspective to the extent that DWR may not have anticipated direct access load migration at that time, or taken into account other factors that now lead it to project significant changes to the net-short positions of the utilities in the coming years.

However, under this approach, SCE and SDG&E make the questionable assumption that DWR entered into long-term contracts without any consideration of future net short needs or longer-term hydro conditions. Moreover, eliminating any consideration of future net-short needs ignores the potential impact of contract allocation decisions on the utilities' ability to actively participate in the procurement process as they resume that responsibility. In fact, we observe that forecasts of residual net short must have been at least implicitly considered by the utilities, since each utility ended up proposing an allocation that gave it the highest residual net short percentage relative to any of the other allocation options.[36] (See Attachment 4.)

SCE urges us to reject any allocation principle that utilizes a forecast of net short, arguing that there is too much forecasting error contained in such

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[36] The only exception to this observation is SCE's proposal when compared to the DWR options that would allow affiliate contracts. See RT at 44-45.

projections. In particular, SCE argues that the PROSYMRun35 is not consistent with SCE's forecast of net short over the next seven years, has not been examined in a Commission proceeding and is likely to be the subject of contentious disputes over accuracy when it does come before the Commission in DWR's revenue requirements proceeding.[37] SDG&E also argues that DWR's forecast of net short contains inaccurate assumptions.[38]

However, one could argue that the above-market cost metric, which SCE asks us to rely on in determining the ultimate reasonableness of contract allocation proposals, suffers from similar shortcomings. SCE's calculations of above-market costs, which first appear in this proceeding on July 19, 2002, have not been scrutinized by parties or ultimately adopted as reasonable in any Commission proceeding. In fact, SDG&E states that it did not even review SCE's calculations as it developed the joint proposal.[39] SCE's methodology relies on several calculations and projections that are based on subjective assumptions, including a forecast of future market prices (forward price curve) based on broker quotes and (after 2007) growth rate assumptions, and calculations of future hourly market prices that are derived from a regression analysis of the forward price curves and historical market prices.

Despite SCE's suggestion that the above-market cost metric is immune from forecasting inaccuracies, because the relative proportion of above-market costs among contracts do not depend upon the absolute level of the market price

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[37] RT at 87; SCE's July 30, 2002 comments, pp. 8-10; SCE's August 5, 2002 Reply Comments, pp. 11-13.

[38] SDG&E's July 30, 2002 comments, pp. 3-4.

[39] RT at 59.

projection,[40] a closer examination of SCE's workpapers indicates that this is not the case. Under SCE's methodology, changes to the projection of forward prices will impact the relative amount of power dispatched from dispatchable contracts, vis-à-vis the must-take contracts. This, in turn, can alter the relative level of contract costs (and resulting proportion of costs above market) among dispatchable and must-take contracts. In this way, the results of SCE's above-market cost calculations are, in fact, sensitive to market price assumptions.

In sum, one reason to reject the notion of selecting a particular contract allocation approach over another is that there is simply no clear "winner" in the bunch. The second reason to reject this notion is that the proposals appear to be driven exclusively by the *results*, rather than by a commitment to underlying allocation principles. Had the reverse been true, one would expect to see some mixed results under the utility's preferred allocation in terms of the various comparison metrics presented in this proceeding.

However, as can be seen from the comparison tables presented in Attachment 4, PG&E's preferred allocation results in the lowest allocation of estimated costs to its customers, irrespective of what other proposal it is compared against or which cost metric is used.[41] Similarly, PG&E finds itself

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[40] RT at 87-88.

[41] We do not present the all-in cost metric prepared by SDG&E in these tables because SDG&E submitted its analysis and the $/MWh results under seal. We presume this is because the calculations require the use of information regarding SDG&E's residual net short quantities and other information that SDG&E considers confidential. For similar reasons, SDG&E did not prepare all-in costs for SCE and PG&E, and SCE and PG&E indicated during workshops that they could not reproduce SDG&E's results for their systems without a delay in the schedule. Therefore, even if SDG&E's numbers were not under seal, we do not have a utility-by-utility comparison of this cost metric, by allocation option, as we do with the other cost metrics presented in this proceeding.

Footnote continued on next page

with the least amount of contract energy and capacity allocated to its portfolio (and, correspondingly, the largest residual net short) under its preferred option, relative to all others. As a direct corollary, SCE and SDG&E are allocated the highest costs under any of the cost metrics, the most contract energy and capacity (and left with the lowest residual net short) under PG&E's proposal.[42] It is not surprising to see similar results (in reverse) under SCE's and SDG&E's preferred contract allocation.

In sum, despite the very detailed arguments of each utility on why we should use a particular set of principles and methods for allocating the DWR contracts, the record in this proceeding indicates to us that those principles and methods were in fact developed to justify a specific set of results. Moreover, as discussed above, selecting a single allocation methodology as the ideal approach ignores the fact that the various allocation principles and associated comparison metrics presented in this proceeding have disadvantages when considered in isolation.

Instead, we will allocate Sunrise and Coral in a manner that strikes an appropriate balance between the competing proposals of PG&E and SDG&E/SCE and the various principles and comparison metrics considered. We

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However, based on our review of the calculations that SDG&E did provide in its filings, SDG&E's all-in costs are minimized under the same scenarios for which the other cost metrics are lowest for SDG&E, and vice versa. We therefore expect that the relative position of each utility with respect to all-in costs, had they been provided, would correlate with the other cost metrics in a similar manner.

[42] There is less of a direct pattern to the results in terms of the must-take surplus, i.e., the utility's preferred scenario does not systematically result in the lowest surplus amounts relative to all other options that were considered in this proceeding. However, the utilities' preferred allocations do maintain the must-take surplus within a relatively low (2-4%) range.

believe that the ALJ alternate that allocates the Sunrise contract to SDG&E and the Coral contract to PG&E strikes such a balance, for several reasons.

First, despite the utilities' objections to this alternate, the results of such an allocation do reach a reasonable middle ground between the utilities' proposals with respect to the comparison metrics and net-short calculations considered in this proceeding. This can be seen by examining the tables in Attachment 4.

Whereas PG&E's proposal would result in a 38% share of contract energy (37% share of capacity) allocated to its portfolio, and SCE's proposal would allocate to PG&E a 44% share of energy (47% share of capacity), the ALJ alternate results in a 41% share of energy (43% share of capacity) going to PG&E. In terms of SCE's above-market cost metric, PG&E would be allocated 42% of the above-market costs calculated by SCE under the ALJ alternate, compared to 37% under its own proposal and 48% under the joint proposal of SCE and SDG&E. The contract costs (assuming either a pro rata or cost following allocation) for PG&E under the ALJ alternate also fall between the two utility proposals. The ALJ alternate results in an allocation to PG&E of 7% of the total residual net short, compared to 10% under PG&E's proposal and 4% under the SCE/SDG&E joint proposal.

Similarly, the ALJ alternate finds a middle-ground with respect to the allocation of power, cost and residual net short for SDG&E and SCE, as well. The ALJ alternate also produces results for the allocation of contract power and above-market costs that fall within the range of net short calculations presented in this proceeding as the yardstick for evaluating allocation options. This can be seen by comparing the percentage allocations associated with the ALJ Alternate in Attachment 4 for "allocated energy," "allocated capacity" and "allocated above-market costs" with the range of net-short percentages presented in Attachment 3.

Second, the ALJ alternate reaches an appropriate balance in allocating contracts among the utility portfolios that involve some delivery uncertainties. SCE is allocated the Sempra must-take contract, which has delivery point optionality for approximately 1500 MW. PG&E is allocated the must-take Coral and dispatchable PacificCorp contract quantities with delivery point optionality for combined total of 820 MW. SDG&E is allocated the dispatchable Sunrise contract (560 MW) with a delivery point in ZP-26, north of Path 26. For all three utilities, there may be potential transmission bottlenecks during certain times of the year in delivering power from these contracts to their service territories. However, in our judgment, the ALJ alternate allocation spreads the delivery risk associated with these contracts more equitably among all three utilities when compared to the utilities' proposals.

Third, the ALJ alternate also reaches a reasonable outcome in terms of SP-15 and NP-15 zonal allocation: PG&E takes scheduling and dispatch responsibility for all quantities that have NP-15 specified delivery points, and contracts with SP-15 specified delivery points are allocated to the southern utilities. This allocation of responsibility avoids necessitating an inter-zonal transfer or a sale of these quantities if a transmission path is congested.

In contrast, both PG&E's preferred proposal and the permutation of the Coral split that PG&E presented in its July 30 comments would allocate a significant portion of the Coral contract quantities designed for NP-15 to the south. Under PG&E's preferred proposal, where 25% of the base and 25% of the additional quantities are allocated to PG&E with the rest going south, a total of up to 288.75 MW designated for NP-15 delivery would be allocated to SDG&E and SCE. Under the permutation that PG&E developed in response to the ALJ's ruling, where all base quantities would go south, 125 MW of NP-15 designated quantities would be allocated to SDG&E and SCE.[43] Moreover, as SCE points out, the complexities of the Coral contract make it an undesirable candidate for splitting.

And finally, the ALJ alternate produces a resolution of the issues without requiring any utility to manage the contract of its affiliate. While our Affiliate Transaction Rules do not prohibit such an arrangement and provide sufficient safeguards against self-dealing and other potential market abuses, a contract allocation approach that does not create a utility-affiliate relationship simplifies our task in overseeing the administration of such contracts.[44]

For these reasons, we adopt the allocation of DWR contracts under the ALJ alternate, as presented in Table 1.

The utilities urge us to specify in advance a trigger that would initiate either a reconsideration of the physical contract allocations we adopt today, or a financial adjustment to the allocation of DWR's revenue requirement among the

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[43] RT at 21. CERS Summary Diagram of Written Example Used at July 26, 2002 Workshop, dated July 30, 2002. The Coral contract specifies that the entire 350MW of "additional quantities" are to be delivered to NP-15. 75% of the additional quantities equal 262.5 MW. In addition, the seller may increase/decrease all capacities a year by 10%. 75% of this "put" option equals 26.25 MW, for a total of 288.75 MW of NP-15 quantities going to the south under PG&E's preferred allocation.

The contract also requires a minimum of 25% of the 500 MW in base quantities to be delivered to NP-15, so PG&E's alternate permutation would send 125MW of NP-15 designated quantities to the south.

[44] All interactions between a utility and its affiliates are subject to specific rules addressing nondiscrimination, disclosure and information, and separation. In particular, the rules generally require that all transactions between a utility and its affiliates be conducted at arms-length. (See D.97-12-088, Appendix A.)

utilities.For example, SCE recommends that we establish a trigger to reallocate the DWR revenue requirement among utilities if restructuring of any contract changes the above-market cost by the greater of 10 percent of the original contract's above-market costs, or $10 million. Under SCE's proposal, the Commission would reallocate the resulting change in above-market costs equitably among the utilities in proportion to the share of above-market costs associated with today's adopted contract allocation. PG&E proposes a trigger that would adjust the physical contract allocation adopted today based on an energy threshold, in the event of either contract restructuring or termination. SDG&E draws from PG&E's and SCE's proposals and recommends a trigger mechanism that is based on changes to the amount of energy, capacity or above-market costs.[45]

We do not adopt any of the utilities' proposals for a trigger mechanism. As discussed above, we believe that the best way to coordinate DWR contracts with utility resources is to put them in the utilities' resource portfolios to be scheduled and dispatched by the utilities. This decision, along with a decision on the utilities' procurement plans, will enable the utilities to move forward with their procurement planning and determine the appropriate combination of long-term and short-term energy and capacity needed to meet their individual residual net short requirements.

In our view, adopting an advance trigger mechanism to reconsider the contract allocation we adopt today would insert an unacceptable level of additional uncertainty and complexity into the procurement process going

[45] SCE's July 19, 2002 comments, pp. 27-29. PG&E's July 30, 2002 comments, pp. 7-8; SDG&E's August 5, 2002 comments, pp. 11-12.

forward. If a DWR contract were renegotiated and the trigger criteria were met, each utility would be placed in the position of trying to plan for future needs not knowing which DWR contracts might be removed from its current portfolio, added from another utility's portfolio, or a combination of both. Until the Commission took final action in response to the "triggered" reallocation proceeding, this uncertainty would persist. Based on our experience with the contract allocation process to date, revisiting this issue would take a significant amount of time and resources. Moreover, any such future reallocation process would be further complicated by the fact that the utilities would already have made procurement decisions and commitments based on the allocation we adopt today. While SCE's proposal to establish a financial adjustment trigger appears to avoid these particular problems, it relies upon an above-market cost metric (both in the trigger and response) that has not been carefully scrutinized or adopted by the Commission.

6. DWR Contracts, Economic Dispatch and Cost Allocation Issues

As described below, under the existing two-tiered procurement system in California, the utilities dispatch their own generating assets and contracts first to determine their net short position, and DWR dispatches its contracts and procures additional resources as necessary to meet the combined net short of all three utilities. This changes with the allocation of specific DWR contracts to each utility as they resume their procurement responsibilities. Now each utility must operate with a resource portfolio that includes (1) its own generating assets and existing power contracts, (2) the must-take and dispatchable DWR contracts allocated today, and (3) new resources that it procures in the market.

Least-cost or "economic" dispatch should be the operating rule for the utility's portfolio of resources, including the DWR contracts. All parties agree with this policy, in concept. However, SCE and SDG&E argue that the total costs of the DWR contracts must follow the allocation of contract power for operational purposes in order to achieve an economic dispatch.

We disagree. Economic dispatch entails analysis of the marginal costs of the available energy and dispatching the least-cost incremental resource. An important element of least cost dispatch is that the fixed costs associated with resources are considered sunk for dispatch purposes. Variable costs are the only ones that are incurred or avoided as a result of operating decisions. As DWR, ORA and PG&E point out, to achieve economic dispatch the operating utility needs only to see the variable costs of each DWR contract (or of any other resource in its portfolio).[46] We agree with PG&E's observation that "[d]ispatch and operation of the DWR contracts does not require the allocation of total costs, any more than a utility requires the consideration of its total costs to dispatch its own utility retained generation."[47]

Our allocation of DWR revenue requirements may or may not assign the total costs of each contract to the utility to which that contract is allocated. We leave that issue open to be decided when we have all the relevant information concerning DWR's total revenue requirements and can carefully examine cost allocation alternatives. However, based on the record in this proceeding, we believe it is reasonable to require that the variable costs of each contract follow contract allocation. This will ensure that utility dispatch decisions are based on the appropriate operating cost information. Accordingly, in developing its

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[46] RT at 43, 80, 120, 130-131, 140. ORA's July 30, 2002 Comments, p. 8.

[47] PG&E's August 5, 2002 Comments, p. 5.

revenue requirements proposal, DWR should present a contract-by-contract delineation between fixed (or sunk) and variable costs for our consideration.

In its comments, DWR proposes that we establish a dispatch priority for the utility's portfolio whereby the DWR must-take contracts would be dispatched first under all circumstances.[48] In essence, DWR is asking that these contract quantities be first in line to be sold to the utility's customers, and last in line for any reductions in output or sales of surplus energy in the market.

DWR's position stems from its concern that the actual revenues from contract quantities will not match its revenue requirement projection for ratemaking purposes, unless such a priority is given.[49] DWR's revenue requirement consists, in large part, of DWR's forecast of the cost associated with the long-term contracts, taking into account forecasts of the utilities' load and the fixed and variable costs of the contracts that will be dispatched to meet those loads. The revenue requirement also takes into account a forecasted amount of revenues from system sales of surplus capacity. The rate that DWR is authorized to charge utility customers is calculated by dividing the authorized revenue requirements by the expected sales to utility customers. If actual sales to DWR customers are less than projected (either because output from the contracts is less than forecasted or because more sales of surplus energy takes place than projected, or other factors), DWR will not recover its forecasted revenue requirement with the authorized rate, and may need to return to the Commission to request a higher average rate.

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[48] Additional Comments of DWR, July 30, 2002, p. 2.

[49] See RT at 110-111, 135-136.

In our view, the utilities' dispatch protocols should not be driven by considerations of whether or not DWR will end up with a higher or lower computed average rate. At the end of the day, as SCE points out, DWR will collect its revenue requirement.[50] However, under certain circumstances, economic dispatch will mean supplying incremental power from lower-cost utility generating assets to customers, even if this means that DWR contract power is to be sold on the market at a "loss." This is exactly the kind of balancing that must be performed in determining least cost dispatch. Therefore, we believe it is inappropriate to establish the dispatch priority that DWR recommends.

7. Treatment of Revenues from Sales of Surplus Energy

When the utilities resume the net short procurement function, there will be hours, particularly in the off-peak period, when each utility is long energy on a portfolio basis and will have to make system sales. As SCE explains:

> "The reference point is the market price for power…. If the plant costs $20 a megawatt hour to operate and the market price is above that, then the plant will operate regardless of whether that power is needed to meet load or not. So we dispatch, as a first step, the generation against the market price. Then the next step is to look at how much generation we have relative to the load, and we're either long or short. At that point, if we're short, we need to buy additional power. If we're long, there needs to be a sale from the portfolio."[51]

At the time the sales are made, or decisions to back down resources are considered, the utility should perform such actions in a least-cost, economic

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[50] RT at 116-118.

[51] RT at 109.

manner. As discussed during workshops and subsequent comments, there is one additional step that needs to be taken after these decisions are made, i.e., the revenues resulting from sales of excess power must be credited to the corresponding revenue requirement.[52]

To do this, an accounting protocol needs to be established to determine whether these revenues (or what portion thereof) were generated from DWR contract quantities or from the utility's other resources. Prior to electric industry restructuring, there was no need to determine the source of the sale, because all revenues (retail sales to customers or sales of surplus power on the market at wholesale) from the utility's portfolio were credited to the revenue requirement of the utility. And during the time that DWR has been procuring electric power on behalf of utility customers, all sales have been made from DWR's contract portfolio and credited to its revenue requirement. However, with the allocation of DWR contracts to the utilities and their return to procurement activities, an accounting protocol now needs to be established to apportion the portfolio sales revenues between DWR and each utility that makes the sale.

In its July 30 comments, SCE reiterates a recommendation that it submitted with its procurement plan.[53] Specifically, SCE recommends a protocol that would establish the following hierarchy to account for the sales of surplus power: (1) sales are first attributed to quantities dispatched from the utility's new supply obtained after it resumes procurement, (2) sales are next attributed to quantities dispatched from DWR contracts, and finally, (3) sales are attributed

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[52] See RT at 110-112, 116-117.

[53] Exhibit 1, "Volume I, Southern California Edison Company's Testimony on Procurement Issues," pp. IV-8 to IV-10. See also RT at 112.

to the utility's existing supply resources. SDG&E endorses this hierarchy in its August 5 reply comments, and recommends that it be extended to curtailments of must-take contract quantities. Both argue that this hierarchy is reasonable because it reflects the sequence with which the various resources were acquired. PG&E prefers that this issue be deferred to DWR's revenue requirements proceeding.

While there is some appeal to SCE's and SDG&E's logic based on the sequence of historical events, their proposal imposes an artificial hierarchy to dispatched quantities, based on the timing of resource acquisition, that does not represent the way retail load is served or surplus power sales are generated in an integrated utility portfolio. As described above, the utility will now dispatch all of the must-take quantities in its portfolio (including must-take DWR contracts) plus all of its dispatchable resources up to the market price for each product. Contrary to SDG&E's suggestion,[54] there is no need to establish a sequential protocol for dispatch and curtailment among must-take contracts: By definition, the utility will need to "take" (dispatch) all of those quantities and then determine whether it makes more economic sense to sell excess power from its portfolio, ramp down utility-owned generating plants, or take some combination of these and other actions based on least-cost economic dispatch if it finds itself in a long position.

We prefer to account for sales revenues in a manner that better reflects the procurement process described above. 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.

[54] SDG&E's August 5, 2002 Reply Comments, pp. 4-6.

Accordingly, we will prorate sales revenues between the utility's revenue requirements and DWR's revenue requirements based on the relative quantities dispatched from utility generating assets (including contracts and market purchases in the future) and the DWR contracts.

In its comments on the proposed decision, DWR suggests that this approach to accounting for surplus sales revenues (and the corollary, for revenue from retail customers, or "remittances") will have the unintended outcome of creating a higher utility pro rata share of remittances at the expense of DWR's revenue requirement stream. DWR recommends that the pro rata protocol be modified to specify that all must-take resources are considered to first serve retail load, based on available contract capacity.

In effect, DWR is asking us ensure that its must-take contract quantities are priced at retail rates for the purpose of booking revenues into its account, rather than at the much lower rates associated with sales of surplus power. [55] As a result, DWR's total revenues will be higher than under the protocol established in the proposed decision, and less subject to fluctuations due load and resource imbalances.

SCE, on the other hand, argues that the pro rata approach could increase surplus sales of utility resources (and less of DWR contract quantities), relative to the status quo. This, in turn, would have the effect of reducing utility sales revenues. To address these concerns, SCE reiterates its proposal for a sales revenue accounting protocol that would place all existing utility resources (must-take or dispatchable) first in line to be priced at retail rates for the purpose of

[55] This differential is substantial: In its comments, DWR uses an estimate of $95/MWh for retail sales and $20/MWh for sales of surplus. See DWR Comments, September 6, 2002, Attachment 2.

calculating utility revenues. SDG&E also reiterates its proposal for a similar hierarchy when must-take quantities exceed loads.[56] PG&E proposes an accounting protocol that would treat DWR contract power (must-take and dispatchable) as the first to sell at surplus or to curtail, relative to utility must-take resources.[57]

We understand the motivation behind each of these proposals—clearly DWR prefers a protocol that results in more of its contract quantities being accounted for as retail sales (and less as surplus sales), and the utilities prefer the opposite.[58] However, as described above, the utilities will not be making the distinctions that DWR, SDG&E or SCE recommend in dispatching their integrated resource portfolios.

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:[59] (1) calculating the

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[56] See Opening Comments of SCE on the Proposed Decision , pp. 9-11; Opening Comments of SDG&E on Proposed Decision, pp. 7-8.

[57] Opening Comments of PG&E on Proposed Decision, p. 11.

[58] The total procurement costs to ratepayers is the same either way—the only difference is to which "pot" of revenue requirements (utility versus DWR) the costs are assigned.

[59] As can be seen from the calculations presented in Attachment 2 of DWR's comments, there is no need to specify a dispatch order among must-take resources or between utility resources and DWR contracts for the purpose of calculating revenue streams under our adopted protocol. This is because revenues from retail customers are calculated as a "residual" after the revenue from sale of surplus is prorated and allocated. It is only under DWR's preferred approach to accounting for surplus sales revenues—i.e., determining retail revenues first, and treating surplus sales as the residual calculation, that the order in which resources are dispatch to meet loads (or curtailed) even becomes an issue for revenue accounting purposes.

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.

In their comments on the proposed decision, SDG&E and SCE urge the Commission to specify that the revenues from sales of excess energy will be apportioned to each utility or its customers individually, and not to the utilities as a pool. SCE recommends that this be accomplished through the development and operation of utility-specific balancing accounts that would capture each utility's allocation of DWR costs and each utility's wholesale and retail revenues paid to DWR. We believe that this issue belongs in DWR's 2003 revenue requirements proceeding, to be considered in the context of DWR cost allocation alternatives, and do not address it here.

8. Operational and Administrative Functions

Under the operational allocation approach adopted today, the utilities will now perform all of the day-to-day scheduling and dispatch functions for the DWR contracts allocated to their portfolios, just as they will perform these functions for their existing resources and new procurements. These functions include: day-ahead, hour-ahead and real time trading, scheduling transactions with all involved parties (e.g., suppliers, the ISO and transmission providers), making surplus sales, preparing forecasts and obtaining relevant information for these functions, such as transmission availability, among others.

Legal title to the contracts resides with DWR. Financial reporting responsibilities, including those associated with the DWR revenue requirements proceeding and Trust indenture reporting requirements, will also remain with DWR. In addition, DWR will be financially responsible for paying all contract-related bills. However, as DWR points out, this does not require that DWR staff and consultants continue to perform the billing and collecting "settlement" function for those contracts. Rather, we expect the utilities to assume these activities for the DWR contracts as they resume the same settlement functions for new procurements. In other words, the utility would verify the invoices and instruct DWR to pay the bills.[60] The utilities should work with DWR to establish the frequency and format of any information that will ensure fulfillment of these remaining responsibilities, and provide this information to DWR on a timely basis. The resulting arrangements should be reflected in the operating agreements between the utilities and DWR, discussed further below.

As financial obligor under the allocated contracts, DWR will also need to monitor performance of the generators under the contracts to enable DWR as the contract counter party to make decisions related to actions to be taken in the event of performance issues with generators, contract disputes, defaults, or to defend DWR in the event of counterparty claims against DWR. In undertaking

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[60] See RT at 154-155. We recognize that DWR will require sufficient information to verify and validate that payments and remittances are appropriate. This might include reviewing and auditing the remittances and payments periodically, which will have an impact on DWR's revenue requirements.

these actions, DWR should work in concert with the utilities through provisions to be incorporated into the operating agreements.

We turn next to the issues surrounding utilities assuming responsibilities currently borne by DWR under the gas tolling provisions of the DWR contracts. Currently, a number of the combustion turbine DWR contracts contain gas tolling provisions under which DWR can accept the gas price from the seller or "bring" (e.g., purchase) the gas supplies itself. As DWR explains:

> "Usually on an annual basis a fuel plan is submitted. We sit down with the counterparties…. Essentially, they are out there buying the gas at various points on the pipelines and putting a little markup on it. If we can do it cheaper and better, we will do it."[61]

At the outset we should distinguish between *administrative* responsibilities (e.g., choosing to buy gas, contacting gas suppliers, entering agreements to buy gas) and *financial* responsibilities (i.e., responsibility for paying from a utility revenue requirement for gas procured to generate electricity under DWR contracts). PG&E appears to argue that the Commission cannot impose *either* administrative or financial responsibility under the gas tolling provisions to the

[61] RT, p. 147.

utilities.[62] SDG&E and SCE apparently object only to imposition of financial responsibility.[63]

Gas tolling provisions are not unusual in contracts that involve combustion turbine technologies. From an operational standpoint, they provide the contract administrator with an opportunity to minimize an important component of variable costs (i.e., fuel) under these contracts through the regular review of fuel plans and consideration of alternate gas supply options. The utility, and not DWR, should now assume this function because it goes hand in hand with the objective of economic dispatch (to minimize operating costs) for which the utility is now clearly responsible. Moreover, to have DWR continue in this role ignores the fact that it is exiting the electric procurement business in all other respects.

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[62] See Opening Comments of PG&E on Proposed Decision, p. 4: "The [proposed decision] erroneously specifies that the utilities shall become responsible for fuel planning under DWR contracts." See also Reply Comments of PG&E on Proposed Decision, p. 5. "DWR's comments seek clarity as to the party responsible for fuel procurement and the related treatment in that party's revenue requirement. That party must be DWR. PG&E is not and cannot be made legally or financially accountable for fuel, transportation, storage, hedging, or other fuel related activities under DWR contracts."

[63] See: Opening Comments of SCEon Proposed Decision, p. 3. See also Reply Comments of SCE on Proposed Decision, p. 1: "the [proposed decision] should be revised to make clear that (1) the [utilities] are not financially responsible for fuel supply that supports the operation of DWR's gas tolling contracts allocated to that [utility's] customers; and (2) the utilities' responsibility is limited to merely administering the fuel-related component of the DWR tolling contracts." See also SDG&E's July 30, 2002 Comments, p. 14 and Reply Comments of SDG&E on Proposed Decision, p. 4, objecting to: "CDWR's assertion that the utilities should assume fuel and CAISO *charge exposure* for the remainder of CDWR's contractual obligations." (Emphasis added). The concern seems to be with "charge exposure," not with administrative responsibilities, which in SDG&E's view can be addressed in an Operating Agreement.

We therefore see no merit to PG&E's position that even *administrative* responsibility under the gas tolling provisions must remain with DWR. Procurement of gas under certain contracts is part and parcel with managing the rest of a generation portfolio, and requiring that the utilities administer gas purchases is as legally permissible as requiring that the utilities administer the other aspects of the DWR contracts. Moreover, shifting responsibility for administration of gas purchases under gas tolling provisions furthers our goal of extricating DWR from day-to-day procurement activities. In sum, the utility's operational and administrative responsibilities for DWR contracts should extend to the implementation of gas tolling provisions.

The second-order question is whether the utilities can be made financially responsible for fulfilling gas-purchasing obligations under the gas tolling provisions of certain DWR contracts. As noted above, by "financially responsible" we mean responsible for paying from a utility revenue requirement for gas procured to generate electricity under DWR contracts. Making utilities financially responsible for the gas tolling provisions would require revision of both the DWR revenue requirement (reducing it to reflect a cessation of gas purchases) and the utilities' retained-generation revenue requirements (increasing them to reflect gas purchases under the tolling provisions). The utilities are not signatories to the contracts containing the gas tolling provisions, which may pose an insurmountable bar to altogether ending DWR involvement in gas procurement and making utilities financially responsible for gas purchases insofar as the contracts prohibit assignment of DWR's rights (e.g., the right to procure gas).

We observe that making the utilities financially responsible for gas purchases under the gas tolling provisions of the DWR contracts would lead to an asymmetry in cost allocation. Gas purchased by the utilities would be paid from the utilities' revenue requirements, while gas purchased by a generator would be rolled into the per-MW/h cost of electricity, and be paid from DWR's revenue requirement. We see no principled reason for in one case having gas costs become a utility obligation, while in another case having gas costs devolve upon DWR.

We note another asymmetry. The utilities are not financially responsible for any other aspect of the DWR contracts. It seems odd to single gas costs under tolling agreements out for inclusion in utility revenue requirements. Singling out gas costs for migration from DWR's Revenue Requirement to the utilities' Revenue Requirements seems inconsistent with our previously stated principle that legal title, financial reporting and responsibility for the payment of contract-related bills will remain with DWR.

A justification for making the utilities financially responsible for gas procurement may arguably be found in ABX1-1, as codified in Water Code § 80260, but this argument ultimately fails. Water Code § 80260 provides that:

> On and after January 1, 2003, the department shall not contract under this division for the purchase of electrical power. This section does not affect the authority of the department to administer contracts entered into prior to that date or the department's authority to sell electricity.

A simplistic response to an argument that Water Code § 80260 bars DWR from having any responsibility (administrative or financial) for gas procurement is that this section speaks only of "electrical power," and so this provision is not implicated by the discussion at hand. The counter is that electric energy involves more than just electrons, but no one thinks DWR should buy, say, land. To this argument the reply is that as posited here, the utilities, and not DWR, would be the ones entering the contracts, and that paying for gas, whether procured by a generator or by a utility, under the tolling provisions, is part of "administering contracts entered into prior to [January 1, 2003].” DWR would simply reimburse the utilities at the end of the day (or at whatever interval is appropriate) for their reasonable gas procurement costs.

Obviously, divorcing decision-making responsibility from financial responsibility is an invitation to disaster. This leads us directly to the question of whether and how this Commission can review utility administration of DWR contracts.

9. Reasonableness Review Risk and Indemnification

The utilities each argue that how they administer the DWR contracts[64] is between themselves and DWR,[65] and that this commission cannot interpose itself into the assertedly exclusive DWR/utility relationship. But, that argument notwithstanding, SCE at least does accept that the Commission has some

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[64] In its comments on the proposed decision, Aglet Consumer Alliance (“Aglet”) has sought clarification that the reasonableness review at issue today does not reach the “the reasonableness of DWR contract terms, quantities and prices.” (Aglet Comments, p. 2. We confirm that the reasonableness of DWR contract terms, quantities and prices are not subject to reasonableness review by this Commission, but regard this as sufficiently apparent from the draft of the decision as to make the modifications that Aglet requests unnecessary.

[65]Opening Comments of PG&E on Proposed Decision, p. 3: “the [proposed decision] must be modified to state that DWR, not the Commission, is responsible under AB1X for ensuring that the DWR contracts are administered reasonably by the utilities consistent with the direction and guidance DWR provides and that the Commission lacks authority to conduct a prudence review of the utilities’ performance of these duties on behalf of DWR.”

Reply Comments of SCE on Proposed Decision: “the [proposed decision]’s reasonableness review requirement exceeds the Commission’s jurisdiction because AB1X-1 makes DWR solely responsible for management and administration of the contracts at issue.”

Jurisdiction to review how the utilities administer DWR contracts. As SCE summarizes its (and the other parties') arguments on this point:

> "AB1X-1 makes DWR solely responsible for administration of the long term contracts. No party argues that the Commission has no authority to review the [utilities'] actions in connection with their administration of the DWR contracts. Instead, the parties object to the undefined, unbounded nature of the reasonableness review language. As currently written, the [proposed decision] arguably imposes significant disallowance risk on the [utilities] for administration actions that may be sanctioned or ordered by DWR."[66]

Thus SCE at least seems to accept as a threshold matter that the Commission possesses *some* authority to review the justness and reasonableness of utility administration of DWR contracts.

SDG&E stakes out a different middle ground. SDG&E initially argues that: "this [reasonableness review] requirement is unlawful and overbroad under AB X1-1 and AB 57 (once it is signed by the Governor)."[67] But SDG&E then goes on to propose a framework for this Commission evaluating at least some aspects of SDG&E's contract administration practices.[68]

PG&E takes a more extreme position:

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[66] Reply Comments of SCE on Proposed Decision, p. 4 (emphasis added).

[67] Reply Comments of SDG&E on Proposed Decision, p. 2.

[68] Opening Comments of SDG&E on Proposed Decision, p. 5: "For example, the Commission could audit the utilities' administration of the contracts according to either a pre-determined or random schedule. The Commission could also require periodic reports from the utilities regarding the administration of the contracts." The former approach sounds very close to traditional reasonableness review. SDG&E also proposes that the Commission rely on the proposed "Operational Functional Agreement" to delineate reasonable behavior "up front." Id. Finally, SDG&E proposes informal meetings amongst its representatives, DWR representatives, and CPUC staff.

> "the [proposed decision] must be modified to eliminate the provisions purporting to vest the Commission with reasonableness review authority over costs that the utilities incur as agents of DWR or that DWR incurs directly as a result of utility operation of DWR's contracts. . . [t]he only remedy for the [proposed decision's] failure to reflect correctly this legal requirement of AB1X is to amend the [proposed decision] to remove Commission reasonableness review of the utilities' DWR contract administration." [69]

All three utilities' arguments flow from the premise that administration of the DWR contracts impacts the DWR revenue requirement, and that this Commission has no authority to engage in reasonableness review of the DWR revenue requirement.[70] Cast slightly differently, the argument runs that this commission could not review the reasonableness of DWR's, or DWR's agents', administration of the DWR contracts, and so cannot review the utilities' administration of the DWR contracts either.[71]

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[69] Reply Comments of PG&E on Proposed Decision, p.3. See also Opening Comments of PG&E on Proposed Decision, p. 3, quoted above.

[70] See Opening Comments of PG&E on Proposed Decision, p. 9: "under no circumstances would DWR contract costs in DWR's revenue requirement be subject to the Commission's reasonableness review under AB1X, whether the contracts are managed by DWR or the utilities." See also SDG&E Opening Comments, pp. 4-5.

[71] See Opening Comments of SCE on Proposed Decision, p.2, n.1. See also Opening Comments of SDG&E on Proposed Decision, p. 2: "there is no legitimate basis to impose reasonableness review burdens on the utilities based on their administration of the contracts when CDWR was itself immune from such risk pursuant to Assembly Bill (AB) X1-1." For a further gloss on the argument, see Opening Comments of PG&E on Proposed Decision, p. 7: "If DWR should choose instead to have another agent or agents manage its contracts, those costs and the decisions of those agents would not be subject to review by this Commission."

The premise underlying this argument is one with which we do not agree. The utilities' arguments rest on Water Code Section 80110, which provides in pertinent part that: "any just and reasonable review under [Public Utilities Code] Section 451shall be conducted and determined by the department."[72] The utilities' arguments do not account for the language in AB57, Section 1, (d) that confers responsibility upon this Commission to "assure that each electrical corporation optimizes the value of its overall supply portfolio, including Department of Water Resources contracts and procurement pursuant to Section 454.5 of the Public Utilities Code."[73] Section 454.5 of the PU Code, as enacted in AB57, provides in pertinent part in subsection (d)(2) that, notwithstanding language eliminating "the need for after-the-fact reasonableness reviews of an electrical corporation's actions in compliance with an approved procurement plan," the Commission "may establish a regulatory process to verify and assure that each contract was administered in accordance with the terms of the contract . . ."

SDG&E conclusorily asserts that the reasonableness review envisioned by the [proposed decision] "goes beyond the process envisioned by this provision," but does not explain how. The utilities would presumably read the word "contract" in subsection (d)(2) as referring only to a contracts to which a utility is a party, and the costs of which are included in a utility's revenue requirement.[74]

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[72] Water Code Section 80110.

[73] Public Utilities Code Section 454.5.

[74] Such an argument is apparent in PG&E's assertion that: "the scope of prudence review and 'disallowance risk' that the Commission is empowered to exercise is explicitly limited to actions undertaken by the utilities in dispatch and operation of their own resources as those actions affect their own costs and services," even though PG&E

Footnote continued on next page

This reading is impossible to square with the language in AB57, Section 1, (d), linking 454.5 to the Commission's legislative mandate to optimize "overall supply portfolio[s], including Department of Water Resources contracts."

The broader reading of "contract," however, appears to implicate AB1X and puts at issue the scope of this Commission's say over recovery of the elements of DWR's Revenue Requirement. The Commission cannot determine that some portion of DWR's Revenue Requirement is *not* just and reasonable and must be borne by shareholders, without running afoul of Water Code Section 80110. In fulfilling our legislative mandate to review the reasonableness of the utilities' administration of the DWR contracts (including the gas tolling provisions thereof), we are constrained by the fact that this Commission cannot deny DWR recovery of its reasonable costs.[75] Were ensuring that DWR recovers its revenue requirement the *only* constraint on our reasonableness review, there would be no difficulty in this Commission simply allocating the DWR Revenue Requirement between customers – who would pay only just and reasonable costs – and utility shareholders – who would bear unjust and unreasonable costs.

The utilities argument, as elaborated earlier, rests on a misreading of Water Code Section 80110. Water Code Section 80110 vests DWR with responsibility for "any just and reasonable review *under Section 451* . . ." The review of the contracts, as we have explained above, will be "*pursuant to Section 454.5 . . .*"[76] <u>and not pursuant to Section 451. Water Code Section 80110 is quite</u>

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does not cite to AB57 by name. Opening Comments of PG&E on Proposed Decision, p. 3.

[75] See D.02-02-051 ("Rate Agreement Decision"), rehearing denied in D.02-03-063.

[76] AB57, Section 1(d).

narrow in its delegation. Unsurprisingly, it makes no mention whatsoever of Public Utilities Code Section 454.5, a law that is both more recent than AB1X (which codified Water Code Section 80110), and a law that is more specific than AB1X insofar as it directly addresses this Commission's review of utility contract administration. AB1 X1 addresses DWR's role with respect to its revenue requirement but does not limit the Commission's ability to regulate utilities.

We note parenthetically that the review described here would not impact DWR's revenue requirement. DWR will continue to review its revenue requirement per Water Code Section 80110 and Public Utilities section 451, and will continue to submit its revenue requirement to this Commission and recover that revenue requirement per the Rate Agreement Decision. The Public Utilities Code Section 454.5 process established by this Decision will be devoted to allocating costs between ratepayers and shareholders, without impacting DWR revenues.

Once the threshold *legal* issue of *whether* the CPUC may review the reasonableness of utility administration of DWR contracts is disposed of, the question becomes one of policy: *should* the Commission exercise its jurisdiction over contract administration? SCE argues "no," lest "the [utilities] have two masters with potentially quite different agendas," which results in "significant disallowance risk on the [utilities] for administration actions that may be sanctioned or ordered by DWR."[77] DWR, in its comments, identifies two scenarios that "could exist where the utility would not be allowed to recover such costs under the Commission's determination but DWR may or could

[77] Reply Comments of SCE on Proposed Decision, p. 4.

include such costs in its own revenue requirement."[78] SDG&E makes an argument (albeit in the context of arguing that *no* reasonableness review is appropriate) that: "there is no need or legitimate basis to impose hindsight reasonableness review burdens on the utilities. There are simply too many variables and moving parts to justify this approach, particularly when the utilities did not negotiate or structure these contracts, nor do they retain ultimate financial and legal responsibility for them."[79] SDG&E proffers alternative approaches, as note above, to ensuring that they administer DWR contracts in a just and reasonable fashion.

We do not find these arguments compelling. We are hard pressed to imagine a scenario in which DWR orders a utility to take some action, only to have this Commission find that the utility acted unreasonably. The need for some review is clear, given that the utilities will be playing with other peoples' money, and, as noted earlier, divorcing decision-making from financial responsibility is an invitation to disaster. Finally, as already noted, this Commission has a legislative mandate under AB57 to ensure that the utilities' contract management costs are just and reasonable.

SCE raises a due-process argument. SCE states in its Opening Comments that: ·"parties were not afforded an opportunity to address the legality of Commission review of administration of the DWR contracts," and in its Reply Comments that "parties were not afforded an opportunity to comment on the legality and appropriateness of the reasonableness review requirement before the [proposed decision] was issued. For this reason, the reasonableness review

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[78] Opening Comments of DWR on Proposed Decision, p. 7.

[79] Reply Comments of SDG&E on Proposed Decision, p. 2.

requirement should be removed from the [proposed decision].” A party that has been able to brief a *legal* issue twice prior to issuance of a decision has had its opportunity to be heard, and these arguments are not meritorious. SCE has long been on notice that reasonableness review was an issue in the broader Procurement OIR, and can hardly be surprised to see the issue rear its head in miniature in this phase of the proceeding. SCE itself introduced the issue of reasonableness review into the proceeding at the PHC, as noted in the Scoping Memorandum: “At the PHC, PG&E, Edison, the Independent Energy Producers Association, and Dynegy Marketing and Trade ask that the Commission consider adopting here policy framework statements on timely recovery of costs and limiting the risk associated with after-the-fact reasonableness review . . . Parties may propose specific language that addresses this concern in their testimony.” SCE may fairly claim that we did not see things their way, but SCE should not be heard today to complain of being ambushed.

Moreover, we do not decide today the *level* of review that we will apply to a review of utility contract administration. It is sufficient for the moment to conclude that this Commission will review utility contract administration practices for their reasonableness, while deferring our enunciation of the applicable standard of review to some time prior to January 1, 2003.

Ironically, SCE contends that this – our failure to go far enough down a road SCE first says we ought not tread at all – is itself legal error. The only legal argument proffered by SCE is that “to allow unlimited financial exposure is tantamount to assigning financial responsibility for the contracts to the utilities in violation of AB 1X-1’s requirements that DWR remain liable for the financial impacts of the contracts."[80] We reject both the equation of "unlimited financial exposure" with "financial responsibility for the contracts" and the assertion that ABX1-1 requires that "DWR remain liable for the financial impacts of the contracts." The former is simply hyperbole, while the latter is unsupported by anything more than a generic citation to the testimony of a DWR witness, whose interpretation of the law (even if as SCE claims) is not binding on this Commission. SCE cites to no portion of ABX1-1 that requires DWR to remain liable for "financial impacts of the contracts," and we are aware of none.

Finally, the utilities contend that DWR will need to indemnify them for any claims that might arise out of the administration of the contracts. For example, if a supplier does not perform as required under a DWR contract, SDG&E argues that the utility should not be liable for that supplier's failure to perform.[81] There may be certain types of "failure to perform" claims for which DWR indemnification is appropriate, as the utilities suggest. These circumstances should be considered in the development of the operating agreements discussed above. However, DWR indemnification should not relieve the utilities from the responsibility of implementing the terms of the contract in good faith, so that the supplier has a reasonable opportunity to perform under those terms.

10. Implementation Filings

As discussed in this decision, the Servicing Arrangements between DWR and the utilities will need to be altered to reflect the new operational arrangements we adopt today. DWR should negotiate with SCE and SDG&E

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[80] Opening Comments of SCE on Proposed Decision, p. 3.

[81] July 30, 2002 Comments of SDG&E, p. 13.

appropriate modifications to their respective Servicing Agreements and DWR should request of us appropriate modifications to the Servicing Order governing PG&E. The modifications should be submitted in Application (A.) 01-06-044, A.01-06-039 and A.00-11-038 et al. by October 1, 2002.

The parties indicate in their comments on the proposed decision that separate operational agreements between DWR and the utilities will also be needed to address operating functions associated with contract allocation that are beyond the current scope of the Servicing Arrangements. The utilities and DWR have been working informally on developing these implementation arrangements. Accordingly, they should jointly file a proposal for operational agreements in this proceeding no later than October 1, 2002.

As discussed in Section 9 above, we will address the applicable standards of reasonableness for the utility administration of DWR contracts by subsequent Commission decision. The joint filing on operating agreements should include a separate proposal for these standards for our consideration. If there remain specific issues with respect to either the operating agreements or standard of review where agreement cannot be reached by the filing date, the utilities and DWR should highlight those differences in a companion comparison exhibit.

Today's decision concerning the operating responsibilities of the utilities with respect to DWR contracts, and which functions we expect to remain with DWR, will have an impact on the division of costs and associated revenue requirements between them. DWR's revenue requirement should decrease as it relinquishes its administration of the contracts and that, conversely, the utilities will incur costs concurrent with assuming the administrative functions associated with these contracts. However, we do not believe that operating or servicing agreements between DWR and the utilities represent the appropriate forum for addressing the details of the amount and recovery of the administrative costs to the utilities, as SDG&E suggests.[82] Rather, these issues should be addressed in each utility's general rate case, where we also consider the administrative costs associated with non-DWR procurement contracts. In this way, we can review the administrative costs related to the DWR contracts in the context of total administrative cost levels to determine the need for any base rates increases.

As discussed in Section 7, the utilities should work with DWR to develop specific accounting and reporting procedures consistent with the pro rata approach to accounting for surplus sales revenues that we adopt today. This information should be submitted in the 2003 Revenue Requirements proceeding within 10 days of the effective date of this decision.

Finally, we direct each utility to file updated tables reflecting revised estimates of its residual net short position based on the allocation of DWR contracts we adopt today. This compliance filing should be filed in this proceeding within 10 days from the effective date of this decision.

The electronic service protocols established in this proceeding by Assigned Commissioner's Ruling Establishing Category and Providing Scoping Memo, dated April 2, 2002, shall be used for all filings required by this decision.

11. Comments on Proposed Decision

The proposed decision of ALJ Gottstein in this matter was mailed to the parties in accordance with Public Utilities Code §311(d) and Rule 77.1 of the Rules of Practice and Procedure. As set forth in §311(d), the 30-day waiting period for proposed decisions may be shortened upon the stipulation of all parties to the proceeding. By assigned ALJ ruling dated September 9, 2002,

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[82] SDG&E's Opening Comments, pp. 10-11.

parties were asked to address if they would stipulate to shortening the waiting period by one day. We received no opposition; therefore we shorten the waiting period by one day. In addition, pursuant to Rule 87, we shortened the comment period on the proposed decision.

Comments were filed on September 6, 2002 by the utilities, DWR, ORA and Aglet Consumer Alliance. The utilities and DWR filed reply comments on September 12, 2002.

As described in this decision, we clarify our expectations with respect to the utility and DWR filings that will follow, describe where the utilities' recovery of DWR-contract related administrative costs will be considered by the Commission, expand our discussion of gas tolling and reasonableness review issues and make other corrections and clarifications in response to the comments.

Findings of Fact

1. Currently, DWR retains title to the energy from its contracts notwithstanding the fact that energy is traded to and distributed by the utilities under the Servicing Arrangements.

2. The language of AB57 makes it clear that the Legislature contemplated that DWR contract energy would be allocated to the utilities as implied by the April 2 Scoping Memo.

3. Under the operational approach, the utilities are responsible for integrating the scheduling and dispatch of the specific DWR contracts allocated to them with their existing generation assets, contracts and new procurements.

4. The operational approach best reflects the reality that, as of January 1, 2003, DWR is no longer in the business of procuring electric power on behalf of SCE, SDG&E and PG&E's customers, and the utilities resume that responsibility.

5. Retaining a separate DWR resource portfolio, as proposed under the "planning approach," perpetuates a two-tiered procurement system in California

that was put in place on a temporary basis, and only under emergency circumstances.

6. Adopting a planning approach for 2003, as a transition to operational contract allocation, would effectively limit the utilities' procurement authority to a one year period. This, in turn, could limit both suppliers' interest in utility solicitations and the utilities' ability to acquire the necessary resources at more favorable prices.

7. The PG&E and joint SCE/SDG&E proposals for contract allocation under the operational allocation approach are identical except for their allocation of the Coral and Sunrise contracts.

8. As discussed in this decision, resolving the contract allocation issues in this proceeding does not require us to select among the competing allocation principles and comparison metrics, to the exclusion of all others.

9. The various allocation principles and associated comparison metrics presented in this proceeding have disadvantages when considered in isolation.

10. The utility proposals appear to have been driven by results, and not by the underlying allocation principles they propose and argue for in their filings: Irrespective of the comparison metric used (energy or capacity allocated, residual net short, any of the cost metrics), the utility consistently comes out ahead with the application of its preferred allocation methodology.

11. The ALJ alternate contract allocation that allocates the Sunrise contract to SDG&E and the Coral contract to PG&E strikes a reasonable balance between the competing proposals of PG&E and SCE/SDG&E and the various principles and comparison metrics considered.

12. The ALJ alternate contract allocation spreads the delivery risk associated with the Sempra, Coral and Sunrise contracts more equitably among all three utilities when compared to the utilities' proposals.

13. The ALJ alternate contract allocation reaches a reasonable outcome in terms of SP-15 and NP-15 zonal allocations by assigning to the southern utilities all contract quantities that designate a SP-15 delivery point, and all to PG&E all contract quantities that designate a NP-15 delivery point.

14. PG&E's preferred allocation and the permutation of the Coral split that PG&E presented in its July 30 comments would allocate a significant portion of the Coral contract quantities designated for NP-15 to the south.

15. The ALJ alternate contract allocation produces a resolution of the contract allocation issues without requiring any utility to manage the contract of its affiliate.

16. Adopting an advance trigger mechanism for contract reallocation, as proposed by the utilities, would insert an unacceptable level of additional uncertainty and complexity into the procurement process going forward.

17. SCE's position that total costs must follow contract allocation is based on the premise that the utility operator must see the total cost of each resource in making economic dispatch decisions.

18. To achieve economic dispatch, the operating utility needs only to see and compare the variable costs of each DWR contract with the other resources in its portfolio.

19. Allocating variable contract costs to each utility based on today's contract allocation is required for economic dispatch.

20. Under the operational allocation approach adopted today, Decisions regarding the sale of surplus power from DWR contracts will be made by the utility on a portfolio basis, as follows: For all the resources in its portfolio (including the allocated DWR contracts), the utility will dispatch all of the must-take quantities plus all of the dispatch quantities up to the market price for each product. The utility then determines whether it needs to purchase additional

quantities to meet its residual net short or, if it finds itself in a long position, whether it makes more sense to sell excess power from its portfolio, ramp down utility-owned generation plants, or take some combination of these and other actions based on least-cost economic dispatch principles.

21. DWR's proposed dispatch priority for DWR must-take contracts could work at cross purposes with economic dispatch because it may make more sense to supply incremental power from lower-cost utility generating assets to customers, even if this means that DWR power (as a component of the utility's portfolio) is sold on the market at a "loss."

22. DWR's concerns over ending up with a higher computed average rate should not drive the utility's dispatch decisions.

23. As discussed in this decision, the utilities should not impose a dispatch or curtailment hierarchy among resources based on the timing of their acquisition, or make other artificial distinctions between DWR contracts and other resources within their integrated resource portfolio.

24. Under the operational approach to contract allocation, we need to establish an accounting protocol to credit revenues resulting from sales of excess power to the corresponding (DWR or utility) revenue requirement.

25. The surplus sales accounting protocol that SCE and SDG&E propose would impose an artificial hierarchy to dispatched quantities, based on the timing of resource acquisition, that does not represent the way surplus sales will be generated in an integrated utility portfolio. Similarly, SDG&E's proposed sequential protocol for dispatch and curtailment among must-take contracts is inconsistent with the manner in which resource portfolio decisions will be executed.

26. DWR's proposal for accounting for surplus sales ensures that its must-take contract quantities are priced at retail sales for the purpose of booking revenues

into its account, rather than at the much lower rates associated with sales of surplus sales. The utilities' proposals tend to result in the opposite, i.e., place DWR contract quantities more on the margin so that utility sales revenues (at retail rates) are higher than under DWR's proposed protocol or the pro rata approach.

27. Sales revenues should be accounted for based on the composite of resources that the utility dispatches from its portfolio, rather than the timing with which the utilities procured specific resources.

28. As discussed in this decision, sequencing protocols for dispatch or curtailment of must-take resources, such as the ones that SDG&E proposes, are not necessary or appropriate in a procurement environment where the utility dispatches all must-take resources from an integrated utility portfolio. They are also not required to implement the pro rata approach to accounting for surplus sales (or the corollary, retail revenues) adopted in this decision.

29. Retaining legal title of the DWR contracts requires that DWR continue to perform financial reporting responsibilities (e.g., for the DWR revenue requirements proceeding and Trust indenture reporting), and be financially responsible for paying all contract-related bills.

30. As described in this decision, the utilities should perform all of the day-to-day scheduling and dispatch functions for the DWR contracts allocated to their portfolios, just as they will perform these functions for their existing resources and new procurements. This includes performing the billing and collecting "settlement" functions for DWR contracts, and verifying all invoices.

31. Gas tolling provisions are not unusual in contracts that involve combustion turbine technologies. From an operational standpoint, they provide the contract administrator with an opportunity to minimize an important

component of variable costs (i.e., fuel) under the contract through regular review of fuel plans and consideration of alternate gas supply options.

32. To have DWR continue in the role of administering the gas tolling provisions of the contracts ignores the fact that it is (1) exiting the electric procurement business in all other respects and (2) not accountable to utility ratepayers for the gas tolling decisions it might make in the future.

33. It makes operational sense to have the utility to conduct the fuel plan review and consider alternate gas supply options for those contracts with tolling arrangements, since this function goes hand in hand with the objective of economic dispatch (to minimize operating costs) for which the utility is now clearly responsible. Making utilities financially responsible for fulfilling gas-purchasing obligations would lead to asymmetry in cost allocation, as discussed in this decision. It would also single out gas costs under tolling agreements for inclusion in utility revenue requirements, when the utilities are not financially responsible for any other aspect of the DWR contracts.

34. Divorcing utility decision-making responsibility from financial responsibility is an invitation to disaster without some form of Commission reasonableness review.

35. The utilities' arguments that the Commission has no authority to engage in reasonableness review of DWR contract administration do not account for the language in AB 57, Section 1, (d) that confers responsibility upon this Commission "to assure that each electrical corporation optimizes the value of its overall supply portfolio, including Department of Water Resources contracts and procurement to Section 454.5 of the Public Utilities Code," and that under subsection (d)(2) of Section 454.5 the Commission may "establish a regulatory process to verify and assure that each contract was administered in accordance with the terms of the contract."

36. Today's decision concerning the operating responsibilities of the utilities with respect to DWR contracts, and which functions we expect to remain with DWR, will have an impact on the division of costs and associated revenue requirements between them. DWR's revenue requirement should decrease as it relinquishes its administration of the contracts and, conversely, the utilities will incur costs commensurate with assuming the administrative functions associated with these contracts.

37. Having the utilities account for the administrative costs associated with DWR contracts in the same manner as the administration costs associated with other procurement contracts (i.e., in each utility's general rate case), will enable the Commission to review them in the context of overall administrative cost levels to determine the need for any rate increases to base rates.

38. The utilities should be expected to manage the DWR contracts in a reasonable manner, subject to Commission review and oversight.

39. Parties have stipulated to a one-day shortening of the 30-day statutory waiting period before the Commission takes action, pursuant to Pub. Util. Code Sec. 311(d).

Conclusions of Law

1. The requirement of ABX1-1 that DWR retain title to DWR contract energy does not serve as a bar to allocation of operational control over DWR contract energy.

2. Current practices under the Servicing Arrangements are nowhere legally mandated, except under those agreements, and are subject to modification at our discretion.

3. An operational allocation of DWR contracts to the utilities is reasonable, consistent with the law, and should be adopted.

4. The ALJ alternate contract allocation, as presented in Table 1, is reasonable and should be adopted.

5. Economic dispatch should be the operating rule for the utility's portfolio of resources, including the DWR contracts we allocate today.

6. A reasonable policy approach is that the allocation of the variable costs of DWR contracts should follow our adopted contract allocation. We will implement this approach in the DWR 2003 revenue requirements proceeding.

7. As discussed in this decision, it is reasonable to prorate revenues from the sale of surplus power between DWR contracts and other resources in the utility's portfolio based on the relative quantities dispatched from those sources.

8. Effective January 1, 2003, it is reasonable that the utilities fully assume the operational and administrative functions for DWR contracts described in today's decision.

9. Requiring that the utilities administer the gas purchases for contracts with gas tolling provisions is as legally permissible as requiring that the utilities administer the other aspect s of the DWR contracts. As discussed in this decision, DWR should reimburse the utilities for their reasonable gas procurement costs.

10. The Commission should review utility DWR contract administration practices for their reasonableness, including dispatch decisions related to these contracts, and enunciate the applicable standard of review in a subsequent decision. The forum for this review should be the annual procurement proceedings, where the utility procurement process as a whole is reviewed.

11. The Servicing Arrangements between DWR and the utilities should be modified to reflect the new operational arrangements under contract allocation. In addition, as discussed in this decision, separate operational agreements between the utilities and DWR should be developed to address the operational

functions that go beyond the responsibilities addressed in the existing Servicing Arrangements. The utilities should work with DWR to establish the frequency and format of any information necessary to fulfill DWR's remaining responsibilities, as described in this decision, and provide that information to DWR on a timely basis.

12. Recovery of the utilities' administrative costs associated with DWR contract allocation should be addressed in each utility's general rate case, where we also consider the administrative costs associated with non-DWR contracts.

13. In order to allow the Commission to take action on a timely basis, it is reasonable to shorten the waiting period by one day, pursuant to §311(d) and Rule 87.

14. In order to move forward with procurement planning as expeditiously as possible, this order should be effective today.

INTERIM ORDER

IT IS ORDERED that:

1. The Department of Water Resources (DWR) contracts are allocated to the resource portfolios of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E), collectively "the utilities," as shown in Table 1.

2. Effective January 1, 2003, the utilities shall fully assume all the operational, dispatch and administrative functions described in this decision for the DWR contracts allocated pursuant to Ordering Paragraph 1. Between now and January 1, 2003, the utilities shall work with DWR to facilitate a smooth transition. The reasonableness of the utilities' administration of the DWR contracts we allocate today, including how they elect to dispatch the contract

power quantities relative to other resources in their portfolio, shall be at issue over the life of the contracts. The forum for the Commission's review of the reasonableness of DWR contract administration shall be the annual procurement proceeding, where the utility procurement process as a whole is reviewed. The Commission shall enunciate the standards of review in a subsequent decision.

3. As discussed in this decision, the Servicing Arrangements between DWR and the utilities shall be altered to reflect the new operational arrangements under contract allocation that we adopt today. DWR shall negotiate with SCE and SDG&E appropriate modifications to their respective Servicing Agreements and DWR shall request of us appropriate modifications to the Servicing Order governing PG&E. DWR shall submit its proposed modifications in Application (A.) 01-06-044, A.01-06-039 and A.00-11-038 et al. by October 1, 2002. Comments are due by October 11, 2002 and replies are due by October 16, 2002. The Assigned Commissioners and Administrative Law Judges in this proceeding and the above-referenced proceedings on utility Servicing Arrangements will coordinate closely to ensure that the modifications are consistent with today's order.

4. As discussed in this decision, the utilities and DWR shall jointly file proposed operational agreements and proposed standards for our reasonableness review no later than October 1, 2002 in this proceeding. If there remain specific issues where agreement cannot be reached by the filing date, the utilities and DWR shall highlight those differences in a companion comparison exhibit. Comments are due by October 11, 2002 and replies are due by October 16, 2002.

5. Economic dispatch shall be the operating rule for the utility's portfolio of resources, including the DWR contracts we allocate today. The utilities shall not implement protocols that impose a dispatch or curtailment hierarchy among

resources based on the timing of their acquisition, or make other artificial distinctions between DWR contracts and other resources in their resource portfolio.

6. The allocation of the variable costs of DWR contracts shall follow today's adopted contract allocation. In developing its revenue requirements proposal, DWR shall present a contract-by-contract delineation between fixed (or sunk) and variable costs for our consideration in the 2003 DWR revenue requirements proceeding.

7. As discussed in this decision, revenues from the sale of surplus power shall be prorated between DWR contracts and other resources in the utility's portfolio based on the relative quantities dispatched from those sources. This involves the following steps: (1) calculating the amount of surplus sales based on the excess of total utility portfolio resources (including the 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). The utilities shall work with DWR to develop specific accounting and reporting procedures consistent with this policy, and shall submit these procedures in DWR's 2003 revenue requirements proceeding within 10 days from the effective date of this decision.

8. Each utility shall file updated tables reflecting revised estimates of its residual net short position based on the allocation of DWR contracts we adopt today. The residual net short positions shall be presented separately on an energy and capacity basis for each month in 2003 under low, reference and high case scenarios. As part of these filings, the utilities shall include hourly residual net short duration curves for the low, reference and high case scenarios. In

addition, each utility shall file electronic workpapers in Excel format providing estimates of the residual net short position on an hourly basis for each of the modeled scenarios. This compliance filing shall be filed in this proceeding within 10 days from the effective date of this order.

9. The electronic service protocols established in this proceeding by Assigned Commissioner's Ruling Establishing Category and Providing Scoping Memo, dated April 2, 2002, shall be used for all filings and submittals required by this decision.

This order is effective today.

Dated September 19, 2002, at San Francisco, California.

HENRY M. DUQUE
CARL W. WOOD
GEOFFREY F. BROWN
MICHAEL R. PEEVEY
Commissioners

I will file a dissent.

/s/ LORETTA M. LYNCH
President

TABLE 1 : Adopted DWR Contract Allocation

Long-Term Contract	Contract Category	Adopted Allocation
Allegheny 2 150 MW 6x16 in NP-15 for 2003	Must-Take	PG&E
Calpine 1 Product 1	Must-Take	PG&E
Calpine 2 Product 1	Must-Take	PG&E
Capitol Power	Must-Take	PG&E
Clearwood	Must-Take	PG&E
Constellation - Product 2 400 MW 7x24 May to Oct. '03	Must-Take	PG&E
Coral	Must-Take	PG&E
El Paso 50 MW 6x16 in NP-15	Must-Take	PG&E
Intercom	Must-Take	PG&E
Santa Cruz	Must-Take	PG&E
Soledad	Must-Take	PG&E
Allegheny1 Excluding NP-15 deliveries	Must-Take	SCE
Constellation 200 MW 6x16 through Jun. '03	Must-Take	SCE
Dynegy	Must-Take	SCE
El Paso 50 MW 6x16 in SP-15	Must-Take	SCE
Morgan Stanley	Must-Take	SDG&E
PGE&T Wind	Must-Take	SCE
Primary Power	Must-Take	SDG&E
Sempra	Must-Take	SCE
Whitewater Cabazon	Must-Take	SDG&E
Whitewater Hill	Must-Take	SDG&E
Williams	Must-Take	SDG&E
Calpine 1 - Product 2	Dispatchable	PG&E
Calpine 2 - Product 3 & 4	Dispatchable	PG&E
Calpine 3	Dispatchable	PG&E
Calpine SJ	Dispatchable	PG&E
Calpeak (3 contracts) New Site, Panoche, and Vaca-Dixon	Dispatchable	PG&E
GWF	Dispatchable	PG&E
Pacificorp	Dispatchable	PG&E
Wellhead (3 contracts) Fresno, Gates, and Panoche	Dispatchable	PG&E
Alliance	Dispatchable	SCE
Calpeak (3 contracts) Border, El Cajon, and Escondido	Dispatchable	SDG&E
Dynegy 1,000 MW On-Peak System Contingent	Dispatchable	SCE
High Desert	Dispatchable	SCE
Sunrise	Dispatchable	SDG&E

ATTACHMENT 1

LIST OF ACRONYMS AND ABBREVIATIONS

ATTACHMENT 1

LIST OF ACRONYMS AND ABBREVIATIONS

AB	Assembly Bill
ALJ	Administrative Law Judge
April 2 Scoping Memo	April 2, 2002 Assigned Commissioner Ruling Establishing Category and Providing Scoping Memo
California Power Authority	California Consumer Power and Conservation Financing Authority
CERS	California Energy Resource Scheduling
DWR	Department of Water Resources
ISO	Independent System Operator
MW	megawatts
NP-15	north of Path 15
OIR	Order Instituting Rulemaking
ORA	Office of Ratepayer Advocates
p.	page
PG&E	Pacific Gas and Electric Company
PHC	prehearing conference
pp.	pages
R.	Rulemaking
RT	Reporter’s Transcript
“SC to SC”	Scheduling Coordinator to Scheduling Coordinator
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SP-15	south of Path 15
“the utilities”	PG&E, SDG&E and SCE, collectively

(END OF ATTACHMENT 1)

ATTACHMENT 2

Contract Allocation of Must-Take Contracts Under Different Options

	Must-Take Contracts	DWR Analysis Support					Utilities' Contract Allocation Proposals (July 19th Filing)			ALJ Alternate (July 26th)
		"Straw-Man" Allocation (June 11th, 2002 Letter)	**Spliting of Contract - No Affiliate Contracts** (Option 1A)	**Spliting of Contract - Allow Affiliate Contracts** (Option 1B)	**No Spliting of Contract - No Affiliate Contracts** (Option 2A)	**No Spliting of Contract - Allow Affiliate Contracts** (Option 2B)	**PG&E**	**SCE**	**SDG&E**	
NP-15 Deliveries	Allegheny 2 150 MW 6x16 in NP-15 for 2003	PG&E	PG&E	PG&E	SDGE	SCE	PG&E	PG&E	-	PG&E
	Calpine 1 Product 1	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
	Calpine 2 Product 2	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
	Capitol Power	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
	Clearwood	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
	Constellation - Product 2 400 MW 7x24 May to Oct. '03	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
	Coral 25% of Base Quantities, all Additional Quantities	PG&E	PG&E	PG&E	PG&E	PG&E	25% PG&E Remainder to SCE/SDG&E[2]	PG&E	-	PG&E[1]
	El Paso 50 MW 6x16 in NP-15	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
	Intercom	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
	Santa Cruz	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
	Soledad	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
SP-15 Deliveries	Allegheny1 Excluding NP-15 deliveries	55% - SCE 45% - SDGE	50% - SCE 50% - SDGE	70% - SCE 30% - SDGE	SDGE	SCE	SCE/SDG&E[2]	SCE	-	SCE
	Constellation 200 MW 6x16 through Jun. '03	55% - SCE 45% - SDGE	PG&E	PG&E	PG&E	PG&E	SCE/SDG&E[2]	SDG&E	SDG&E	*SCE **
	Coral 75% of Base Quantities	55% - SCE 45% - SDGE	PG&E	PG&E	PG&E	PG&E	25% PG&E Remainder to SCE/SDG&E[2]	PG&E	-	PG&E[1]
	Dynegy	55% - SCE 45% - SDGE	50% - SCE 50% - SDGE	70% - SCE 30% - SDGE	SDGE	SCE	SCE/SDG&E[2]	Firm Product- SCE Unit Contingent Product- SDG&E	Unit Contingent - SDG&E	*SCE **
	El Paso 50 MW 6x16 in SP-15	55% - SCE 45% - SDGE	PG&E	PG&E	PG&E	PG&E	SCE/SDG&E[2]	SDG&E	SDG&E	*SCE **
	Morgan Stanley	55% - SCE 45% - SDGE	50% - SCE 50% - SDGE	70% - SCE 30% - SDGE	SCE	SCE	SCE/SDG&E[2]	SDG&E	SDG&E	SDG&E
	PGE&T Wind	55% - SCE 45% - SDGE	50% - SCE 50% - SDGE	70% - SCE 30% - SDGE	SDGE	SDGE	SCE/SDG&E[2]	SCE	-	SCE
	Primary Power	55% - SCE 45% - SDGE	50% - SCE 50% - SDGE	70% - SCE 30% - SDGE	SCE	SCE	SCE/SDG&E[2]	SDG&E	SDG&E	SDG&E
	Sempra	100% - SCE	100% - SCE	70% - SCE 30% - SDGE	SCE	SDGE	SCE/SDG&E[2]	SCE	-	SCE
	Whitewater Cabazon	55% - SCE 45% - SDGE	50% - SCE 50% - SDGE	70% - SCE 30% - SDGE	SCE	SCE	SCE/SDG&E[2]	SDG&E	SDG&E	SDG&E
	Whitewater Hill	55% - SCE 45% - SDGE	50% - SCE 50% - SDGE	70% - SCE 30% - SDGE	SCE	SCE	SCE/SDG&E[2]	SDG&E	SDG&E	SDG&E
	Williams Prod B1, B2, &B3	55% - SCE 45% - SDGE	50% - SCE 50% - SDGE	70% - SCE 30% - SDGE	SCE	SCE	SCE/SDG&E[2]	SDG&E	SDG&E	SDG&E

Contract Allocation of Dispatchable Contracts Under Different Options

	Dispatchable Contracts	**DWR Analysis Support**					**Utilities' Contract Allocation Proposals** (July 19th Filing)			**ALJ Alternate** (July 26th)
		"Straw-Man" Allocation (June 11th, 2002 Letter)	**Spliting of Contract - No Affiliate Contracts** (Option 1A)	**Spliting of Contract - Allow Affiliate Contracts** (Option 1B)	**No Spliting of Contract - No Affiliate Contracts** (Option 2A)	**No Spliting of Contract - Allow Affiliate Contracts** (Option 2B)	**PG&E**	**SCE**	**SDG&E**	
NP-15 Deliveries	Calpine 1 – Product 2	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
	Calpine 2 – Product 3	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
	Calpine 3	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
	Calpine SJ	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
	Calpeak (3 units) New Site, Panoche, and Vaca-Dixon	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
	GWF	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
	Pacificorp	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
	Wellhead (3 units) Fresno, Gates, and Panoche	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	-	PG&E
SP-15 Deliveries	Alliance	SCE	SCE	SCE	SCE	SCE	SCE/SDG&E[2]	SDG&E	SDG&E	*SCE* *
	Calpeak (3 units) Border, El Cajon, and Escondido	SDGE	SDGE	SDGE	SDGE	SDGE	SCE/SDG&E[2]	SDG&E	SDG&E	SDG&E
	Dynegy 1,000 MW On-Peak System Contingent	55% - SCE 45% - SDGE	SCE	SCE	SDGE	SCE	SCE/SDG&E[2]	SDG&E	SDG&E	*SCE* *
	High Desert	SCE	SCE	SDGE	SCE	SDGE	SCE/SDG&E[2]	SCE	-	SCE
	Sunrise	SDGE	SDGE	SCE	SDGE	SCE	SCE/SDG&E[2]	PG&E	-	SDG&E[1]

1) On July 26th, ALJ Meg Gottstein requested an alternate allocation scenario reallocating the Sunrise contract to the South and Coral fully to PG&E. SCE and SDG&E were allowed to redistribute the SP-15 contracts in order to produce this additional scenario.

(*) "Italics" indicates a change from SCE/SDG&E July 19th allocation.

2) PG&E July 19th filing expressed no opinion on the allocation breakdown between SCE and SDG&E.

ATTACHMENT 3

COMPARISON OF
NET SHORT CALCULATIONS

ATTACHMENT 3

COMPARISON OF NET SHORT CALCULATIONS

- DWR's calculations represent a 7-year average of net short projections (2003-2009) from PROSYMRun35 including forecast of direct access migration.
- PG&E's calculations represent a 7-year average of net short projections (2003-2009) from PROSYMRun35 excluding forecast of direct access migration.
- SDG&E's primary calculation is based on sales projections used to allocate DWR's 2001-2002 revenue requirement, per D.02-02-052. If a forecasted net short is used, SDG&E recommends adjusting DWR's calculations to correct for resources that SDG&E claims were erroneously excluded from the PROSYMRun35.
- SCE's range is based on current data for the 2001-2002 net short for each utility: (1) the sales projections used to allocate DWR's 2001-2002 revenue requirement, per D.02-02-052; (2) DWR's June 2002 update and (3) DWR's PROSYMRun35 for the year 2003.

Net Short Calculations

Utility	DWR	PG&E	SDG&E	SCE
PG&E	41%	40%	--	46%-48%
SCE	40%	44%	--	35%-38%
SDG&E	19%	16%	16%*	14%-19%

*14% to 18% if forecasted net short is used.

ATTACHMENT 4

Assessment of Allocation of Capacity, Energy Residual Net Short and Surplus

(Summary of 7-Year Average – 2003 through 2009)

7-Year Average		DWR Support Analysis (July 26th Workshop)					Utility Proposals (July 19th Filings)		ALJ Alternate (July 26th)
		Straw Man	Option 1A	Option 1B	Option 2A	Option 2B	PG&E Proposal (July 19th)	SCE and SDG&E Proposal (July 19th)	
PG&E	**Allocated Capacity** (% of Total Contract Capacity)	39%	43%	43%	43%	43%	37%	47%	43%
	Allocated Energy (% of Total Contract Energy)	40%	42%	42%	42%	43%	38%	44%	41%
	Residual Net Short (% of IOU Load)	7%	6%	6%	6%	6%	10%	4%	7%
	Must-Take Surplus (% of IOU Load)	2%	3%	3%	3%	3%	2%	3%	3%
SCE	**Allocated Capacity** (% of Total Contract Capacity)	41%	39%	36%	37%	32%	n/a	33%	38%
	Allocated Energy (% of Total Contract Energy)	42%	40%	39%	38%	35%	n/a	39%	42%
	Residual Net Short (% of IOU Load)	7%	8%	9%	8%	11%	n/a	9%	8%
	Must-Take Surplus (% of IOU Load)	4%	4%	4%	3%	3%	n/a	4%	5%
SDG&E	**Allocated Capacity** (% of Total Contract Capacity)	20%	18%	21%	20%	25%	n/a	19%	19%
	Allocated Energy (% of Total Contract Energy)	18%	18%	19%	20%	22%	n/a	17%	17%
	Residual Net Short (% of IOU Load)	9%	8%	6%	8%	4%	n/a	16%	11%

SCE & SDG&E Combined (Additive of Independent Analysis - Not Optimized)	**Allocated Capacity** (% of Total Contract Capacity)	61%	57%	57%	57%	57%	63%	53%	57%
	Allocated Energy (% of Total Contract Energy)	60%	58%	58%	58%	57%	62%	56%	59%
	Residual Net Short (% of IOU Load)	7%	8%	8%	8%	10%	n/a	10%	8%
	Must-Take Surplus (% of IOU Load)	4%	3%	3%	3%	4%	n/a	4%	4%

Notes: Allocated energy including dispatchable energy production, residual net short and surplus energy based on estimating utilization of contracts by each utility independently using deterministic hour-by-hour analysis. Percentages may not add to 100% due to rounding.

Assessment of Power Costs

(Summary of 7-Year Average - 2003 through 2009)

7-Year Average		DWR Support Analysis (July 26th Workshop)					Utility Proposals (July 19th Filings)		ALJ Alternate (July 26th)
		Straw Man	**Option 1A**	**Option 1B**	**Option 2A**	**Option 2B**	**PG&E Proposal** (July 19th)	**SCE and SDG&E Proposal** (July 19th)	
PG&E	**Costs Follow Contract** (Nominal $000's)	$1,572,479	$1,682,527	$1,682,527	$1,674,375	$1,674,375	$1,462,490	$1,821,548	$1,659,386
	Costs Follow Contract ($/MWh)	$70.80	$71.50	$71.50	$71.56	$71.56	$70.70	$72.06	$71.13
	Pro-Rata Cost Allocation (Nominal $000's)	$1,555,886	$1,648,155	$1,648,155	$1,639,499	$1,639,499	$1,449,101	$1,771,223	$1,634,498
	Pro-Rata Cost Allocation ($/MWh)	$70.05	$70.05	$70.05	$70.05	$70.05	$70.05	$70.05	$70.05
SCE	**Costs Follow Contract** (Nominal $000's)	$1,713,681	$1,591,963	$1,536,860	$1,542,951	$1,403,449	n/a	$1,635,419	$1,664,115
	Costs Follow Contract ($/MWh)	$68.01	$67.31	$67.33	$66.76	$70.34	n/a	$67.18	$68.07
	Pro-Rata Cost Allocation (Nominal $000's)	$1,762,357	$1,648,688	$1,595,429	$1,599,658	$1,396,658	n/a	$1,702,660	$1,711,373
	Pro-Rata Cost Allocation ($/MWh)	$70.05	$70.05	$70.05	$70.05	$70.05	n/a	$70.05	$70.05
SDG&E	**Costs Follow Contract** (Nominal $000's)	$784,308	$795,978	$851,080	$853,141	$992,644	n/a	$613,500	$746,966
	Costs Follow Contract ($/MWh)	$73.05	$72.01	$71.76	$71.50	$66.26	n/a	$71.85	$71.79
	Pro-Rata Cost Allocation (Nominal $000's)	$752,225	$773,625	$826,884	$831,310	$1,034,310	n/a	$596,584	$724,596
	Pro-Rata Cost Allocation ($/MWh)	$70.05	$70.05	$70.05	$70.05	$70.05	n/a	$70.05	$70.05

SCE & SDG&E Combined	**Costs Follow Contract** (as a % of Total)	61%	59%	59%	59%	59%	64%	55%	59%
	Pro-Rata Cost Allocation (as a % of Total)	62%	60%	60%	60%	60%	64%	56%	60%

Note: Energy production and contract costs based on PROSYM Run35. Allocated power costs do not include ancillary service costs, balancing accounts/charges and offsets from sales surplus energy which are also part of the total revenue requirement.

Assessment of Above Market Costs (Analysis by SCE)

(Present Value of Above Market Costs – as Calculated by SCE)

Above Market Costs "AMC" (as calculated by SCE in their July 24th public document and August 5th filing)		**DWR Support Analysis** (July 26th Workshop)					**Utility Proposals**			**ALJ Alternate** (July 26th)
		Straw Man	**Option 1A**	**Option 1B**	**Option 2A**	**Option 2B**	**PG&E Proposal** (July 19th)	**PG&E Option B 1]** (July 30th)	**SCE and SDG&E Proposal** (July 19th)	
PG&E	**Present Value of AMC** (as a % of Total)	38%	43%	43%	43%	43%	37%	42%	46%	42%
SCE	**Present Value of AMC** (as a % of Total)	40%	37%	42%	33%	37%	n/a	42%	37%	40%
SDG&E	**Present Value of AMC** (as a % of Total)	21%	20%	15%	25%	20%	n/a	17%	17%	18%
SCE & SDG&E Combined	**Present Value of AMC** (as a % of Total)	62%	57%	57%	57%	57%	63%	58%	54%	58%

Percentages may not add to 100% due to rounding.

Note: Assessment of Above Market Costs (AMC) as calculated by SCE in their July 24th public document and August 5th filing.