Decision **PROPOSED DECISION OF ALJ PULSIFER** **(Mailed 5/20/2003)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060.	Rulemaking 02-01-011 (Filed January 9, 2002)

(See Decision (D.) 02-11-022 for a list of appearances.)

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OPINION

I. Introduction

In this decision, we determine the appropriate level of the Direct Access (DA) cost responsibility surcharge (CRS) cap effective for the period subsequent to July 1, 2003. In Decision (D.) 02-11-022, we adopted an interim DA CRS cap of 2.7 cents/kWh pending further proceedings that have led to the instant order. Based on further study as directed in that decision, we conclude that the existing 2.7 cents/kWh cap should continue in effect beyond July 1, 2003. We conclude that the dual goals of bundled customer indifference and DA viability are balanced by continuing the existing level of the cap subsequent to July 1, 2003, subject to provision for continued monitoring and periodic readjustment, as needed to assure bundled customers are made whole on a timely basis.

In D.02-11-022, we adopted policies and procedures to implement cost responsibility surcharges for DA load pursuant to the directives in D.02-03-055, as modified and affirmed in D.02-04-067, which maintained the effective date of September 21, 2001 for the suspension of DA that was adopted in D.01-09-060, as affirmed in D.01-10-036. We suspended DA pursuant to legislative directive, as set forth in Assembly Bill No. 1 from the First Extraordinary Session (AB 1X). (See Stats. 2002, 1st Extraordinary Session, ch 4.) This emergency legislation was enacted and made effective on February 1, 2001 to respond to the serious situation in California when Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) became financially unable to continue purchasing power due to extraordinary and unforeseen increases in wholesale energy prices.

The Governor's Proclamation of January 17, 2001,[1] and AB 1X required that DWR procure electricity on behalf of the customers of the California utilities. As part of its provisions to deal with California's energy crisis, AB 1X also called for the suspension of the right to acquire DA, as set forth in Section 80110 to the Water Code:

> "After the passage or such period of time after the effective date of this section as shall be determined by the commission, the right of retail end use customers pursuant to Article 6 … to acquire service from other providers shall be suspended until [DWR] no longer supplies power hereunder."

In compliance with the mandate to suspend DA, we considered the related implementation issues in A.98-07-003. The Commission issued D.01-09-060, suspending the right to acquire DA after September 20, 2001. In D.01-09-060, we placed parties on notice, however, "that we may modify this order to include the suspension of all direct access contracts executed or agreements entered into on or after July 1, 2001." (D.01-09-060, pp. 8-9.)

On January 14, 2002, the instant rulemaking (R.) 02-01-011 was initiated to consider among other things, whether a suspension date earlier than September 20, 2001 should be applied to direct access.[2] On March 27, 2002, we issued D.02-03-055, determining that the DA suspension date should remain as

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[1] On January 17, 2001, Governor Davis issued a Proclamation that a "state of emergency" existed within California resulting from unanticipated and dramatic wholesale electricity price increases.

[2] The administrative record relating to these specific issues in A.98-07-003 et al. was incorporated into this rulemaking. Judicial notice was also taken of specific information in the DWR Revenue Allocation Proceeding A.00-11-038 et al. (See Letter of January 25, 2002, to the parties that accompanied the Draft Decision of ALJ Barnett).

"after September 20, 2001." DA contracts executed on or prior to September 20, 2001, were not suspended, but were made subject to the restrictions imposed by D.02-03-055. We emphasized in D.02-03-055 that bundled service customers should not be burdened with any additional costs due to the migration of customers from bundled service to direct access between July 1, 2001 and September 21, 2001.

We stated that, in lieu of an earlier suspension date of July 1,2001, DA surcharges must be adopted as a means of preventing cost shifting to bundled customers. We later clarified that prevention of cost shifting meant that "bundled service customers are indifferent."[3] In order to maintain bundled customer indifference, DA customers must thus bear cost responsibility for stranded costs due to the migration of customers from bundled to DA service on and between July 1 and September 20, 2001.

In D.02-11-022, we adopted a methodology for achieving bundled customer indifference through a Direct Access Cost Responsibility Surcharge (DA CRS). In adopting the DA CRS mechanism, we noted our concern that had been previously expressed in D.02-07-032 that the "pancaking" of cumulative surcharges on DA customers may lead to DA contracts becoming uneconomic. To address this concern, we stated in D. 02-07-032 that "there should be a cap on the total surcharge levels imposed on DA customers (including the impact of any changes to PX credits)."

Consistent with these concerns expressed in D.02-07-032, we did not immediately pass through the full DA CRS obligation, including cumulative undercollections, to DA customers. To avoid undermining the economic viability of DA, we adopted an interim cap of 2.7 cents/kWh on the current DA CRS amounts billable to DA customers to remain in effect through July 1, 2003 pending further study.

The DA CRS includes the DWR Bond and Ongoing Power Charge applicable to DA load that took bundled service on February 1, 2001, and a charge on all DA load for above-market Utility Retained Generation (URG) costs.[4] For SCE, the amount collected under the DA CRS cap also includes the Historical Procurement Charge (HPC) to recover a part of the Procurement Related Obligation Account (PROACT) balance from DA customers pursuant to D.02-07-032.[5]

The DA CRS cap is intended to preserve bundled customer indifference while avoiding economic harm to customers. By imposing a cap on the initial payment obligation, the burden of the DA customer is mitigated. DA customers remain responsible for the deferred DA CRS obligation in excess of the cap, but the collection is spread over future periods. Bundled service customer charges

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3 D.02-04-067, pp. 4-5 (slip op.).

4 The Bond Charge became "billable" when D.02-11-022 became final and unappealable when the California Supreme Court summarily denied the petition for writ of review in Strategic Energy, LLC v. Public Utilities Commission of the State of California, Case No. S112802S, on April 30, 2003. The Bond Charge component of the DA CRS had been tracked in a memorandum account.

In addition to the nonbypassable charges that were part of R.02-01-011, DA customers are still responsible for other charges, including Public Purpose Program Charge, Nuclear Decommissioning Charge and Trust Transfer Amount (TTA) for DA customers under 20 kW.

5 PROACT is the account established as part of SCE's Settlement with the Commission which records an initial level of unrecovered costs. (See D.03-02-035; see also, Resolution E-3765 (January 13, 2002), p. 13.)

fund CRS undercollections due to the cap on an interim basis pending reimbursement from DA customers.

The DA CRS undercollection shall be paid off in subsequent years as revenues collected under the capped DA CRS begin to exceed then-current DA revenue requirements. The resulting surplus in DA CRS recovery in later years will be credited to bundled customers, with interest, to pay down the undercollections that they funded in the initial years. In D.02-11-022, we ordered further proceedings to assess whether or to what extent the interim 2.7 cents cap was sufficient, or should be revised as of July 1, 2003, in order to assure proper balancing of the goals of bundled customer indifference and DA economic viability. This phase of the proceeding is addressing whether the 2.7 cents cap should be revised subsequent to July 1, 2003.

II. Procedural Summary

An ALJ ruling was issued January 24, 2003, setting the schedule for this phase, and defining the scope of issues to be addressed. Consistent with its obligations under the Rate Agreement, the California Department of Water Resources (DWR) provided modeling support in this phase of the proceeding through Navigant Consulting, Inc. (Navigant) for use in evaluating the potential effects of alternative DA CRS caps in terms of undercollections and payback periods.

A technical workshop was held on February 6, 2003 for the purpose of discussing the DWR/Navigant model and appropriate modeling scenarios to be performed as a basis for analyzing the DA CRS cap issue. The modeling scenarios and parameters discussed at the workshop served as a basis for the subsequent modeling runs performed by DWR/Navigant.

DWR served opening testimony on February 24, 2003 presenting the Navigant modeling runs, and explaining the inputs and methodologies used in developing various DA CRS cost responsibility forecast scenarios. The three utilities (PG&E, SCE and San Diego Gas and Electric Company (SDG&E) served concurrent testimony explaining the URG modeling inputs provided to Navigant. All parties submitted testimony in response to the DWR/IOU modeling testimony on March 19, 2003, and rebuttal testimony on March 26, 2003. Evidentiary hearings were held between April 1 – 7, 2003.

Parties filed opening briefs on April 22, 2003, and, reply briefs on May 6, 2003 on issues relating to the capping of cost responsibility charges on DA customers. Active parties in this phase of the proceeding included the investor-owned utilities (IOUs), parties representing bundled customers (i.e., Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), and the California Farm Bureau Federation (Farm Bureau);[6] parties representing DA customers, either through industry associations or as individual customers.

Active parties representing DA interests that sponsored testimony included the California Large Energy Consumers Association (CLECA), and California Manufacturers & Technology Association (CMTA); the Alliance for Retail Energy Markets and the Western Power Trading Forum (AREM/WPTF); the City of Corona, Strategic Energy, LLC; and the University of California and the California State University (UC/CSU).

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[6] The Farm Bureau is a voluntary, non-profit corporation with more than 90,000 members in California that expect to pay more than $850 million for electric service in 2003. Farm Bureau members are overwhelmingly bundled agricultural customers.

III. Framework for Evaluating the DA CRS Cap

As a framework for evaluating the appropriate level of the cap, we begin with recognition of the two overriding goals to be balanced: (1) maintaining bundled customer indifference with respect to DA migration and (2) avoiding making DA uneconomic to customers.

In evaluating the DA CRS cap with respect to bundled customer indifference, we first consider the criteria by which to assure that bundled customer indifference is preserved. By default, bundled customers absorbed stranded costs attributable to migrated DA load. D.02-03-055 set forth the requirement for bundled customer indifference. Time was required after issuance of D.02-03-055 to conduct further proceedings to implement a methodology and process to measure and bill DA customers for their share of cost responsibility. By the time that a DA CRS methodology was adopted in D.02-11-022, a significant undercollection had already accumulated attributable to DA CRS past obligations.

Bundled customer indifference must be accomplished, therefore, by providing a means for bundled customers to be made whole for these accumulated past undercollections as well as for ongoing stranded costs attributable to the DA CRS. Yet, if we were to require that DA customers immediately reimburse bundled customers for the entire past obligation plus prospective ongoing stranded cost requirements, the required increase in the surcharge on DA customers could seriously threaten the economic viability of DA as a continuing option.

Thus, in order to balance the countervailing goals of bundled customer indifference and preventing harm to DA, we devised an approach in D.02-11-022 whereby the DA obligation is paid off over time, subject to a cap limiting current DA CRS payments.

To preserve bundled customer indifference, any DA CRS cap must be high enough to assure bundled customers are fully reimbursed for any funds advanced over time, including interest, to cover the DA CRS undercollections. Counterbalancing this goal, any DA CRS cap should be set low enough so that the cumulative burden of all energy charges faced by DA customers do not render the DA option untenable.

The next step is to assess the level of (1) DA CRS undercollections already incurred and (2) likely future years' DA CRS obligations and related per-kWh charges yet to be incurred. For purposes of this assessment, forecasts have been performed by Navigant involving a range of scenarios as to the potential streams of DA CRS obligations over future years during which time bundled customers are funding a portion of the DA CRS obligation.

Based upon the assessment of these scenarios and the likely level of future DA CRS obligations, the appropriate level of cap can be calculated required to satisfy our dual criteria of preserving bundled customer indifference and avoiding making DA uneconomic. We thus balance the countervailing effects both on bundled and DA customers, so that the cap is neither too high nor too low.

IV. Relationship of this Proceeding to the DWR and CTC Revenue Requirement Proceedings

Parties express differing views concerning the scope of this phase of the proceeding and how it relates to the determination of the overall DWR revenue requirement for 2003 in A.00-11-038 et al., and to the finalization of the total revenue requirement for DA load, including CTC, applicable to the 2001-2002 undercollection and to the 2003 prospective revenue requirement for DA CRS elements. PG&E, in particular, views this phase as forum to adopt final values for those DA CRS elements. Accordingly, PG&E recommends that a final 2003 prospective DA CRS revenue requirement be determined in this phase of the proceeding using the same DWR analysis used to develop the DWR revenue requirement in A.00-11-038. PG&E calculates its DA CRS amount to be $381 million, and proposes that this amount be used to set its DA CRS obligation in this proceeding. PG&E also proposes adoption of CTC elements.

Other parties disagree that this phase of the proceeding is intended to adopt final DA CRS values, but rather view that process as subject to a separate phase to be coordinated with the DWR proceeding in A.00-11-038. Parties object to the proposed DA CRS values offered by PG&E and argue that further scrutiny of its proposal is warranted before any final charges are adopted.

We have previously stated that the DA CRS total obligation should be determined using consistent assumptions with the overall DWR revenue requirement in order to avoid a mismatch between the allocation of costs between bundled and DA customers. Yet, this phase of the proceeding is not focused on determining the precise amount of the total DA CRS obligation, but rather, on the appropriate cap to impose. These are two separate and distinct steps in the process. For purposes of assessing the appropriate cap, the most reliable and accurate estimates of relevant resource assumptions over time are more important than exact tracking with assumptions underlying the total DWR revenue requirement as determined in A.00-11-038. The appropriate time to focus on consistent matching of resource assumptions between the DA CRS and DWR revenue requirement is in the phase of the proceeding where we actually determine the total DA CRS obligation for the 2001-2003 period in parallel with the total DWR revenue requirements determined in A.00-11-038. We shall address, quantify, and implement the total DA CRS DWR obligation for the period from 2001 through 2003 utilizing consistent resource assumptions with the DWR revenue requirements determination in A.00-11-038. We direct the ALJs in both of these proceedings to coordinate, as required, to implement this process expeditiously.

We affirm that this phase of the proceeding is focused on setting the DA CRS cap. Thus, we use the data presented in this proceeding to assess longer term conditions as a basis to set an appropriate DA CRS cap. The finalization of the actual DWR and URG revenue requirement elements is a separate exercise that must be closely coordinated with the DWR proceeding in A.00-11-038 et al. A separate determination is also required of the actual recorded undercollection applicable to the DA CRS for the historic period from September 20, 2001 through December 31, 2002.

In addition to the DWR component, we must finalize and adopt amounts for the URG component of the DA cost responsibility obligation. Since the DWR proceeding in A.00-11-038 et al. does not address URG costs, a separate process is needed to examine URG costs and to adopt a CTC component as prescribed under the total portfolio approach prescribed in D.02-11-022.

The ALJ's Proposed Decision designated the Energy Resource Recovery Account (ERRA) proceeding for determination of the final CTC revenue requirement. ORA opposes the use of the ERRA proceeding for litigating the final CTC values. ORA argues that the complexity of CTC issues will require additional time to litigate, and will compromise the goal of timely processing of these proceedings as called for in Public Utilities Code Section 454. 5. As an alternative, ORA suggest placing the CTC issues in the Annual Transition Cost Proceedings, or else to open a new proceeding.

PG&E opposes litigating its 2003 CTC revenue requirement in the ERRA proceeding. PG&E argues that the limited schedule for completing the ERRA prior to the end of 2003 will not accommodate litigating the 2003 ongoing CTC revenue requirement. The current ERRA proceeding was filed on February 3, 2003. PG&E contends that the proceeding should not be slowed down to incorporate the 2003 ongoing CTC. If the Commission chooses to litigate this issue further, in spite of the record already developed here, PG&E argues that a separate proceeding should be held as quickly as possible to set this rate component and revenue requirement.

PG&E agrees that the ongoing CTC revenue requirement and rate component for 2004 could be established in the ERRA proceeding. PG&E argues that determination of the ongoing CTC in the ERRA, however, should not be allowed to keep that proceeding from reaching conclusion by the end of 2003. PG&E's ERRA revenue requirement for 2004 will be presented in its August 1, 2003, filing, thus leaving five months to complete the ERRA proceeding before the end of the year.

SCE does not oppose litigating its CTC component in the ERRA proceeding, but notes that the currently defined scope of its ERRA is limited to 2003 fuel and purchased power costs. If CTC is addressed in the ERRA, SCE seeks authorization to augment its showing in that proceeding to introduce additional evidence relating to its total URG. SCE still prefers that the historical URG costs for 2001 and 2002 be considered in this proceeding. If the Commission, however, directs that even the CTC for the 2001-02 period be considered in the ERRA proceeding, SCE would need to supplement the record with data relating to that recorded period.

In view of the time constraints involved, we conclude that the final determination of the CTC component for 2003, as well as the historic CTC for 2001-02, for each utility should be finalized in a separate phase of this proceeding, rather than in the ERRA. Given the requirement to ensure timely recovery of procurement costs in the ERRA proceeding as prescribed in Section 454.5, we recognize that it could delay timely completion of that proceeding if additional issues relating to 2001-03 CTC were added to the scope.

As noted above, we have prescribed that the DWR power charge component of the DA CRS for the 2001-02 historic periods and 2003 prospective period shall be determined in this proceeding on a parallel track with the redetermination of the DWR revenue requirement being litigated in A.00-11-038 et al. Accordingly, we shall direct that the final determination for CTC for the 2001-02 historic period and prospectively for 2003 be addressed at the same time in this docket. The concurrent finalization of both the DWR and URG components of the DA CRS should facilitate adopting a final cost responsibility obligation for DA and Departing Load through 2003, including confirmation of the final 2001-02 undercollection balance.

For subsequent years beginning with 2004, we conclude that prospective determination of the CTC for each utility can be accommodated within the ERRA proceeding.

SCE seeks guidance as to whether assume the use of the 4.3 cents/kWh benchmark for CTC adopted in D.02-11-022 for every year from 2001 through 2003, or to update the figure in the ERRA proceeding. Since it was the intent in D.02-11-022 to adopt the 4.3 cents/kWh as an initial benchmark for use in determining above-market resource costs, parties should apply this value for computing CTC for the years 2001 through 2003. For the year 2004 and subsequent years, the 4.3 cents benchmark will be subject to revision to reflect more updated data.

While DWR used its base case assumptions from its previous DWR revenue requirements filing as a point of departure for modeling scenarios, we are not bound by those assumptions for our purpose here which is a multi-year assessment of DA CRS based upon the best information available. Accordingly, we do not adopt final figures for DWR or CTC revenue requirements for any of the utilities in this phase of the proceeding. We do establish a specific process, however, as outlined above to assure that final figures are adopted on a timely basis in coordination with A.00-11-038 et al.

V. Results from Modeling and Forecasting of DA CRS Levels

To provide a framework for analysis of potential future DA CRS obligations and the resulting effects of alternative caps, Navigant produced a range of separate modeling scenarios, incorporating the "total portfolio indifference" approach.[7]

In response to requests from parties for a range of forecast sensitivities in key variables, DWR/Navigant modeled three separate cases. These cases

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[7] The "total portfolio" indifference approach as adopted in D.02-11-022 incorporates the total costs of serving bundled customer load both from DWR and URG sources, and solves for the DA CRS required to keep bundled customers indifferent between a DA suspension date of July 1 versus September 20, 2001. The DA CRS is based on ProSym model runs on a DA-in versus DA-out comparative basis.

identified key resource variables under a "base case" corresponding to the variables underlying DWR's revenue requirement analysis for 2003. DWR then separately modeled a "high and low case" incorporating variations in key variables. The key resource assumptions subject to sensitivity testing among the three ProSym cases are as follows:

Key Variables in the DWR/Navigant sensitivity analysis

Future DA Load:	High Case Assumes 10% higher than Base Case Low Case Assumes 30% lower than Base Case
Natural gas prices:	High Case Assumes 25% lower than Base Case Low Case Assumes 20% higher than Base Case
New Generation:	High Case Assumes 20% higher than Base Case Low Case Assumes 20% lower than Base Case
CTC Benchmark:	High Case Assumes 15% lower than Base Case Low Case Assumes 15% higher than Base Case

The assumed range of differences in the variables among the three ProSym cases was arrived at through consensus among the participants at the Navigant modeling workshop. For each of the ProSym cases (i.e., high, low, and base), Navigant applied additional varying assumptions concerning OSS prices, interest rate accruals, and cap levels. Alternative combinations of the variables were assembled into eight possible scenarios. The eight scenarios were run under each of the three ProSym cases to produce 24 separate scenarios (i.e., eight combinations times three ProSym cases) for each utility.

The scenarios illustrate the effects of changing the following key variables: offsystem sales (OSS) price (at either 50% or 100% of market-clearing price[MCP]), interest rate on cumulative uncollected CRS balance (bounded between 4% and 9%), and the DA CRS cap (either at 2.7 cents or 4 cents/kWh). Appendix A summarizes the key results for each of the 24 assumed modeling scenarios for each utility. To assist in evaluating the effects of each scenario under the alternative cap levels on bundled customers, Navigant computes the maximum undercollection reached and years that would be required to pay off the accumulated undercollection.

In its modeling runs that Navigant produced in the earlier phase of this proceeding leading to D.02-11-022, the forecast DA CRS for SDG&E was significantly higher than that for PG&E or SCE. The difference was due mainly to the fact that SDG&E held a higher percentage of the highest-cost DWR contract power in its portfolio mix. In the current modeling performed in this phase of the proceeding, however, SDG&E has the lowest DA CRS requirements compared to PG&E and SCE.

In the most recent modeling scenarios for this phase, however, the payback period and undercollections for SDG&E are forecast to be the shortest among the three utilities. The change in SDG&E's relative situation since issuance of D.02-11-022 is due to revised assumptions underlying the effective date for applying the DA CRS. In earlier model runs supporting the record underlying D.02-11-022, Navigant assumed an effective date of July 1, 2001 for applying the DA CRS. In D.02-11-022, however, the Commission adopted an effective date of February 1, 2001 for assessing DA CRS. Consequently, Navigant has reflected this modified assumption in its modeling runs performed for this phase of the proceeding. The aggregate level of DA cost responsibility, however, continues to be based on maintaining bundled customer indifference between the change in DA load between July 1 and September 20, 2001. The substitution of the earlier effective date thus results in an increased volume of DA load absorbing the same fixed DA CRS obligation.

Consequently, by spreading the cost obligation over a greater volume of DA load, the per-kWh DA CRS declines and the projected DA CRS payback period for bundled customers occurs sooner compared with the earlier model runs. The reduced unit cost and earlier payback is more pronounced for SDG&E compared to PG&E and SCE because SDG&E's volume of DA load between February 1 and July 1, 2001 changes the most.

DWR states that the version of the model submitted in this proceeding, incorporates actual values for most of the volumes and costs from the fourth quarter of 2001 (when the DA CRS obligation first began to accrue) through the end of December 2002. Independent System Operator (ISO) charges did not reflect recorded values since they are lagged by 90 days. ISO charges represent only a small percentage of total charges. DA load values used by DWR for 2001 and 2002 reflect estimates received from the utilities. DWR has requested actual DA load data from each of the utilities.

Because there was no DA CRS in effect prior to January 1, 2003, the accrued DA CRS obligation from September 20, 2001 forward represents an accumulating undercollection due from DA customers. In its modeling scenarios, however, DWR did not quantify the actual undercollection applicable to DA CRS for 2001-02, but merely presented a range of hypothetical undercollections through 2002 corresponding to the scenario assumptions used to calculate the year 2003 DA CRS. Navigant applied the percentage ratio of DA in / out differences for each of its 2003 forecast scenarios to the historic 2001-2002 costs. This approach assumes that the DA-in / out scenario forecasts for 2003 apply equally to the 2001-2002 historic period. We discuss the problems with this approach below.

VI. Determination of Cap Levels

A. Overview of Positions of Parties

PG&E's primary criterion for setting any cap is to ensure DA CRS payback by the expiration of the DWR contract term in 2011. PG&E argues that the DA CRS shortfall should be recovered as quickly as possible to minimize risk to bundled customers, and tying the payback duration to DWR contract length is consistent with approach applied to CTC recovery in AB 1890. PG&E thus proposes that the cap be set at 4 cents/kWh based on its analysis that full payback to bundled customers of the DA CRS obligation can thereby be achieved by 2011. PG&E's recommendation for a 4 cents cap is predicated on the Navigant base case run that assumes Off System Sales (OSS) at only 50% of Market Clearing Price (MCP). If the Commission concludes that a different scenario or set of forecast assumptions are more reasonable that would still enable the DA CRS shortfall to be paid off by 2011 with a cap lower than 4 cents, then PG&E agrees that such a lower cap should be considered. PG&E recommends that the DA CRS assumptions used be consistent with those DWR uses to develop the 2003 DWR power charge revenue requirement. For 2003, PG&E calculates the DA CRS indifference amount to be $310 million.

SCE proposes an increase in the cap to 3 cents/kWh, with the provision for further increases thereafter if the DA CRS undercollection for SCE ever exceeds $500 million. SCE believes its proposal would avoid making DA uneconomic and would achieve payback by 2011 when most DWR contracts expire. SCE's proposed assumptions for evaluating the cap correspond most closely to DWR's Base Case Scenario 5, which assumes a 100% Market Clearing Price (MCP) for excess energy sales, and a 9% interest rate. Under Scenario 5, SCE is predicted to accumulate a maximum undercollection of $498 million and to recover the undercollection by year 2010. SCE's proposes to recover the undercollection as quickly as possible, but in no event extending beyond 2011. Using Scenario 5 as a guide, therefore, SCE recommends increasing the DA CRS cap to 3.0 ¢/kWh to guard against a High Case CRS scenario occurring

(Scenario 21), which would create a maximum undercollection of $674 million for SCE.

SDG&E supports continuation of the 2.7 cents cap, and believes that DA CRS undercollections resulting from the current cap will be manageable and permit payback within a reasonable timeframe. SDG&E believes that Scenario 6 incorporating the Base Case with OSS at 100% of MCP at a 4% interest rate reflects the most realistic set of assumptions for forecasting multi-year DA CRS impacts.[8] SDG&E warns that there is a substantial, immediate risk in setting the cap too high, in that once DA viability is impaired, perhaps even modestly, parties and the Commission may not realize the harm until it is too late—"when DA customers' businesses evaporate, relocate, or are emaciated sufficiently that they cannot pay their electricity bills in due course." (See Exh. 181, p. 6.)

TURN's primary position is that no cap be permitted unless it is financed by DWR bonds rather than by bundled ratepayers. TURN believes that imposition of any CRS cap with bundled ratepayer financing of the shortfall results in cost shifting in violation of the intent underlying AB 117. Assuming that the Commission chooses to continue imposing some level of cap, however, TURN proposes that its duration be as short as possible. In any event, TURN argues that all outstanding DA CRS obligations due to bundled customers

[8] The scenario modeling for SDG&E was initially done on a dual basis showing alternate results due to uncertainty as to whether 80 MW of United States Navy load was deemed to be exempt from the DWR components of the DA CRS. The Commission subsequently issued D.03-05-036 on May 9, 2003, affirming that the 80 MW of Navy load is indeed subject to the DWR charges. Accordingly, the treatment adopted in D.03-05-036 is incorporated into the modeling runs relied upon for purposes of analysis of the appropriate cap in this decision.

should be fully repaid within the term of the DWR contracts, which expire in 2010 or 2011.

TURN believes that the existing undercollections should not be allowed to grow any larger. TURN proposes that the CRS cap be set at least high enough to recover current year CRS charges even if there is no immediate recovery of the undercollections already accrued. To meet these conditions, TURN argues that the cap must be set at no less than 4 cents/kWh. TURN expresses concern that any lower cap would create an unacceptable risk that bundled customers would never be repaid. TURN also contends that now is the better time to collect DA CRS costs rather than later since bundled rates are still quite high for all of the utilities.

ORA supports the proposals of PG&E and SCE to increase the cap to 4 cents for PG&E, and 3 cents for SCE. ORA believes these cap levels address the risks associated with what it characterizes as an involuntary loan that bundled customers must bear. ORA also believes that a cap of 3 cents for SDG&E "may be justified" because SDG&E's retail rates are currently closer to those of SCE than of PG&E. ORA takes no position favoring any one Navigant scenario over another, but objects to DA parties' general characterizations of DWR's forecasts as being overly "conservative" in order to satisfy bondholders. ORA argues that DWR's witness characterized the forecasts as a "best guess" that were not biased.

Farm Bureau represents approximately 90,000 members in California that are overwhelmingly on bundled service. Farm Bureau proposes replacing the current DA CRS with two separate components: (1) a "Local Utility" (LU) surcharge consisting of CTC that would be levied without being subject to a cap, and (2) a DWR surcharge consisting of DWR bond charges and going-forward charges that would be capped at the current level of, which would be capped at

2.7 cents. Farm Bureau originally proposed the LU surcharge include the HPC (for SCE only), but now proposes that SCE's 2.7¢/kWh cap include the HPC.

Under this approach, the current DA CRS cap would be separated out prospectively to acknowledge the responsibility of all customers for CTC payments.[9] Farm Bureau argues its proposal offers shorter payback periods, and thus greater intertemporal equity for both bundled and DA customers. If its proposal to bifurcate the surcharge is denied, Farm Bureau supports a 4 cent per kWh cap. Farm Bureau argues that segregating the surcharge into two components simplifies the administration of a cap on collection of the shortfall.

Farm Bureau argues that except for a somewhat low gas forecast, the base case provides the best tool to analyze impacts from the OOS and interest rates on varying cap levels. Nonetheless, Farm Bureau believes that no one particular scenario is reliable enough to form the basis for establishment of a cap. To the extent a particular scenario is selected, Farm Bureau believes the base case should be used with a 75% Off System Sales factor.

Parties representing DA interests propose no change in the existing 2.7 cents cap. CLECA witness Barkovich believes that the existing cap will yield a payback period of less than 10 years under the most reasonable set of assumptions underlying the Navigant modeling scenarios. CLECA believes that both URG and DWR forecasts are overstated, and that accordingly, the actual DA CRS payback period will be considerably less than Navigant's forecasts indicate.

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[9] Competition Transition Cost (CTC) was identified in D.02-11-022 as the URG-related component of the DA CRS.

CLECA argues that raising the cap as high as 4 cents would render many DA contracts uneconomic.

AREM likewise argues that the current 2.7 cents cap can be maintained while keeping DA undercollections to a minimum and achieving payback of the DA CRS obligation within three to five years, depending on the utility involved. AREM based its analysis on a hybrid approach that it calls "Scenario 25." This hybrid combines the gas price, market entry, and CTC assumptions from the ProSym low case with the DA penetration rate assumptions from the ProSym base case. AREM also assumes a 100% MCP and an average interest rate based on three-month commercial paper.

Strategic Energy believes that Scenario 14, incorporating the "low" ProSym case and OSS priced at 100% of MCP, represents the most likely set of assumptions modeled by Navigant. Strategic Energy argues that this scenario provides for payback within eight years or less under the existing 2. 7 cents cap. Strategic thus advocates no change to the existing cap, but expresses the concern that even under the current 2.7 cents cap, DA customers are experiencing a serious fiscal impact.

CMTA believes that Scenarios 6 and 14 are the most plausible of those presented by Navigant. The only difference between these two scenarios is that Scenario 6 represents the base case while Scenario 14 represents the low case. Between Scenario 6 and 14, the longest payback period is forecast to be between eight and 11 years for PG&E.

CMTA opposes linking the cap to a required payback of the undercollection by the end of the DWR contract term or to any maximum permissible undercollection level. CMTA argues that in numerous cases, the collection of revenues authorized by the Commission is not concurrent with the incurrence of costs. For example, the DWR Bonds will not be paid off before the end of the DWR contract term in 2011. CMTA also disputes the claim that a higher cap is needed now to accelerate the payback period and thereby reduce bundled customers' risk of default. CMTA argues that an immediate increase in the cap could drive some DA customers out of business and exacerbate the risk even more that those customers would not contribute toward paying off the undercollection.

B. Discussion

As a basis for setting an appropriate cap, we first address the appropriate criteria to balance the dual goals of bundled customer indifference and avoiding economic harm to customers. We next consider the range of DA CRS forecast scenarios and their relative likelihood of being accurate. Then, based upon our assessment of the most likely range of forecasts, we determine the level of cap for each utility required to satisfy our identified criteria.

We find that it is not necessary to raise the cap at this time in order to satisfy our adopted criterion, as explained below, of ensuring payback of the undercollection by the end of the DWR contract term. Likewise , we find no basis to lower the cap below its existing level. While increasing the cap to as much as 4 cents/kWh would accelerate the payback to bundled customers even sooner, it could also risk economic harm to DA customers. As we determined in D.02-03-055, there are benefits to the State of California as a whole resulting from the continuation of the DA program. The benefits of DA include more jobs for Californians and a stronger tax base as well as diversification of California energy supplies. By avoiding making DA uneconomic, these benefits to the public as a whole can continue. As discussed further below, we conclude that avoiding economic harm to DA is reasonably balanced against bundled customer interests by keeping the 2.7 cents cap at least until the next periodic reassessment.

Accordingly, we shall retain the existing 2.7 cents cap in place for each utility continuing beyond July 1, 2003, pending review in the next reassessment proceeding as discussed below. By providing for periodic reassessment of the cap, we mitigate any risk related to the forecasts deviating from actual results. By providing for timely midcourse corrections and periodic readjustments of the cap to ensure payback by 2011, we protect bundled customers even to the extent the current forecasts underlying the base case subsequently prove less reflective of future conditions. The cap can be periodically adjusted, as needed, to reflect updated forecast data so that full repayment occurs no later than the end of the DWR contract term in 2011.

We decline to adopt the Farm Bureau recommendation to bifurcate the cap into two components. Such an approach would unduly complicate the administration of the cap. By retaining all of the existing elements under a single cap, we can evaluate the effects of DA viability on a more integrated and comprehensive basis.

1. Cap Criteria for Assuring Bundled Customer Indifference

As mentioned above, our criteria for setting a cap must preserve bundled customer indifference. To meet this goal, we must provide assurance that undercollections from DA customers resulting from the cap will be repaid in full to bundled customers, with compensatory interest, over a reasonable period of time. We conclude that a reasonable time period for full repayment of the DA CRS undercollection should not exceed the term of the DWR contracts, due to expire in 2011.

We disagree with those parties that claim there is no reason to tie the duration of DA CRS repayment to any particular term, including the duration of the DWR contracts. As a general principle of regulation, it is desirable to charge customers based on the costs to serve them, thereby matching customer charges with the costs of service rendered to serve them. There are sometimes unusual situations, however, where the matching of costs incurred with service rendered is problematic. Due to the extraordinary magnitude of the DWR contract costs incurred during 2001, for example, current customers were not charged for the full level of such costs. The unrecovered portion was deferred to future periods and financed through long-term bonds.

Similarly, a portion of DWR power charges that are not financed by the DWR bonds result in an additional extraordinary cost responsibility attributable to DA customers. In the interests of preserving DA as a viable economic option, it is appropriate to defer some portion of the full obligation of such power charges by financing them through the DA CRS cap. Nonetheless, in order to balance this goal against the requirement of bundled customer indifference, the period of deferral should be no longer than is absolutely necessary. The fact that a portion of DWR costs incurred during 2001 are being financed over the life of DWR Bonds is not a precedent or rationale for extending the repayment period for the DA CRS undercollections beyond the minimum term that is absolutely necessary.

Requiring repayment of the DA CRS undercollection within the DWR contract time frame promotes better matching of costs paid with service rendered. Since the costs in question arise from the contracts, the time frame for their repayment bears some relationship to the term of those contracts. Limiting the repayment to the term of the contracts is also desirable to minimize the period that bundled customers fund any DA CRS undercollections so as to mitigate bundled customer risk. The lower the cap, the longer the time for repayment of the undercollection, and the greater the risks imposed on bundled customers relating to repayment. Accordingly, we shall adopt the requirement that the caps be set at level that assures full repayment of the DA CRS undercollection no later than the termination of the DWR contracts in 2011.

With the term limitation on the repayment period in place, we do not find it necessary to adopt a specific dollar figure at this time for a maximum cumulative DA CRS undercollection. An arbitrary DA CRS undercollection limit has limited meaning or basis for evaluation in isolation. A more relevant criterion would be the maximum increase in bundled customer charges that would be allowable resulting from financing DA CRS undercollections. No party has offered a specific proposal in this phase based on a specific maximum permissible bundled customer charge increase as a criterion for measuring the cap. While we adopt no specific figure at this time for the maximum percentage increase in customer charges attributable to the financing of the cap, we reserve the option to revise the cap, as deemed necessary in subsequent periodic reviews, in order to prevent unreasonable increases in the level of bundled customer charges.

2. Evaluation of Forecast DA CRS Payback Period Scenarios

We next turn to the question of the likely level of DA CRS over time as a basis to measure the payback period under alternative cap scenarios. As previously discussed in D.02-11-022, we remain cognizant of the limitations and caveats inherent in drawing inferences from multi-year forecasts. As the time horizon extends further into the future, the potential for unforeseen events and variances in forecasting grows. This uncertainty, in turn, has implications for the risks associated with the manner and timing of repayment of the CRS funds advanced by bundled customers.

While forecasts of DA CRS obligations will always be subject to the uncertainties of future years' conditions, however, the scenarios presented by Navigant still provide a basis for informed judgment concerning the expected payback period and levels of undercollection faced by bundled customers. For purposes of our analysis, we consider the effects of alternative caps on the risk, duration, and magnitude of payback of DA CRS undercollections.

In this context, Navigant's 24 scenarios represent a range of potential outcomes to evaluate forecasting sensitivities, rather than as a basis to precisely determine the future level of DA CRS costs and revenues. The range of sensitivities can be weighted in the form of a probability distribution. The fact that we cannot precisely predict the future thus does not preclude making informed judgments about the relative likelihood of future trends based upon facts known today. We thus conclude that some forecast scenarios have a greater likelihood of reflecting reality than do others. Thus, we give greater weight to some scenarios than to others as a basis for assessing the DA CRS payback period and undercollection level.

Parties offered little or no support for the high case scenarios produced through by Navigant as likely outcomes or guides for evaluating the cap. Some parties favored the base case assumptions while others favored the low case, or a hybrid of low and base case assumptions.

PG&E defends the base case because DWR used it in preparing its 2003 DWR revenue requirements in A.00-11-038 . The mere fact that the base case was used for the DWR revenue requirement, however does not justify reliance upon it here. PG&E offers no independent analysis of the reasonableness of DWR's base case assumption, but believes consistency is needed between the resource assumptions underlying the DWR proceeding and this proceeding. PG&E's support for the base case appears to assume that this phase of the proceeding is about setting the total DA CRS revenue requirement.

We agree that consistency with the DWR revenue requirement proceeding is warranted for purposes of determining the total DA CRS revenue requirement obligation for past periods through 2003. When we undertake that process, we shall ensure that consistent assumptions are used. This phase of the proceeding, however, is focused instead on evaluating the appropriate DA CRS cap. For that purpose, we seek the most realistic forecasts over the payback period. No useful purpose is served by relying on less reliable assumptions merely because they appear in DWR's base case.

Moreover, since we are not setting a total revenue requirement in this phase, the inputs that the utilities have provided concerning CTC are relevant here for the purpose of evaluating long term DA CRS forecasts, incorporating CTC costs into the total portfolio indifference calculation. We do not approve or adopt the CTC figures offered by PG&E as final figures nor prejudge any further review of the utilities' CTC as discussed previously.

We also conclude that an assumption of an off-system sales price of 100% of market clearing price (MCP) much more closely reflects likely expected results than an assumption of 50% on a prospective basis. Out of the 12 Navigant scenarios that incorporate the 100% OSS assumption, 10 of them result in full repayment of the undercollection within 10 years. Those scenarios assuming a 50% MCP level do not reliably reflect forecast results. The results from the low case with a 100% of MCP assumption for OSS and a 2.7 cents cap are depicted in Scenarios 13 (at a 9% interest rate) and Scenario 14 (at a 4% interest rate). The same resource assumptions are depicted assuming a 4 cents cap in Scenario 15 (at a 9% interest rate) and in Scenario 16 (at a 4% interest rate).

We find Scenarios 13-16, which incorporate an OSS price of 100% of MCP, provide the most reasonable basis among Navigant's 24 scenarios to assess the payback and maximum undercollection for purposes of the present cap evaluation. As explained below, AREM's Scenario 25, which is a variation of Navigant's Scenario 14, offers an improved forecast. Under Scenarios 13-16, Navigant computes the following years to payoff and maximum undercollection:

Summary of Results from Navigant's Scenarios 13-16

PG&E

	Scenario	Cap	Interest Rate	Maximum Undercoll.	Years to Payoff
PG&E	13	2.7	9%	223	9
	14	2.7	4%	211	8
	15	4	9%	217	4
	16	4	4%	211	4

SCE

Scenario	Cap	Interest Rate	Maximum Undercoll.	Years to Payoff
13	2.7	9%	208	6
14	2.7	4%	201	5
15	4	9%	208	4
16	4	4%	201	3

SDG&E

Scenario	Cap	Interest Rate	Maximum Undercoll.	Years to Payoff
13	2.7	9%	30.8	4
14	2.7	4%	30	3
15	4	9%	30.8	2
16	4	4%	30	2

We conclude that the most defensible forecast is one that combines the base case assumptions as to DA load levels with the remaining assumptions underlying the Navigant low case, as depicted in Navigant's Scenarios 13-16. AREM produced such a scenario, identified as "Scenario 25." AREM's Scenario 25 corresponds most closely to Navigant Scenario 14 (assuming a slightly higher 4.07% interest rate as compared to Navigant's 4% interest rate). The only substantive difference in Scenario 25 was that AREM used the base case assumptions for DA load levels, but otherwise used the low case assumptions reflected in Scenario 14. Based on the assumptions underlying AREM's Scenario 25, the following payback periods and maximum undercollections would result:

	Maximum Undercollection (in $ millions)	Years to Payoff
PG&E	$207	5
SCE	$213	4
SDG&E	$ 29	2

We conclude that Scenario 25 provides an improvement over Navigant Scenario 14. By substituting the assumed DA load level from the low case with the base in Scenario 25, the payback period for PG&E is reduced by three years and for SCE is reduced by one year compared with Scenario 14. As discussed in further detail below, although the low case presents a more reliable set of assumptions overall, we find the assumptions concerning DA load levels are more reliable under the base case. Thus, Scenario 25, incorporating the base case assumption for DA load, lends support to the conclusion that a 2.7 cents cap will provide for full payback of the undercollection by 2011. Since no party offered a defense of the high case assumptions, we find give it little to no weight in assessing likely scenarios of future DA CRS levels.

3. Determination of the 2001-2002 Undercollection

Several parties take issue with the manner in which DWR has depicted the DA CRS undercollection for the 2001-02 past periods because of the wide divergence of hypothetical values, representing a undercollection range from $431 to $822 million for the three utilities. CMTA argues, for example, that DA-in/out methodology must not produce different results for *past* periods due to uncertainty in *future* conditions. Moreover, the 2001-2002 historic undercollection represents a significant portion of the total undercollection carried forward to the entire forecast period. In 20 out of 24 scenarios run by Navigant, the undercollections accrued through 2001-02 represent the majority of the eventual maximum undercollection. In at least 10 of the Navigant scenarios, the maximum undercollection for each utility occurs in 2002 or 2003. No later than 2004, the DA customers are projected to begin paying down the maximum undercollection.

We agree that the methodology used by Navigant in computing hypothetical ranges of the 2001-2002 DA CRS undercollection fails to provide a reliable basis to determine the actual level of the undercollection. While it is necessary to forecast future events and to test the sensitivity of a range of differing scenarios, there is no logical reason why multiple hypothetical scenarios need to be devised for past periods. The assumed resource input values that may be appropriate for forecasting 2003 are not necessarily applicable to the actual recorded transactions that transpired during the 2001-2002 period. The broad variance in the range of hypothetical undercollections makes it difficult to draw meaningful conclusions concerning the resulting effects on payback period based upon the actual undercollection through the end of 2002.

In order to rectify this problem, DWR/Navigant provided a supplemental calculation of the actual undercollection attributable to DA CRS requirements for the 2001-2002 recorded period. By ALJ ruling dated May 12, 2003, this supplemental calculation was served on parties with opportunity to review and comment. DWR provide subsequent updates and corrections on May 13 and 15. Parties participated in a conference call to discuss these model updates and had the opportunity to file comments on May 19, 2003.

In its supplemental responses, DWR provided revised approximations of the recorded undercollection that did not vary based upon prospective scenario assumptions. DWR developed four alternative methods to true up the 2001-02 undercollections to actual. DWR discarded the first method because it produced illogical results.

The second and third true up methods attempt to bound the CRS undercollection. Method 2 sets off-system sales to zero, which means that all would-be direct access load that is treated as bundled for the DA-in case is met through the reduction in off-system sales and additional spot purchases, where necessary. Using Method 2, the 2001-2002 undercollection is $311 million for PG&E, $264 million for SCE, and $34 million for SDG&E. This method produces an upper bound. Method 3 maintains the off-system sales volumes as in DA-out, which means that the incremental bundled load is met entirely through spot purchases. Using Method 3, the 2001-02 under-collection is $292 million for PG&E, $255 million for SCE, and $19 million for SDG&E. This method produces the lower bound. The range between Method 2 and 3 is only $19 million for PG&E, $9 million for SCE, and $15 million for SDG&E.

The fourth true-up method generates the 2001-02 DA-in cases by applying the 2003 ratio of DA-in and DA-out off-system sales volumes to 2001 and 2002 DA-out volumes. DWR believes this methodology is more appropriate than Method 1 because it uses 2001-02 DA-out figures in the calculus, where Method 1 only applied the 2003 purchase-sales percentage to DA-in net short volumes. Using Method 4, the 2001-02 under-collection is $304 million for PG&E, $260 million for SCE, and $23 million for SDG&E.

We find that the revised range of the historical undercollection provided by Navigant offers an improvement over its initial calculations. As parties note in their comments, further scrutiny is required before final undercollection values can be determined. Nonetheless, for the limited purpose of analyzing the DA CRS cap, we find the revised DA CRS undercollection estimates to be useful.

For the limited purposes of analysis of the DA CRS cap, therefore, we shall incorporate the 2001-2002 estimated undercollection information presented in Navigant's supplemental data responses as part of the record in this proceeding. This estimated information offers a useful starting point for evaluating the DA CRS payback period and maximum undercollection under alternative caps. Thus, the assumed 2001-2002 undercollection shall be not depend upon which Navigant scenario(s) we conclude are more reliable prospectively for the period beginning with 2003. We shall then carry this estimated undercollection forward for purposes of analyzing the respective Navigant modeling scenarios starting with the year 2003 forward.

A comparison between the undercollections for 2001-2002 as reported in Scenario runs 13-16 of Navigant versus those provided in the updated response referenced above are as follows.

Comparison of 2001-2002 Undercollections in Original and Revised Scenario Runs

		Exhibit 151	**May 15, 2003 DWR Letter**		
	Scenario	Assumed Undercollection (millions)	2001-2002 Method	Estimated Undercollection (millions)	**Variance** (millions)
PG&E	13	$216	2	$311	$95
		$216	3	$292	$76
		$216	4	$304	$88
	14	$210	2	$311	$101
		$210	3	$292	$82
		$210	4	$304	$94
	15	$216	2	$311	$95
		$216	3	$292	$76
		$216	4	$304	$88
	16	$210	2	$311	$101
		$210	3	$292	$82
		$210	4	$304	$94

		Exhibit 151	May 15, 2003 DWR Letter		
	Scenario	Assumed Undercollection (millions)	2001-2002 Method	Estimated Undercollection (millions)	**Variance** (millions)
SCE	13	$208	2	$264	$56
		$208	3	$255	$47
		$208	4	$260	$52
	14	$201	2	$264	$63
		$201	3	$255	$54
		$201	4	$260	$59
	15	$208	2	$264	$56
		$208	3	$255	$47
		$208	4	$260	$52
	16	$201	2	$264	$63
		$201	3	$255	$54
		$201	4	$260	$59

		Exhibit 151	May 15, 2003 DWR Letter		
	Scenario	Assumed Undercollection (millions)	2001-2002 Method	Estimated Undercollection (millions)	**Variance** (millions)
SDG&E	13	$31	2	$34	$3
		$31	3	$19	($12)
		$31	4	$23	($8)
	14	$30	2	$34	$4
		$30	3	$19	($11)
		$30	4	$23	($7)
	15	$31	2	$34	$3
		$31	3	$19	($12)
		$31	4	$23	($8)
	16	$30	2	$34	$4
		$30	3	$19	($11)
		$30	4	$23	($7)

After taking into account the updated range of undercollections produced by Navigant in its May 15, 2003 transmittal, we still conclude that full payback of the DA CRS by 2011 is a reasonable expectation, even for PG&E which has the longest payback period. We reach this conclusion particularly in view of the forecast reflected by AREM in its "Scenario 25," as discussed above. Under Scenario 25, the payback period even for PG&E would occur significantly earlier than 2011, and in as soon as a five-year period. Thus, even considering the revised PG&E undercollection, as depicted in Navigant's updated transmittal, there is still sufficient room for the payback to conclude prior to 2011 under Scenario 25 assumptions.

Moreover, the updated undercollections presented by Navigant on May 13, 2003, do not take into account any reductions that will flow through to DA CRS obligations as a result of DWR's recently announced lowering of its 2003 DWR revenue requirement by $1 billion. In view of these factors, we conclude that the 2.7 cents cap remains sufficient for the present time to achieve pay back of accumulated DA CRS undercollections by the year 2011 for all three utilities.

4. Disposition of DWR Operating Reserves

TURN raises the question of whether a potential source of financing of the DA CRS undercollection may become available from DWR through the anticipated release of operating reserves. TURN states that reserves in the amount of $850 million were included in the DWR bond issuance in response to financial community concerns about DWR potentially being required to retain responsibility for procuring the utilities' net short requirements beyond January 1, 2003. As a result of the procurement function successfully being transferred from DWR to the utilities as of January 1, 2003, TURN expresses hope and expectation that DWR is in the process of securing approval from its lenders for the release of the $850 million of reserves. Under the Rate Agreement, the Commission, in consultation with DWR, is responsible for determining how the excess reserves will be applied.

TURN proposes that the reserves, to the extent they become available, be applied to the DA CRS undercollection that will otherwise be financed by bundled customers, rather than as a reduction in the DWR bond balance. Under the TURN proposal, DA customers would assume exclusive liability for interest payments to DWR on the portion of the DWR bonds equivalent to the reserves applied to pay down the DA CRS undercollection. If the released reserves are not sufficient to fund the entire DA CRS undercollection, TURN proposes that any remaining undercollection be repaid first before the DWR bond debt. TURN also states its preference that DWR would issue additional debt to fund the entire DA CRS undercollection.

DWR disagrees with TURN's proposal to use of any reserves that become available to pay down the DA CRS undercollection. DWR argues that bundled customers would be adversely impacted by use of the reserves to reduce the DA CRS undercollections. DWR states that any reduction in reserves normally would be used by the Commission to reduce the revenue collections currently required from bundled customers.

The actual nature, extent, and timing of any such reserves that may become available is an issue to be addressed in the context of the DWR 2003 supplemental revenue requirement review in A.00-11-038 et al. Also the specific impacts of such reserves on the modeling scenarios have not been determined as part of this proceeding, but would entail recasting the recorded undercollection as of the end of 2002. An offsetting prospective increase would be required to reflect an increase in the DWR Bond Charge obligation for DA customers and corresponding prospective reduction for bundled customers.

By paying down at least a significant portion of the DA undercollection, bundled customers would be relieved of having to finance this burden going forward, and would realize payback of any funds advanced much sooner. Because the actual determination and disposition of the reserve account is the subject of the DWR revenue requirement redetermination in A.00-11-038 et al., we do not resolve the disposition of the reserves with respect to the undercollection in this order, but defer to the A.00-11-038 et al. be considered in that proceeding.

5. Analysis of Key Variables Underlying DA CRS Cap Evaluation

We discuss below our review of the key modeling variables underlying the Navigant high, low, and base case modeling runs, and the assumptions used to develop its 24 scenarios.

a) Natural Gas Prices

The price of natural gas is a significant variable in forecasting the DA CRS requirements over time. The gas price is a direct input into the market price of electricity and is inversely related to the level of DA CRS obligation. Increases in electricity market prices, in turn, reduce the degree of stranded costs associated with fixed-price DWR contracts and correspondingly, the allocation of such costs to the DA CRS.

Navigant has used, in its Base Case scenarios, annual average gas prices ranging from $3.81 to $4.13/MMBtu at the different California trading hubs. CLECA witness Barkovich testified that these prices are "far lower" than prices available in the market, that gas prices at the border have exceeded $5/MMBtu and that forward prices for the next year have been at the same level.[10] The actual gas prices at the California border in March 2003 and recent futures gas prices for April and May 2003 were over $2/decatherm greater than

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[10] Barkovich, CLECA, Ex. 167, p. 10.

the DWR high case.[11] Beginning in March 2003, the DWR forecasts and the NYMEX futures prices begin to converge until they are comparable at a point in the middle of 2004. CMTA recommends combining the DWR low case scenario for 2003-04 with the base case for 2005-2020 to yield an improved gas price forecast. CMTA computes that such a "hybrid" scenario would result in a payback of the DA CRS obligation by 2009 for PG&E, 2006 for SCE, and 2004 for SDG&E.[12]

DWR witnesses McDonald and McMahon agreed, on cross examination, that the gas prices embedded in the Base Case are too low. McDonald acknowledged that gas price assumptions are critical to the forecast of CRS costs and that the prices in the Base Case overstate the level of the CRS and thus the undercollection under a capped CRS level.[13] Further, both McDonald and McMahon acknowledged that the DWR is considering the filing of a modified 2003 revenue requirement with the Commission and that the revised revenue requirement would include gas prices 17% to 18 % higher than those in the Base Case scenarios.[14]

This problem is addressed in the Low Case scenarios, in which the several parties participating in the Workshops agreed that Navigant should adjust the gas prices in the Base Case upward by 25%. While the gas prices in the Low Case are unlikely to be precisely correct, they better reflect current

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[11] AreM/WPTF, Ex. 181, at 16.

[12] CMTA, Ex. 172 at 5:8-3

[13] RT pp. 2054-2055, (McDonald/DWR).

[14] RT p. 2056 (McDonald/DWR); RT p. 2073 (McMahon/DWR).

conditions in the market than do the gas price forecasts in the Base Case. Navigant and virtually every other party in the proceeding appears to agree. McDonald, for example, agreed that the DWR does not regard the Base Case as the case most likely to occur.[15]

We conclude that the gas price assumptions underlying the "low" case scenario thus reflects a more realistic forecast of gas prices than that of either the base or high case scenarios. The impacts of the low case resource assumptions at a 2.7 cents cap are represented in Scenarios 14 (at a 4% interest rate) and Scenario 13 (at a 9% interest rate).

b) New Generation Capacity Additions

Navigant's ProSym cases also include assumptions regarding the addition of new generation facilities. DWR states that as part of its annual revenue requirements process, it engaged in due diligence in forecasting new generation under construction in California, the Pacific Northwest, and the remainder of the Western Electricity Coordinating Council (WECC), as well as resources that are still in the planning and permitting stages. DWR states that its forecasts closely track the January 2003 CEC forecast in most years. In its modeling runs for this phase of the proceeding, DWR reduced its forecast of new generation from that underlying its initial forecasts in support of the evidentiary record underlying D.02-11-022. Even with this downward revision, the forecast does not reflect the delay in the expected on-line date for several plants. CMTA

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[15] RT p. 2058 (McDonald / DWR).

witness McGuire testified that over 3,500 MW of new generation has been delayed beyond the dates assumed in DWR's base case.[16]

The ProSym base case new generation assumptions are overly optimistic. Overestimates of new capacity causes an overstatement of DA CRS obligations, thus exaggerating the expected payback period. CLECA witness Barkovich testified that the Navigant estimates ignore numerous generating plant cancellations and the fact that most of the companies previously prepared to develop new plants are now in serious financial trouble.[17] Barkovich believes that the amount of new generation is more likely to fall than rise and that there is a distinct possibility of an acceleration of retirements of older, more polluting plants. The Low Case adjusts the new generation entry assumptions down to 80% of those in the Base Case. We consider the low case to be a more realistic assumption for purposes of evaluating the payback period.

c) Levels of DA Load

Navigant's cases also include assumptions concerning DA load. DA load assumptions are required to calculate assumed DA CRS utilizing the DA-in / DA-out approach as adopted in D.02-11-022. For the DA-in calculation, DWR utilized DA load data provided by the utilities. For the DA-out case, DWR relied upon the December 15, 2002 DA load information submitted to the Commission by each utility. The DA-in / DA-out calculation compares the total portfolio costs based upon incremental DA load shifts between July 1, 2001 and September 20, 2001.

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[16] CMTA / McGuire, Ex. 172, pp. 7-8 (Table 1).

[17] Barkovich, CLECA, Ex. 167, p. 10.

DWR calculated DA load for 2002 using its own retail forecast and held that load constant for the Study Period. For its base case, DWR assumed no additional load shifting would occur into or out of DA. For the high and low cases, DWR assumed changes in the DA load level. Once the total dollar cost responsibility is generated by the DA-in/DA-out comparison, the resulting DA cost responsibility obligation is spread across all DA volumes that took bundled service as of February 1, 2001.

In the low ProSym case, Navigant assumed that 30% of DA load would depart simultaneously in July 2003, with subsequent DA CRS collections based on the reduced DA load. The model also subtracted a pro rata share (i.e., 30%) of the DA CRS undercollection from the balance at the time of departure. This approach effectively assumes a one-time "re-entry fee" for those DA customers returning to bundled service.

Farm Bureau argues that the assumption of a 30% decline in DA load under the low case scenario is not appropriate, and that no showing has been made as to any decline in DA load.

Overall, we agree that no convincing showing has been made to support an assumption of significant shifts in DA load, with continuation of a 2.7 cents/kWh cap. In the case of SCE, a 2.7 cents/kWh cap has been in place since July 2002 with respect to the HPC. Yet, DA load levels in the SCE territory have not declined as a result. Even those parties that support the low case scenarios do not offer a basis to support the assumption of a 30% reduction in DA load, as assumed in the low case. We conclude, therefore, that the most reasonable forecast scenario is one that applies the DA load assumptions under the base case with the other assumptions underlying the low case.

AREM, in fact, offers such a scenario. AREM supports the base case assumption for DA load, combined with the other assumptions underlying the low case. AREM has computed the effects of this combination of assumptions in its "Scenario 25," as discussed previously. In the absence of evidence to the contrary, we thus find it reasonable to assume continuation of existing levels of DA load in projecting future DA CRS payback periods.

The "Scenario 25" presented in the testimony of AREM witness McClary essentially isolates the difference attributable to the DA load assumptions between the base case and low case. AREM modified scenario essentially incorporates all of the low case assumptions for Scenario 14, except substituting the base case assumption for DA load. The substitution of the base case assumption for DA load results in an earlier payback period for all three utilities, as illustrated in Appendix 1 of Exhibit 181 (Prepared Testimony of McClary).

d) Utility Retained Generation and CTC Costs

Under the total portfolio approach, the DA CRS reflects bundled customer indifference by taking into account the total portfolio of resources including both URG and DWR sources. Thus to make a complete assessment of the DA CRS cap level, it is necessary to model both DWR and URG resources. DWR's model assumptions regarding URG and CTC are based on data provided by each of the utilities. To break down the DA CRS revenue requirement into its ongoing CTC and DWR power charge components, D.02-11-022 mandates that DA customers' responsibility for ongoing CTC be determined, and that that amount subtracted from the DA revenue requirement. The remaining amount is DA customers' responsibility for the DWR revenue requirements. The separation is necessary because different cost allocation and tariff design apply to the ongoing CTC, DWR bond charge, and DA DWR power charge rate components. Since the ongoing CTC applies to bundled as well as DA customers, one must first determine the ongoing CTC revenue requirement. One can then determine direct access customers' share.

Separate testimony was sponsored by each of the utilities sponsoring and explaining the URG and CTC assumptions they supplied to DWR for purposes of DA CRS modeling.

SCE provided Navigant three forecasts: total URG Costs, URG Energy and CTC as a unit rate. The energy and cost forecasts were based on underlying forecasts of separate components for SCE-owned URG and purchased power from Qualifying Facility (QF) contracts. The CTC was forecasted using the benchmark price adopted in D.02-011-022 measured against URG costs. SCE provided sales data based on its most recent forecast prepared in May 2001 as part of its General Rate Case

SCE URG output is assumed to be constant in all years at the 2003 level. The URG output and cost forecasts were consistent with SCE's filed Procurement Plan and with D.02-10-002. The output would reflect average generation levels, economic dispatch and average year hydro conditions. URG costs, except for the Incentive Cost Incentive Pricing (ICIP) mechanism, are escalated based on fuel specific cost factors.

The SCE QF forecast of energy and costs is tied to the underlying contracts and to the Navigant gas price forecast. This forecast also reflects fixed-price contracts that have been signed, and the gradual termination of contracts over time. SCE prepared an initial forecast through 2012, not anticipating that the projections would go well beyond this period. The forecasts after 2012 were held constant at the 2012 level

SCE's proposal incorporates the total portfolio method to calculate the uneconomic URG portion of the DA CRS, as adopted by D.02-11-022. Specifically, SCE calculates the above-market URG costs based on the total URG portfolio, as opposed to solely QF and Power Purchase Agreements ("PPA") costs, to comply with D.02-11-022, maintain consistency and to compartmentalize URG costs into a single calculation.[18]

PG&E agrees with SCE's interpretation of how to apply the total portfolio method.[19] PG&E includes in the calculation all of its pre-December 20, 1995, or "old world" generation resources, including not only its power purchase agreements but also its retained generation facilities. By contrast, Section 367[20] does not incorporate PG&E's retained generation facilities in the ongoing CTC costs it identifies. Because of the regulatory treatment adopted for these facilities, including PG&E's retained generation facilities in the calculation serves to lower the ongoing CTC revenue requirement.

Pursuant to D.02-11-022, the power component of PG&E's ongoing CTC revenue requirement is determined with reference to a benchmark of 4.3 cents per kWh adopted in D.02-11-022. The costs of PG&E's old world power costs above 4.3 cents per kWh are included in the ongoing CTC revenue requirement. Under D.02-11-022, PG&E's ongoing CTC revenue requirement also includes the net cost to meet PG&E's obligation to provide power to Western Area Power Admininstration (WAPA) under PG&E's WAPA contract.

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[18] SCE/Collette, Ex.160, pp. 4-5.

[19] PG&E/Rifas, Ex. 155, p. 1-5.

[20] All statutory references are to the Public Utilities Code.

Pursuant to D.02-11-022's direction, the cost to provide power to WAPA is deemed to be the average cost of PG&E's portfolio, including the costs of DWR power. Finally, the ongoing CTC also includes a relatively minor amount for employee transition costs.

Thus, DA CRS revenue requirement is determined so that the average costs bundled customers pays for power, including power from URG and DWR contracts, is the same as it would have been had DA been suspended on July 1, 2001, and there had been no post-July 1, 2001, DA migration.

CMTA argues that adopted CTC values should reflect the most recent determination by the Commission that is based on a substantial review of URG costs. CMTA supports the use of the URG costs for 2002 adopted for each utility in D.02-04-016. CMTA opposes PG&E's proposed CTC revenue requirement of $777,661 which is based on PG&E Advice Letter No. 2233-E which significantly updated the URG revenue requirement levels adopted in D.02-04-016. For past periods, CMTA argues that recorded URG revenue requirements and volumes should be used to estimate CTC most accurately. CMTA also argues that PG&E's CTC calculations are still not sufficiently transparent and consistent with the other utilities.

SDG&E's ongoing CTC was initially set pursuant to D.99-05-051, and made effective when SDG&E ended its AB 1890 rate freeze on July 1, 1999. SDG&E's ongoing CTC was subsequently redesigned pursuant to D.00-10-0948, effective January 1, 2001. In D.02-12-064, the Commission adopted a settlement whereby SDG&E's CTC component would continue until such time as the AB 265 balancing account has been reduced to zero and then at that time it would be revisited and adjusted in accordance with remaining tail costs.

Because SDG&E has no sunk costs remaining to be recovered pursuant to AB 1890, and because its ICIP mechanism ends this year, SDG&E believes that there no other URG costs to be addressed in the CTC component. SDG&E thus requests that its allocation and tariff design of ongoing CTC not be revisited in this DA CRS proceeding.

CMTA takes issue with SDG&E's calculation of CTC. CMTA argues that what is at issue here is whether SDG&E has any below-benchmark resources (i.e., stranded benefits) that offset to some degree its above-benchmark QF and purchased power resources. CMTA argues that SDG&E should be required to amend its CTC methodology to be consistent with that of PG&E and SCE by including below-benchmark resources in accordance with D.02-11-022.

Farm Bureau calls for a segregation of the CTC from DWR ongoing and bond costs. Farm Bureau concurs with DA parties that a review of CTC that the utilities carry forward is necessary. Farm Bureau also argues that segregation of CTC from the DWR costs is the only logical way that Draft Resolution E-3813 (for utilities' filed tariffs regarding DA CRS) can be implemented. The Draft Resolution would require charging continuous DA customers and DA customers charged under the CRS cap the same ongoing CTC until the full revenue requirement is recovered from DA customers. Farm Bureau argues that any other mechanism could possibly lead to limited or no recovery of CTC from continuous DA customers.

Farm Bureau opposes PG&E's request to utilize this proceeding to affirm a recalculation of its CTC. By making CTC charges consistent with other charges borne for utility costs to serve any load, Farm Bureau argues, a better balance will be struck between DA and bundled customers. Furthermore, the segregation of CTC will comport with the movement to bottoms-up billing.

As stated previously, this phase is not the designated place for adopting and finalizing CTC components for DA CRS purposes. In Section IV, we discussed the planned process for finalizing CTC values. The CTC values that have been presented in this phase are relevant for purposes of modeling the forecast DA CRS under the total portfolio approach which requires assumptions concerning CTC. Parties have raised various issues concerning the appropriate level of CTC for each of the utilities, particularly for PG&E. We need not resolve all of those CTC issues here. As noted by AREM, differing forecasts of CTC URG components do not appear to have a substantial impact on forecasting the impact of the cap. We also note that the CTC methodology used by SDG&E is not consistent with the total portfolio methodology in that it does not include URG resources that are below the CTC benchmark cost. The fact that SDG&E has ended its rate freeze does not relieve it from including all of its URG to achieve a total portfolio indifference value for its DA CRS. In finalizing the DA CRS total portfolio indifference calculation for SDG&E, we shall require that SDG&E conform to the total portfolio approach consistent with D.02-11-022.

e) Off-System Sales (OSS) Prices

DWR/Navigant's ProSym cases model two alternative assumptions as to the sales price of excess DWR power. The scenarios assume power will be sold at either 50% or 100% of the indicated hourly market prices from PROSYM. The assumed 50% sales price lowers the estimated revenue received for the sale of surplus power and thereby increases estimated CRS costs. DWR's estimate of the price received for such power is a key variable in determining CRS costs. Since the utilities are now responsible for dispatch of the DWR power, DWR's assumption would now impose this very low assumed price for sales of excess power to their activity in the year 2003 and beyond.

While the DWR's experience in 2001 and early in 2002 may have been consistent with a 50% assumption, changes in its sales practices in 2002 resulted in substantial improvement in the prices as of the time of the hearings last summer.[21] Further, the Commission found in D.02-11-022 that a more reasonable assumption, based on evidence then before the Commission, would be closer to 100% than 50%.[22]

DWR states that the 50% assumption is based on its experience in 2001 and that it has asked the utilities to provide a new estimate based on their sales experience after January 1, 2003.[23] McDonald testified that the 50% assumption is included in the CRS scenarios because it was used in the DWR 2003 revenue requirement, which was prepared in the spring and summer of 2002.[24] PG&E witness Burns, while agreeing that DWR's 2003 revenue requirement is too high, testified that the 50% OSS assumption embedded in that revenue requirement is appropriate for use in calculating the CRS estimates here as a matter of consistency.[25]

SCE witness Collette testified that SCE's experience in the first two months of 2003 with sales of DWR power shows that it achieved prices equal to 96% of the average purchase price.[26] As discussed in the hearings leading to

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[21] Ex. 167, p. 9.

[22] D.02-11-022, p. 77 (slip op.).

[23] DWR, Ex. 150, p. 7.

[24] RT p. 2046 (McDonald / DWR).

[25] RT pp. 2138-2140 (Burns / PG&E).

[26] Collette, Edison, Ex. 160, p. 10.

D.02-11-022, the average purchase price will tend to be higher than the average sales price simply because of the load conditions under which each is most likely to occur. Thus, achieving sales prices equal to 96% of purchase prices is likely to reflect sales prices at levels in excess of PROSYM market clearing prices for the hours in which the sales were actually made. Collete testified that an 100% OSS assumption is the only reasonable assumption for purposes of long-term evaluation of the CRS.[27]

We find the 50% OSS assumption to be highly unlikely as a basis for estimating prospective CRS requirements for evaluating the duration of the CRS shortfall at various cap levels. The only party to support a 50% OSS assumption was PG&E. The only rationale offered by PG&E for the 50% assumption, however, was consistency with the DWR's 2002 revenue requirement determination. Yet PG&E witness Burns testified that there is no basis to assume a 50% assumption is more accurate than an OSS valued at 100% of MCP. PG&E conducted no analysis to compare the prices it obtained from OSS with the prices assumed by DWR's ProSym model.[28] TURN recommended an OSS price range of "about 75% to 90 %" of MCP. Farm Bureau believes a midpoint compromise of 75% MCP assumption reasonably recognizes the uncertainty of predicting the actual level. ORA offered no position on this issue.

We conclude that those scenarios incorporating an assumption of OSS valued at 100% of MCP provide the most reliable model runs for purposes of evaluating the appropriate DA CRS cap. We do not believe a model run

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[27] RT p. 2228.

[28] RT pp. 2136-2137 (PG&E/Burns).

assuming a 75% MCP level provides a more reliable basis for evaluation. A 75% MCP assumption would imply that both the 50% and 100% MCP levels have an equal likelihood of occurring. Yet, such an assumption would be wrong since we have found little empirical basis to support the 50% level going forward. Since the utilities have resumed responsibility for procurement going forward, the dysfunctional market conditions that led to more discounted OSS price levels should no longer be impacting market prices. We are persuaded by the testimony of SCE witness Colette that a 100% OSS assumption is the only reasonable assumption for long term evaluation purposes.

6. Interest Rate Assumed as a Source of Financing

In order to remain indifferent with respect to DA migration, bundled customers must be compensated for the time value of money associated with funds advanced to cover DA CRS undercollections. In D.02-11-022, we directed that interest rate applicable to the DWR Bond Charge be applied on an interim basis for the financing the cap through July 1, 2003. We directed that further inquiry be conducted regarding longer term arrangements for the costs of financing of the DA caps.

For purposes of the scenarios modeled by Navigant, two alternative interest rate assumptions were used, one at 4% and a second at 9%, incorporating the range of interest rates requested by parties pursuant to the modeling workshop. The difference in interest rates causes a one-year difference in payback period. The longest payback period is projected for PG&E (between eight and nine years). The impacts of the low case resource assumptions at a 4 cents cap are represented in Scenarios 16 (at a 4% interest rate) and Scenario 15 (at a 9% interest rate). The difference in interest rates results in a one-year difference for SCE and no difference in payback period for PG&E or SDG&E.

a) Parties' Positions

A variety of proposals are offered as to the appropriate interest rate to be applied to compensate bundled customers for the carrying costs of funds advanced to cover DA CRS shortfalls.

ORA and TURN both proposed that the interest rate be indexed to the utility rate of return on rate base. ORA sponsors an after-tax approach while TURN favors a pre-tax approach. TURN believes the pre-tax utility rate of return, currently in the 12%-13% range, is analogous to the long-term nature of the bundled customers' "loan" to cover the DA CRS obligation. The utility rate of return provides a return on assets with a relatively long life.

ORA proposes the utility's rate of return (net of taxes) be used to compensate bundled customers for funding the DA CRS undercollection. So that direct access customers in the three utility service areas are treated the same, ORA proposes a simple average of the authorized returns of the three utilities be used.[29] ORA proposes a 9.25% interest rate (equivalent to the average after-tax cost of capital for all three utilities) be applied where the adopted cap is 3 cents/kWh or less, and an interest rate of 8.25% apply if a 4 cents/kWh cap is adopted (as proposed for PG&E). The 100 basis point differential is intended to reflect the reduced risk of a shorter payback period.

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[29] Currently, the simple average authorized cost of capital is 9.25%. Pursuant to D.02-11-027, the authorized costs of capital of the three utilities are 9.24% (PG&E), 9.75% (SCE), and 8.77% (SDG&E).

ORA derives the 100 basis point differential based on a comparison of risk differentials reflected in the cost of capital using SCE as an example. The difference between SCE's weighted average cost of capital (9.75%) and its corporate bond rate (8.19%) is 156 basis points. (ORA Ex. 162, footnote 6; Edison Ex. 160, p. 11.) ORA notes the difference between SCE's weighted average cost of capital (9.75%) and its corporate bond rate (8.19%) is 156 basis points. (ORA Ex. 162, footnote 6; Edison Ex. 160, p. 11.) Corporate bonds are instruments are fully secured instruments, whereas the weighted average cost of capital represents a mix of instruments with only limited security. Rather than apply a full 156 basis point reduction to interest rate charged to core DA customers, ORA believes a two-thirds reduction (100 basis points) is appropriate since the risk remains unsecured regardless of how it is allocated.

ORA identifies three major components of risk: (a) loan duration, (b) source of borrower, and (c) lack of collateral security. ORA characterizes the DA CRS loan term as unusually long compared with the short-term nature of debt typically financed by commercial paper. The precise duration is also of unknown duration. Risk typically increases as a function of longer duration. ORA also proposes that the interest rate adopted reflect the duration of the CRS undercollection.

ORA notes that unlike most customer loans that are made to the utility, this loan is made to another class of customer. Thus ORA views the risk of repayment as being tied more to the creditworthiness of the DA customer than that of the utility. ORA proposes that the Commission should adopt an explicit policy requiring the remaining DA customers to bear the debt owed by DA customers who become insolvent or move out of state and thus are unable or unwilling to pay the debt themselves. ORA proposed an accounting system to ensure that DA customers pay their share of the debt.[30] ORA's proposed accounting system is discussed in more detail below.

Moreover, unlike a voluntary loan between two private parties, ORA also distinguishes the nature of this loan as being involuntary. As the closest analogous situation, ORA draws upon the example of a Commission-approved energy conservation program where the initial capital investment in conservation technology is funded by nonparticipating utility customers. The investment is paid back in future years in the form of energy savings and avoided generation costs. ORA notes that most recently, parties have settled on using a discount rate of 8.15% to measure the present value of costs and benefits that reflect both participants and nonparticipants viewpoints.[31]

ORA argues that the risk of this loan is increased by virtue of lacking collateral in the form of secured assets such as would be true of a secured bond. ORA also expresses concern that the only security offered is through the Commission's ratemaking authority which could be subject to change before bundled customers are fully paid off.

Farm Bureau proposes an alternative approach using two different interest rates, separately applied to residential and business customers to reflect each group of customers' different costs of money. For its analysis, Farm Bureau used a 10-year average of the "Weighted Average Consumer Rate" (at 12%) for residential, and the "Average Long Term Corporate Bond Rate" (at 7.6%) for all other customers. The Weighted Average Consumer Rate is based

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[30] See ORA Ex. 162, Attach. A.

[31] ORA cites to the ALJ ruling of October 25, 2000 in A.99-09-049.

upon an index produced by the Federal Reserve Bank of New York, and includes financing sources such as credit card debt. The corporate bond rate reflects the cost of money to companies with a wide range of credit worthiness levels.

The weighted average consumer rate provided by the Federal Reserve Bank of New York includes financing sources such as credit card debt, which is a source of financing that is more widely available to residential consumers. Farm Bureau believes that this latter rate would be a more appropriate for balances owed to residential customers. Farm Bureau also argues that the average long-term corporate bond rate is more reflective of the type of longer-term loans available to businesses.

Under the Farm Bureau's approach, different repayment balances would have to be maintained for residential and other customers so the differing interest rates could be applied to their respective undercollection balances.

SCE proposed the use of the interest rate associated with utility long-term debt. In its initial testimony, SCE proposed to apply its after-tax cost of long term debt as the interest rate on DA CRS undercollections. Based on its adopted cost of long-term debt of 8.19%,[32] SCE proposed to apply an after-tax cost of debt of 4.87%. This rate is close to the 4.89% interest rate on DWR bonds, which was prescribed as the source of interim financing for the DA CRS undercollection in D.02-11-022. Subsequently, SCE revised its position to propose use of the 8.19% before-tax interest rate.

SDG&E and various other parties representing DA interests propose the use of the three-month commercial paper interest rate that is

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[32] See D.02-11-074

generally applied to finance utility balancing accounts. The general utility practice is to finance balancing accounts at a monthly rate equal to one-twelfth of the three-month commercial paper interest rate for the previous month, as reported in the Federal Reserve Statistical Release, G.13, or its successor. SDG&E argues that the DA CRS "risk" is no different from that associated with other utility balancing accounts. SDG&E cites as an example, the Assembly Bill (AB) 265 undercollection which rose to approximately $750 million. Yet, the Commission still only applied the three-month commercial paper rate.[33]

AREM provided a tabulation of the three-month commercial paper rates from March 1999 through February 2003, indicating an average of 4.07% during this period, with swings between 1.25% and 6.59% AREM proposes that the 4.07% average be assumed as the interest rate on undercollections on a going forward basis, and that the actual three-month commercial paper interest rates be applied to actual balances through December 2002. AREM considers this to be a conservative assumption since near term interest rates are likely to be below the 4.07% average.

CLECA argues that a 4% interest rate for purposes of financing the CRS undercollection appropriately reflects the nature and risk of the loan at issue. CLECA characterizes the CRS loan as having a relatively high degree of assurance of repayment, backed by the Commission's determination to assure full repayment. CLECA witness Barkovich testified that the only repayment uncertainty is the possibility that DA customers go out of business before the undercollection is paid off. CLECA opposes the use of the utility cost of capital

[33] RT p. 2300 (Hansen / SDG&E).

as an interest rate measure because the utility is not doing the financing, but the customer is. CLECA contends that the customer's alternative lending opportunities are based on interest rates that banks pay to consumers.

CMTA proposes that for purposes of financing the initial CRS undercollection covering the period September 20, 2001 through December 31, 2002, the three-month commercial paper rate valued at 1.77% should apply. For subsequent financing from January 1, 2003 forward, CMTA proposes use of the DWR bond rate which it represents as 4.74%.

Corona characterizes the CRS advances by bundled customers as a "reallocation of costs" among customer groups rather than a "loan." As such, Corona argues that any interest rates applied in such situations traditionally are assessed interest at no more than the commercial paper rate, if any interest rate is applied at all. Corona argues that the interest rate proposed by TURN would be usurious and cause a windfall to bundled customers in violation of the Commission's goal of customer indifference.

b) Discussion

To preserve bundled customer indifference, the interest rate adopted for the DA CRS undercollections must compensate bundled customers for the time value of money. By funding DA CRS undercollections, bundled customers give up the use of funds that otherwise could be used to invest, pay off debt, or spend for current goods and services.

As a proxy for bundled customers' time value of money, various parties referenced the cost of money of the utility. There are limitations in the use of such a proxy. Utility financing involves only a single entity going to the capital markets for specific financing needs. Bundled customers, however, represent divergent classes and individuals within those classes with differing costs of money. For example, business customers typically may deduct their interest costs for income tax purposes, thereby lowering their after-tax cost of money. Residential customers, however, may be unable to claim a tax deduction for interest expense. Thus, aside from any other differences, the after-tax cost of money differs for various customers depending on whether deductibility of interest for income tax purposes.

Residential customers may also experience different costs of money among themselves associated with providing financing of the DA CRS undercollection depending whether they are a net borrowers or net lenders for their source of funds. For example, net borrowers that incrementally draw from an 18% interest-bearing line of revolving consumer credit have a very different marginal discount rate from customers that are net leaders that incrementally draw upon money market investment funds earning perhaps as low as 1%-2%. We thus cannot identify a single interest rate that will precisely track every bundled customer's cost of money to compensate for financing the DA CRS undercollection. Instead, the best approximation of bundled customers' cost of money indicator comes from examining the characteristics of the DA CRS undercollection, itself.

The DA CRS undercollection represents a debt obligation with a duration of multiple years. As such, the relevant standard for identifying the cost of money is the risk and return characteristics associated with a debt instrument. Thus, returns associated with equity investment securities do not inform us as to relevant measures of debt return and risk, such as we are considering here. The rate of return adopted for an investor-owned utility includes separate elements to compensate different types of investment risk. There is a both a long-term debt and a stockholder's equity component for which a cost of capital is determined based upon the risk and return characteristics of the each type of investment.

Applying the utility authorized return on rate base as a proxy for the interest rate applicable to the DA CRS undercollection implies that the cost of money for bundled customers is a mixture of utility long-term debt interest expense and utility common equity profits in proportion to the amounts reflected in the authorized utility rate of return. Yet, no basis has been laid to show that the composite risk / return elements authorized to compensate investors in utility bonds and common stock somehow mirror the risk-adjusted cost of money experienced by bundled customers in connection with financing debt in the form of the DA CRS undercollection.

While we agree that the debt component on the utility rate of return at least bears some similarity to the DA CRS undercollection in that both reflect a fixed obligation to be repaid over a period of years, we find no similar analogy with respect to the equity component of the utility rate of return.

Utility stockholder's risk and return is distinguishable from the risk and return characteristics of debt holders. Debt holders' downside risk is limited to default of a fixed amount to the extent that the utility rate of return on rate base incorporates a stockholders' equity component, ORA and TURN have failed to show how risk and the risk and return characteristics of utility equity investors reveals the relevant risk-adjusted cost of money associated with bundled customers' financing of debt.

We thus conclude that the more relevant benchmark for evaluating an appropriate the interest rate proxy on the DA CRS undercollection is debt rather than stockholders' equity. The risk associated with debt is, in part, a function of the length of time until payment in full with interest. In this instance, the DA CRS debt is being financed over multiple years. Thus, an appropriate matching of the customer's cost of money can be achieved by referencing a debt proxy with a longer-term maturity. SDG&E argues that a three-month commercial paper rate is the correct proxy since it has been used to finance balancing accounts over periods of equal or greater length to that of the DA CRS.

We do not find the three-month commercial paper rate to be necessarily analogous to the cost of money experienced by bundled customers in the context of DA CRS. Unlike balancing accounts where undercollections are financed by the utility, the undercollection of the DA CRS is financed by a class of customers. The three-month commercial paper rate may be appropriate for certain balancing accounts where the utility is doing the financing through short-term commercial paper markets. Because the financing of the DA CRS undercollections is between two classes of customers, however, rather than the utility, the relevant measure is the cost of money experienced by the bundled customer. The risk-adjusted cost of money associated with one group of ratepayers being required to loan money to a second group of customers is not defined necessarily by the rate at which a utility may borrow to finance its own undercollections. Parties have identified various risk factors associated with bundled customers advancing funds DA customers to cover the DA CRS over a period of years. Thus, we conclude that a debt proxy with a three-month duration does not reflect bundled customers' risk-adjusted cost of financing over a period of years. Even though the duration of the SDG&E undercollection is expected to be shorter than that for PG&E and SCE, the expected term is still longer than the term of three-month commercial paper.

Certain parties point to the as examples of balancing accounts such as the TCBA and PROACT with multi-year lives that accrue interest at the three-month commercial paper rate. Such accounts are not analogous to the DA CRS undercollection that extends for a longer period for least for PG&E and SCE. The repayment period for SCE's PROACT undercollection was limited to four years, and the actual repayment period is now expected to be only about two years. In the case of the TCBA, a short-term interest rate was applied with the expectation that the residually determined headroom revenues would fluctuate between positive and negative balances on a month-to-month basis. The DA CRS undercollection, however, is not expected to fluctuate between positive and negative balances on a short-term basis in this manner, but rather will be amortized over a period of years.

Debt holders typically demand higher interest rates for agreeing to lend money for longer periods. The risk associated with a longer duration is a function both of default risk and interest rate risk. That is, by tying up money for longer periods, the debt holder gives up the flexibility to adjust to changes in market interest rates that may occur during the term of the long-term debt.

Two measures of long-term debt were offered into the record. SCE offered its own utility long-term debt of 8.1%. No comparable figures were offered for PG&E or SDG&E. Farm Bureau offered a broader economy-wide measure of corporate long term of 7.1% for 2002 and 7.6% as a 10-year average based upon statistics from Moody's Investment Services Corp.

We conclude that the long-term corporate debt figures offered by Farm Bureau provides the most useful proxy for applying an interest rate on the DA CRS undercollection. The corporate debt figures represent a much broader economic spectrum than the single SCE interest figure, and as such, are more representative of the cost of money applicable to a broad spectrum of bundled customers. To the extent it represents a broad spectrum of borrowers, the corporate rate offered by Farm Bureau would reflect some averaging of risk premium for general default risk. For purposes of assessing the projected DA CRS payback period, the 10-year average interest rate of 7.6 % presented by Farm Bureau is a relevant measure since it measures a period roughly covering the projected period until pay back of the DA CRS undercollection.

For purposes of setting an actual interest rate to apply for the current period, however, the 7.1% average corporate interest rate computed for 2002 is more appropriate since it represents more contemporary data. Accordingly, we shall authorize an interest rate of 7.1% for purposes of accruing interest on the DA CRS undercollection, continuing in effect until the next DA CRS revenue requirement redetermination. The applicable interest rate amount shall be updated concurrently with the next DA CRS revenue requirement update to reflect more recent data concerning average corporate interest rates.

Certain parties (e.g., ORA and TURN) have argued that the default risk associated with DA CRS undercollections should be compensated at a rate higher than corporate interest rates on long-term debt. We find no basis, however, to quantify any further interest rate premium related to the default risk associated with repayment of the DA CRS undercollection. For similar reasons, we decline to adopt a figure as high as 12% interest figure as proposed by Farm Bureau applicable to residential customers.

ORA and TURN identify potential risks that repayment that the term of payoff will take longer than expected, or that individual DA customers will either go bankrupt or relocate outside of California, thereby defaulting on their repayment obligation. We have addressed these risks through the design of the DA CRS mechanism. To the extent that the forecasted payoff term varies from actual results, we have provided for periodic reevaluation of the cap so that adjustments can be made to assure timely repayment.

Moreover, we have designed the DA CRS methodology such that the repayment is a liability of the entire class of DA customers who took bundled service after February 1, 2001. Thus, even if individual DA customers possibly default on their share of the DA CRS repayment, their share shall be reallocated back into the total pool of DA CRS obligations in the periodic cap redeterminations. We are also adopting the accounting and tracking recommendations of ORA to ensure that DA cost responsibility is properly assigned to the respective customer group. Because the DA CRS cap and progress toward repayment shall be reviewed on an ongoing periodic basis, the per-kWh obligation assigned to the remaining pool of DA customers will be adjusted, as necessary, to absorb any increase in the undercollection attributable to defaulting DA customers.

Likewise, repayment of the DA undercollection will not be jeopardized to the extent that DA customers return permanently to DA bundled service since we have required that such customers shall still remain liable for paying their applicable share of the DA CRS undercollection. Moreover, DA customers returning to bundled service will continue to pay the applicable DWR Bond Charge and tail CTC as part of bundled charges.

Certain parties claim that bundled customers are at risk for DA CRS repayment as a result of the chance that a future body of commissioners may change existing commitments and reduce or cancel DA CRS repayment obligations. Changes in a Commission order, however, require due process with opportunity for interested parties to be heard. We find no reasonable basis to speculate that a future Commission order might reverse or nullify the commitments and obligations that are now in place requiring timely reimbursement to bundled customers of DA CRS undercollections.

We further conclude that the interest rate should be accrued on an pre-tax basis to residential customers and on an after-tax basis to other customers. Because interest is generally tax deductible for business customers. Thus, an after-tax interest rate is appropriate for accrual of interest on their share of DA undercollections. Likewise, because residential customers typically cannot deduct interest. A pre-tax interest rate is appropriate to compensate them for their share of undercollection.

We conclude that the accrual of interest on an after-tax basis to bundled nonresidential customers is appropriate to avoid overcompensating them for their actual cost of money. Since proceeds from the cap fund currently fund only a fraction of the DA CRS obligation, interest incurred to finance the undercollection will not be reimbursed to bundled customers in the initial years. Interest will merely be accrued for accounting purposes as an additional obligation to be reimbursed to bundled customers in future years. Thus bundled customers will incur interest expense to finance the DA CRS undercollection, but will not receive offsetting interest reimbursement from DA customers until future years. For business customers, interest expense is typically deductible as a cost of doing business for income tax purposes. Thus, their cost of money will be reduced to the extent of the tax deductibility of interest charges.

If interest were accrued on the DA CRS undercollection at a pre-tax interest rate, it would cause DA customers to fund interest payments associated with the deferred tax benefit related to this interest deduction, at least for business customers. A pre-tax accrual would create a mismatch between the costs of money incurred and the obligation assessed against DA customers. Bundled customers would realize a reduction as result of deducting the interest charges, and yet would also receive compounded interest on the undercollection, compounded at a pre-tax interest rate as if no tax deferral had been realized.

To prevent overcompensation to bundled customers subject to tax-deductible interest, it is thus appropriate to accrue interest on their share of the undercollection using an after-tax interest rate. In this manner, the DA CRS obligation associated with interest rate financing will properly track the actual tax-adjusted interest costs incurred by such bundled customers.

For purposes of computing an after-tax rate, the marginal utility income tax rate is a reasonable proxy. SCE, in its proposal, utilized a ratio of 59.46% to derive an after-tax rate in its initial proposal for applying an after-tax interest rate. SCE initially proposed an after-tax interest rate of 4.87% equal to 59.46% of its pre-tax interest rate of 8.19%. While the specific marginal tax rate of individual customers will differ, the utility tax rate provides a practical approximation for our purposes. Accordingly, we shall apply an after-tax ratio of 59.46% to the corporate interest rate of 7.1% proposed by Farm Bureau to derive an after-tax rate of 4.22%.

We disagree with SCE and TURN, who claim that the DA CRS interest rate should be applied on a before-tax basis for all bundled customers based on the fact that a utility recovers interest charges from its own customers on a before-tax basis. Bundled business customers, however, do not collect offsetting taxable revenues to compensate for their interest expense in the same tax year as does the utility. Thus, it is appropriate to apply an after-tax interest rate for the DA CRS undercollection applicable to bundled "non-core" customers.

7. Avoiding Making DA Uneconomic to Customers

As stated above, one of the criteria underlying the DA CRS cap is to seek to avoid making DA uneconomic to customers thus threatening its continuation. In prior decisions, we have determined that it is in the public interest for DA to continue. For example, we stated in D.02-03-055:

> "AREM and others contend that an earlier suspension will negatively affect California businesses, and thus, affect the California economy. With increased electricity costs resulting from an earlier suspension, California's economy may suffer if firms relocate or choose not to enter the state. ... . [S]uch increased costs also affect important state functions, such as the delivery of quality education. . .. Further, ORA states "direct access is a means of diversifying the California electric power market, and therefore helps to protect California against uncertainty." Moreover CMTA/CLECA notes that the growth of direct access load in summer 2001 contributed substantially to a $2.6 billion reduction in the level of the DWR revenue requirement estimate for the period through December 31, 2002. We agree . . . that there are significant risks associated with an earlier suspension date as well as benefits associated with retaining a viable direct access market."

Accordingly, in the interests of maintaining the benefits to the public interest that DA offers in terms of jobs, enhanced tax base, and energy diversification, we seek to maintain a DA CRS cap level that avoids making DA uneconomic, threatening the continuation of DA.

a) Parties' Positions

Parties are in dispute concerning to what extent increases in the existing cap can be tolerated without causing harm to DA. Although various parties representing DA interests complain as to the financial difficulties of absorbing even the existing 2.7 cents cap, no party argued that any reduction in the cap below 2.7 cents was required to maintain the continuation of DA.

Parties raise a number of considerations in assessing the relationship between the level of any DA CRS cap and the continuing economic survival of DA. At one level, the question is whether the alternative to DA viability is a return to utility bundled service. At another level, the loss of DA may be expressed through businesses relocating outside the State of California, or simply business contraction (in the extreme, going out of business).

CLECA witness Barkovich testified that some companies are considering moving to neighboring states so that they can still service their California customers. For industrial customers that are significant users of electricity, especially in a recession, the cost of power is a critical issue. If power prices rise high enough, some businesses have alternatives to operation in California. Manufacturing customers competing with imports can import partially or fully manufactured products rather than produce them in California, and California manufacturing jobs will be lost.

DA parties argue that the Commission should take into consideration the impact of any increase in the CRS cap on the ability of direct access customers to remain competitive in their industries. CLECA witness Barkovich testified that an increase to 4 cents would, when added to generation procurement costs and transmission, distribution and other related utility costs, render the direct access service uneconomic relative to bundled service.[34]

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[34] Barkovich, CLECA, Ex. 167, at pp. 13-17. The 4 cent figure was used by DWR in its scenario analysis.

The risk of losing DA load to bundled service is particularly pronounced in the case of SCE, which has applied for and anticipates substantial bundled service reductions in customer bills on or about July 1, 2003. ORA states that its support for an increase in the SCE cap to no more than 3 cents for SCE in view of this proposed reduction in A.03-01-019. ORA believes that an increase up to 3 cents for SCE now will prevent the problem of DA viability from becoming worse later on. ORA questions the contention that an increase in the cap from 2.7cents to 3 cents will cause DA customers to go out of business en masse. SCE likewise argues that DA appears to remain vigorous under the 2.7¢/kWh cap based on current DA load statistics and recent requests by DA customers to add load to DA accounts and to maintain DA status for relocated accounts.[35]

ORA's Exhibit 163, Attachment B, shows that at generation procurement prices above 5 cents, there is little room for any increase in the cap and that following the anticipated SCE reduction in customer bills, the cap room for TOU-8-Sub customers falls to less than 1 cent. This means that direct access will then be more costly than bundled service even at the current 2.7 cent cap. ORA's cross-examination of PG&E witness Rifas offers the prospect that PG&E's bundled service rates may also be falling in the not-too-distant future,[36] thereby creating the same issue on PG&E's system.

SCE argues that a cap raised to 3 cents would not make DA uneconomic. SCE notes that while CLECA favors the 2.7 ¢/kWh cap, it

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[35] SCE/Collette, Ex. 160, pp. 6-8.

[36] RT pp. 2114-2117 (Rifas/PG&E); Exs. 157 and 158.

ultimately recommended "that the cap stay in the range of 2.5 to 3 cent per kWh."[37] CLECA made this recommendation with knowledge of SCE's post-PROACT reduction recommended in A.03-01-019.[38] Similarly, although CMTA's "primary recommendation is to maintain the 2.7 c/kWh cap," its witness conceded that "if the Commission decides that the cap should be increased, CMTA recommends that the cap not exceed 3.0 c/kWh."[39]

None of the parties representing DA interests provided concrete data regarding the current prices that they are paying for power to allow the Commission to "quantify the precise relationship between the level of a cap and the number of DA contracts that may become uneconomic," which was the stated aim of D. 02-11-022.[40] Testimony presented as to the economic impacts of the DA CRS cap was anecdotal in nature, but did not provide broad or comprehensive statistics on the overall effect on the DA program. A more comprehensive empirical evaluation of the effects of various cap levels on DA economic survival is impeded by the lack of specific information on the energy prices DA customers currently pay their ESPs. DA customers remain unwilling to disclose contractual pricing information that could potentially be used by competitors.

Strategic Energy, for example, presented evidence on how the DA CRS will increase the energy costs of DA customers. As an example of the

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[37] CLECA/Barkovich, Ex. 167, p. 26.

[38] CLECA/Barkovich, Ex. 168, p. 6.

[39] CMTA/McGuire, Ex. 173, p. 9.

[40] D.02-11-022, p. 108 (slip op.); RT pp. 2370-2371 (CMTA/McGuire).

effects for a large retail customer, Target Corporation estimates that the 2.7 cents cap will translate into about $11 million per year, or $40,000 per store annually. Testimony was also presented on the effects of the DA CRS on the California's higher education system which is a DA customer.

In addition to business customers, DA is also utilized by public institutions, such as the UC/CSU system and municipalities such as Corona. For such institutions, the viability of DA affects not only employment levels but also arguably the quality of educational opportunities and quality of municipal services. UC/CSU alleged that increases in the DA CRS cap could cause colleges to cut back on services to students. UC/CSU states that an increase in the cap to 3 cents would require colleges to deny class access to 315 students. UC/CSU thus does not focus its analysis on the question of whether cap increases could render the DA option no longer viable as an economic option. Rather, their focus seems to imply increases in the cap would not cause UC/CSU campuses to discontinue DA, but would rather cause them to cut other university programs and services to offset cost increases in DA.

PG&E does not address how increasing the currently adopted 2.7 cent DA CRS cap to 4 cents per kWh would affect DA economic viability or whether it would force direct access customers to shut down or relocate their operations. PG&E believes that while raising customer charges is an important concern, it is important for bundled as well as DA customers. PG&E argues that even with a 4 cent cap, DA is competitive with bundled service, assuming DA power prices at about 5 cents/kWh. PG&E thus believes that a better basis for setting a cap is to limit the period of time during which DA customers lean on bundled customers, rather than lower direct access customers' charges now at the expense of a longer payback period for the loan from bundled to direct access customers.

TURN and Farm Bureau argue that raising the DA CRS cap to as high as 4 cents/kWh would not impair the economic viability of DA. TURN argues that there is no evidence that a low cap would be better for the state's economy than a high cap, or no cap at all on DA CRS. TURN argues that the cap does not eliminate overall system costs, but merely shifts those costs from DA customers to bundled customers. TURN argues that whatever adverse economic effects may result from the imposition of DWR costs on DA customers, the same potential risks face bundled customers to the extent they must shoulder those costs. Because the cap simply defers, but does not eliminate, the DA CRS payment obligation, TURN argues that a low cap does not promote any greater economic development than a high cap or no cap.

TURN also argues that the correct analytical approach to evaluating DA economic viability resulting from any cap should focus only on the avoidable costs facing DA customers if they return to bundled service. Because the DA customer cannot avoid the DWR bond charge, other past DWR shortfalls, the HPC, or CTC by returning to bundled service, TURN argues that these elements are not relevant for assessing the economic consequences of a DA CRS cap. TURN contends that the only relevant comparison for purposes of determining a cap is between (1) ESP charges plus DWR power charges versus (2) the bundled generation rate plus any allocated shortfall resulting from a DA CRS cap.

PG&E proposes raising its cap as high as 4 cents/kWh. ORA believes that PG&E can support a 4-cent cap, at least in the near term, without causing DA contracts to become uneconomic to a significant degree. PG&E is still under frozen bundled rates that include high surcharges. ORA argues that the reduction in the current DA credit resulting from a 4-cent cap would still leave DA contracts that are at current market rates less expensive than bundled rates. (ORA Ex. 163, Attach. B.) ORA thus advocates raising PG&E's CRS cap to 4 cents for a short while, with the aim of paying off the CRS undercollection faster. When PG&E's surcharges are terminated, ORA agrees that reducing PG&E's CRS to something closer to SCE's proposed 3 cent cap could be considered.

While not disputing that a higher DA CRS cap might impact the businesses of current DA customers, SCE argues that bundled service customers face the same hardships caused by a sluggish economy as DA customers state they are experiencing. A lower DA CRS cap, lower interest rate and longer repayment period for DA customers translates into a longer period that bundled service customers must pay higher electric charges.

b) Discussion

In evaluating the potential adverse harm, we recognize that there is no single level of a cap at which DA will become uneconomic for all DA customers. There are wide variations in the business needs and opportunities facing various DA customers, and the effects of any particular cap will affect each DA customer differently. Even at the existing 2.7 cents/kWh cap, some DA customers may be unable to remain viable. Moreover, it is difficult isolate the effects of the DA CRS from other economy-wide influences that may impact a DA customer's continuing survival. Because of the divergence of DA customer characteristics and the lack of specific data concerning the actual prices paid under DA contracts, we can only make generalized observations concerning the level of cap.

Another criterion is to focus on a comparison between the costs of DA versus bundled service. The DA customer would still remain responsible for paying down any previously accumulated DA CRS undercollection as a condition of returning to bundled service. Certain parties noted that DA viability is impacted based upon current comparisons of bundled versus DA costs, but also with respect to future directions that bundled versus DA service costs may take.

TURN is correct that the elements covered under the cap include some that would apply under either the DA or bundled service option. In our assessment of DA economic viability we take into account the fact that the alternative charges the DA customer would face under the bundled service option would continue to include those same elements. By consistent comparisons of bundled and DA service options that both include the unavoidable surcharge elements, we properly focus on the residual differences between the bundled and DA options that comprise the avoidable cost elements. By subtracting the unavoidable DA CRS cost elements from 2.7 cents, we can derive an equivalent implicit cap level that applies solely to the 2.7 cents/kWh surcharge. The fact remains that it is the cumulative burden of the avoidable and unavoidable elements that drives discretionary economic choices at the margin. While the avoidable surcharge element may be comparatively small, when placed in the context of the cumulative burden, it may become the proverbial "straw that broke the camel's back."

At some point, the "pancaking" of surcharges described in D.02-07-032 may lead to complete business failure, or at least relocation outside of California where the cost level faced either under the DA or bundled option is too burdensome to permit ongoing business viability. Various DA parties testified regarding the economic hardships they face in California and further hardship to their business, including potential relocation to other states) if the DA cap is raised.[41]

While TURN is correct that the DA CRS cap does not eliminate costs, but merely defers them, we believe there is still economic advantage to deferring the payment of such costs. We recognize that the cap does not eliminate DA CRS charges, but merely defers their payment to a future period. On a discounted present value basis, the DA customer still remains liable for the full DA CRS. Nonetheless, the deferral of payment can prove beneficial for DA customers to the extent that current cash flow is not required to pay off immediately the high undercollections that have accumulated. DA customers may discount future streams of costs or savings at varying levels associated with the relative economics of DA versus bundled service.

The question of DA economic viability is not as simple, however, as performing the mathematical exercise comparing DA and bundled charge levels at a particular point in time. The economic viability comparisons are complicated by non-price terms and factors that may influence a customer's choice between remaining on DA versus returning to bundled service. For example, even though bundled service may offer a lower cost option at one point in time, bundled service also entails certain restrictions limiting future flexibility to benefit from unforeseen competitive DA price movements that may be more advantageous in the future. The Commission has recently issued D.03-05-034 prescribing restrictions that would limit a DA customer seeking to return to

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[41] Strategic Energy / Lacey, Ex. 171, Attachment SEL-2; UC / CSU / CCLC, Ex. 176.

bundled service from taking advantage of such movements in prices. Thus, depending on how much value is ascribed to the competitive flexibility that DA offers, a DA customer may choose to retain the DA option even though the current price comparison with bundled service may not clearly favor DA.

For any DA customers are already facing marginal financial conditions, such an increase might cause them either to relocate outside of California, taking jobs with them, or in more extreme cases, to experience business shrinkage or failure. DA customers with lower cost bundled service alternatives may abandon DA for bundled service if the cap is raised. In the case of other DA customers with stronger financial positions or that are less energy-intensive users, some increase in the cap may be tolerable for the present time. In any case, we find it unnecessary at least at this point, to place a heavier burden on the cap to test how far DA will be impaired. If a cap increase had been found necessary in order to provide for repayment to bundled customers within the DWR contract life, we would have been inclined to entertain such necessary increases in the cap. At least until the next schedule reassessment of the cap, however, we conclude that retaining the cap at the existing 2.7 cents level will still enable bundled customers to be repaid no later than the end of the contract term. Thus, an appropriate balance of goals favors holding the present course for now with respect to the 2.7 cents cap.

8. Allocation of the DA CRS Undercollection to Bundled Customer Groups

In D.02-11-022, we adopted TURN's recommendation that any financing of the cap shall be retained with the same customer classes that benefit from the cap.[42] On February 5, 2003, a Petition for Modification was filed by CLECA seeking clarification from the Commission of this provision to state that the loan is to be provided by bundled customers generally to DA customers generally, without specification by customer class. Parties have addressed the issue of how to implement this provision of D.02-11-022 relating to the allocation of the DA CRS financing of the cap as part of this proceeding.

a) Parties' Positions

CLECA questions whether the term "financing" as used in D.02-11-022 refers to the interest costs associated with any loan or to the entire loan. CLECA argues that the answer has very substantial ramifications for bundled customers in the Large Power class. If the DA CRS were implemented to spread the shortfall as broadly as possible across bundled sales, the effect on any particular customer is quite small. If it is implemented to concentrate the cost of the shortfall caused by the application of the cap to Large Power DA customers, on the bundled customers in that class, CLECA argues, the cost to some bundled customers would be significantly increased while others would bear essentially no part of the burden. CLECA contends that TURN's proposal to retain the shortfall within customer classes and / or rate groups on the basis of the percentage of direct access load in each class or rate group would unduly punish bundled industrial customers.

DA service was available to all utility customers in 2001 until its suspension effective on September 20.[43] CLECA argues that there is no reason

[42] D.02-11-022, p. 117 (slip op.).

[43] Barkovich, CLECA, Ex. 167, p. 21.

why bundled customers in a class or rate group that happens to have a significant amount of direct access load should bear a greater share of the CRS undercollection burden than bundled customers in other classes. Industrial bundled service customers are no more responsible for the decision of some customers to choose direct access than are bundled residential customers. CLECA notes that the subsidy created by several other programs, the benefits of which are only available to one customer class, are explicitly spread to all customers. The costs of these programs are explicitly spread to all bundled sales without regard to participation levels by customer class or rate group.

Further, unlike the CRS shortfall, these programs do not contemplate any repayment obligation by the beneficiaries, but are simply subsidies covered by other customers and sales. In contrast, the CRS undercollection is a loan from bundled customers to direct access customers. It is not a subsidy or payment, but will be repaid with interest.

CLECA witness Barkovich testified that the allocation of the shortfall on the basis of direct access sales by customer group would have a severely disproportionate impact on Edison's TOU-8-Sub customers.[44] Using CLECA's recommended Scenario 14 results, the indicated maximum undercollection would result in an impact of roughly 0.3¢/kWh if spread to all bundled sales uniformly, but would cause a more significant 1.7¢/kWh impact on the bundled service customers in TOU-8-Sub if spread on the basis of the TURN proposal. The impact on these customers is nearly six times as great under the TURN approach. Further, if another scenario is adopted, or if the

[44] Barkovich, CLECA, Ex. 167, p. 23.

maximum undercollection exceeds that indicated in Scenario 14, the adverse result is magnified. Adoption of the Base Case Scenario 6 maximum undercollection of $505 million would result in a rate impact on these TOU-8-Sub bundled service customers of well in excess of 4¢/kWh,[45] nearly as much as some of them were paying for their full utility service in 2000 before the energy crisis hit California.

CLECA argues that there is no logical basis to impose this sort of penalty on the very large industrial customers who bore the brunt of the Commission's surcharge increases in January and June of 2001, and that such an allocation of the CRS shortfall would be bad public policy, and bad for the State's economy.

SDG&E agrees in principle with CLECA that DA CRS undercollections should be spread across all bundled customers, but proposes one modification to provide that the undercollection be allocated in proportion to customers' non-exempt bundled usage. SDG&E thus proposes to exclude residential usage up to 130% of baseline, medical baseline usage and CARE usage that are currently exempt from commodity charge increases beyond the 6.5 cents/kWh charge that existed on February 1, 2001, pursuant to AB 1X.

PG&E proposes that any future reduction in bundled customer bills associated with a DA DWR power charge shortfall that occurs while bundled customers are on frozen rates be allocated back to all bundled load equally.[46] Under its current tariffs, PG&E argues that no subset of bundled

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[45] This figure is simply 1.7¢ times the ratio of $211 million to $505 million.

[46] Ex. 155, p. 1-4.

customers has contributed more to covering the DA shortfall than has another. PG&E's shortfall will not cause any immediate change to bundled customers' electric bills, what PG&E bundled customers' pay for electricity will remain at their current, frozen levels.[47] Just as is the case currently, PG&E's remittance obligation to DWR will be met through the combination of the revenues from bundled and direct access customers, with any remaining amount constituting headroom. PG&E argues that since no one subset of customers has contributed more to covering the shortfall than any other, it follows that when direct access customers begin to make up this shortfall, there is no basis for using this "make up" revenue from direct access customers to lower one subset of bundled customers' bills more than another.

Since any assignment would have nothing to do with costs paid for by bundled customers, PG&E argues, the assignment would in no way relate to any additional burden borne by various groups of bundled customers due to the DA DWR power charge shortfall. PG&E thus argues it would make no logical sense to use this artificial assignment as a basis for differing reductions later, because those reductions would confer a very real benefit.

In short, there is no reason at this point for the Commission to make any determination as to which of PG&E's bundled customers bear the burden of any DA DWR power charge, because under current frozen rates, which will not be changed to reflect the shortfall, there is no basis to conclude that any given subset of bundled customers bears more of the burden than do others.

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[47] Ex. 155, p. 1-4.

ORA acknowledges that extreme impacts on customer charges would be caused by defining the term "class" too narrowly for purposes of implementing class allocation of the undercollection as required by D.02-11-022. Such impact would totally cancel any decrease customers will receive when the surcharges are eliminated in A.03-01-019. This impact would decrease as the CRS itself goes down, but it may persist for several years under some scenarios. This would render bundled customers uncompetitive with direct access customers in the same industry for some time. Given that the issue of business failures and customers moving out of state were concerns that underlie the need for the cap,[48] such a result would be contrary to the intent of D.02-11-022.

Because of these problems, ORA proposes that only two major "classes" be defined, distinguished as core and non-core, for allocating the CRS undercollection. Similar to the firewall for CTC purposes in Assembly Bill (AB 1890), the core class would include all residential and small commercial customers under 20 Kilowatts ("kW") in load. ORA's definition would depart somewhat, however, from that of AB 1890 by including agricultural customers under 20 kW in the core class. Core would also include streetlighting customers. Because the penetration of direct access in the agricultural class in general is quite low for all three utilities, ORA proposes that the agricultural customers under 20 kW not be held responsible for the undercollections caused by the large industrial customers.[49]

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[48] See D.02-11-022, p. 110 (slip op.).

[49] The penetration of direct access among agricultural customers below 20 kW in load is extremely low. But it is not particularly high among agricultural customers over 20 kW

Footnote continued on next page

No matter how classes are defined, bundled customers on tariffs with low direct access penetration that are grouped with customers on tariffs with high direct access penetration will complain of unfairness. While spreading the undercollection uniformly to all customers would minimize this inequity, doing so would moot the protection that D.02-11-022 was attempting to provide.

ORA argues that defining these two broad classes would not result in cost impacts to bundled non-core customers much different than if the undercollection had been allocated to all customers, at least for SCE. Using SCE's workpapers in A.03-01-019, ORA calculates that customer charges would increase by about 0.7 cents per kWh if the undercollection were allocated uniformly to all customers. If the undercollection were retained within separate core and non-core classes as defined by ORA, core rates would remain virtually unchanged and non-core rates would increase by approximately 1.0 cents/kWh.

ORA proposes a non-core class that would comprise customers with over 20 kW in load. The CRS undercollections from the core class would be allocated to the bundled core customers, and the undercollections from the non-core class would be allocated to the bundled non-core customers. (See ORA Ex. 162, pp.10-12.)

ORA characterizes its recommendation as a pragmatic approach preserving the intent of D.02-11-022 by affording protection from the effects of a CRS cap to customer classes with low rates of DA participation. ORA's proposal is intended to protect small customers and help moderate large increases that

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in load either. ORA is not opposed to including the entire agricultural class as well as streetlighting customers in the "core class."

industrial customers could face if the CRS shortfall was allocated by customer class or industrial tariff schedule.

TURN and SCE support the core/non-core split for the purposes of allocating CRS undercollections. (TURN Ex. 169, pp. 14 – 15; SCE Ex. 160, pp. 15 ff.) ORA's proposal is a modification of the original proposal made by TURN adopted in D.02-11-022 that was designed to protect customer classes with a low rate of DA participation and to ensure that customer classes with low rates of participation in DA do not subsidize those classes with higher rates of participation

ORA broadened the definition of customer classes originally proposed by TURN,[50] resulting in smaller increases for industrial customers than if the undercollection had been allocated to classes as currently defined while still protecting customers with low rates of DA participation. (SCE Ex. 160, Table #2.)

b) Discussion

We hereby adopt the core/noncore allocation approach proposed by ORA with certain modifications as noted below. The ORA approach preserves the intent of D.02-11-022 concerning the assignment of the undercollection among different categories of bundled customers. The intent was to ensure that customer groups with low rates of participation in Direct Access (primarily residential and small commercial) do not subsidize customer groups with high levels of participation. ORA's approach is consistent with this intent, protecting small customers while helping to moderate large increases that

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[50] ORA, Ex. 162, pp. 10-11.

industrial customers could otherwise face if a strict allocation of the DA CRS by customer class or industrial tariff schedule were used.

ORA's approach modifies the original TURN financing proposal by broadening the definition of customer class. This modification offers a pragmatic solution that balances the effects of the undercollection on both small and large customer groups.

Assuming the Commission assigns cost responsibility for the DA CRS undercollection differentially between classes, PG&E seeks to be allowed to deviate from ORA's proposed 20 kW criterion, and instead, to divide customers along the lines of its existing tariff schedules. The 20 kW threshold does not conform to PG&E's tariff categories. PG&E thus proposes that all residential and streetlighting rate schedules, and commercial rate schedules commonly referred to as Small Light and Power (Schedules A-1, A-6, TC-1, E-36 and A-15) be placed into core.

We shall grant PG&E's request to divide customers along the lines of its existing rate schedules for core / noncore allocation purposes. Defining the core / noncore groups by rate schedule will eliminate the need to divide current rate schedules into subsets for the funding of the DA CRS, minimizing the numbers of different pricing scenarios possible, minimizing billing system required changes, and reducing the potential for customer confusion. With these revisions the core / noncore split still accomplishes our goals by isolating smaller customers from the effects of capping the DA CRS for large customers.

ORA's allocation approach calls for a pooling of DA default risk between the core and noncore sectors. We find such a pooling approach to be in conflict with the basic premise underlying the core / noncore approach, namely, to maintain separate account of the respective core and noncore share of undercollections. We thus decline to adopt this provision of ORA's allocation proposal. Any unreimbursed DA CRS obligations associated with defaults of DA customer accounts shall be reallocated to the remaining DA customers applicable to the respective core or noncore category to which they belong. Noncore customers' DA CRS shortfall shall be allocated back to noncore bundled customers, and core customers' DA CRS shortfall shall be allocated back to core bundled customers.

ORA is not opposed to including the entire agricultural class in the core category, even for agricultural classes that are over the 20 kW limit. PG&E agrees to the inclusion of all streetlighting and agriculture classes within the core grouping, if the Commission adopts a core/noncore allocation approach. SDG&E opposes including the entire agricultural class within the core grouping as arbitrary. As noted in the comments of the Farm Bureau, agricultural rate schedules are divided only upon the level of demand that the customer's motor draws. The motor size does not relate to the amount of usage throughout the year. Thus, it would be impractical to attempt to divide agricultural customers based on a 20 kW load criterion. Also, the impacts of including all agricultural classes does not materially change the relative share of costs allocated between core and noncore. We shall therefore include all streetlighting and agricultural classes within the core grouping.

As noted in certain parties' comments on the ALJ's Proposed Decision, proposals are currently under consideration before the California Legislature as AB 428 for core/noncore separations of electric customer categories that differ from the size criterion and designated purposes as proposed in this proceeding by ORA. SDG&E argues that the Commission's attempt to define the terms core/noncore at this juncture will only inject confusion and possible instability as further industry transition is contemplated. In recognition of the possibility that the legislative analysis of this issue could result in different definitions of core and noncore categories than those contemplated in this order, AREM suggest that any resolution of this issue here be adopted only on a provisional basis.

Particularly in view of legislation pending in AB 428, we shall adopt core/noncore allocations in this order only on a provisional basis. To the extent that any subsequent legislation defines the criteria for core/noncore categories that are inconsistent with the provisional allocations we adopt in this order, we agree that our provisional solution may need to be reexamined and potentially modified to conform any subsequent legislation that is enacted incorporating different measures or definitions of core and noncore customers.

VII. Order of Collection of DA CRS Elements

For DA customers both the ongoing CTC charge and the DA DWR power charge (as well as the bond charge once it is collected from direct access customers) will be recovered via the capped DA CRS. Since not all of these charges fit under the cap, this requires that the charges be deemed to be collected in some order, in order to determine how the shortfall should be tracked for ratemaking purposes.

In D.02-11-022, the Commission determined an order in which the DWR bond charge, the ongoing CTC, and the DA DWR power charge should be deemed to be collected. The Commission determines that the DWR bond charge should be deemed to be collected first, the DA DWR power charge second, and the ongoing CTC charge third.[51]

A. Parties' Positions

PG&E recommends that the order of collection be modified, so that the DWR bond charge be deemed to be collected first, ongoing CTC be deemed to be collected second, and the DA DWR power charge be deemed to be collected third.[52] PG&E argues that changing the collection order will have no substantive effect on customers' charges, but will significantly simplify the necessary cost recovery mechanisms.[53]

The order in which the charges are deemed to be collected does not make any substantive difference because it does not affect how much money is collected from either bundled or direct access customers. Regardless of whether the shortfall is labeled as (1) a direct access obligation to reimburse bundled customers for DWR power charges attributable to direct access customers but borne by bundled customers, (2) a direct access obligation to reimburse bundled customers for ongoing CTC amounts attributable to direct access customers but borne by bundled customers, or (3) a combination of both, the shortfall is the same. DWR receives the same amount from PG&E regardless of the level of the DA DWR power charge component in the DA CRS.

Further, regardless of its label(s), the shortfall occurs because the amount collected from direct access customers is not sufficient to cover the

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[51] D.02-11-022, pp. 121-22.

[52] Ex 153, pp 1-7 – 1-8.

[53] Ex 153, pp 1-7 – 1-8.

indifference amount. In particular, therefore, any shortfall should bear the same interest rate, regardless of how it is broken down for regulatory tracking purposes, and regardless of the regulatory label applied to it.

However, even though there is no substantive difference depending on whether the DA DWR power charge or the ongoing CTC is deemed to be collected second (after the DWR bond charge), PG&E contends that the cost recovery mechanisms necessary if the DA DWR power charge is ordered second and ongoing CTC third will be more complex. PG&E claims that this resulting additional complexity provides no substantive benefit, and therefore should be avoided.

B. Discussion

We agree with PG&E that changing the order of collection of the DA CRS elements will simplify the necessary accounting mechanism. DWR was the only party to raise any objection to PG&E's proposal to change the order of collection. We are not persuaded that changing the order of collection prevents DWR from correctly accounting for the remittances it has already received. PG&E proposed order of collection provides a simpler solution, and we hereby adopt it.

Regardless of whether the DA DWR power charge is second or third, a shortfall is expected. It will be larger if the DA DWR power charge is ordered third but the shortfall, and therefore the need to track the shortfall, is not avoided by ordering the DA DWR power charge second. Thus, since there is a DA DWR power charge shortfall in any event, there is no difference with respect to the DA DWR power charge cost recovery mechanism whether the DA power charge is ordered second or third.

However, the effect of the ordering on the ongoing CTC cost recovery mechanism is quite different. If the ongoing CTC power charge is ordered second, no ongoing CTC shortfall is expected, because the sum of the bond charge and the ongoing CTC are not expected to approach the DA CRS level. Thus, if the ongoing CTC is ordered second there is only one shortfall to track, the DA DWR power charge shortfall, and it is tracked in the DA DWR power charge cost recovery mechanisms.

Not having a shortfall to track in the ongoing CTC ratemaking mechanisms simplifies them substantially. One component can be set for each customer class, applicable to all customers who pay the charge, regardless of whether they are bundled are direct access. Only one balancing account is necessary, to track the difference between revenues from the ongoing CTC rate component, and the costs to be recovered via that component.

By contrast, if there is an ongoing CTC shortfall, then different ongoing CTC components need to be set for bundled and direct access customers. The direct access ongoing CTC component will be set with reference to the adopted DA CRS level, and then the bundled ongoing CTC component will be set with reference to the shortfall created by the direct access ongoing CTC.

If the ongoing CTC is ordered third, two amounts relating to ongoing CTC need to be tracked, not just one. Not only does the difference between ongoing CTC revenues and costs need to be tracked, but also the ongoing CTC shortfall resulting from the cap on the DA CRS needs to be tracked. This complexity, too, is avoided if ongoing CTC is ordered second.

So long as there is a DA CRS cap, bundled customers' cost responsibility for the DWR power charge revenue requirement in any given year will be dependent on the amount contributed by direct access customers. But one can avoid having a second cost component, ongoing CTC, complicated in the same way.

By adopting PG&E's proposal, accounting for continuing DA load is also simplified. Continuous direct access customers do not bear responsibility for the DA DWR power charge. Therefore, they can bear the full ongoing CTC component.[54] There is no need to distinguish whether these customers be charged the "capped" ongoing CTC charge like most direct access customers would, or the full ongoing CTC charge.

In the case of SCE, there is an additional element, the HPC in the DA CRS collection process. In D.02-11-022, we authorized SCE to recover the HPC second in order after the DWR Bond Charge. Thus, in keeping with this requirement, the effect of the change in the sequence of collection ordered herein will mean that SCE collects CTC third in order after the DWR bond charge and the HPC.

DWR, in its comments, notes that without a final amount yet determined for CTC, the utilities will not know what residual amount of DA CRS collections remains available to apply to the DWR power charge. As a result, DWR expresses concern that the utilities are likely to resist remitting any amount from DA CRS collections to apply to the DWR power charge, causing bundled customers to pay higher rates to continue financing this portion of the DWR power charge. To guard against this result, DWR proposes that the change in the order of collection not be made effective until the Commission adopts a final CTC element.

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[54] *See* RT p. 2031-2032, (McDonald / DWR).

As noted by DWR, in the absence of final CTC values adopted for 2001-03, the utilities will not know what amounts remain available to remit to DWR. We thus shall adopt DWR's suggestion that the implementation of the revised collection sequence become effective concurrent with the final determination of the CTC amounts applicable for 2001-03. In this way, a one-time adjustment for remittances due to DWR for the effects of past CTC can be made, and any going-forward remittances to DWR will properly reflect the residual amounts available after collections for CTC.

VIII. Tracking Mechanism to Ensure Proper Allocation of DA Default Between Core and Noncore Classes

A. Parties' Positions

ORA recommends that the Commission adopt a tracking mechanism as set forth in Attachment A of its testimony to facilitate reallocating the defaulted unpaid balances of DA customers that terminate utility service altogether to other DA customers. This tracking mechanism is intended to allow those defaults to be shared by all DA customers. Defaults from non-core DA customers would be allocated partly to core direct access customers, and vice versa.

ORA's proposed CRS tracking account would contain two subaccounts. One would track debts owed by core DA to core bundled customers, and the other would track debts owed by non-core DA to non-core bundled customers. This debt is paid down primarily through the credit entries in line 2. If direct access load decreases, the credit entries in line 2 will be reduced, potentially extending the repayment period. However, if the decrease in direct access load is caused by a direct access customer moving to bundled service, there is a credit entry for the CRS make-up charge in line 3. That entry should be sufficient to compensate for the smaller future credit entries in line 2, thus leaving the repayment period unchanged, assuming the CRS itself does not change.

If, on the other hand, a direct access customer terminates utility service altogether without paying the required make-up charge, then the repayment period is extended. But the impact of that extension is allocated between the core and non-core class in lines 4 and 5. Thus, for example, if a core direct access customer defaults on the make-up charge, part of that responsibility is reallocated to the non-core class through a credit entry in line 4 (corresponding to the debit entry in line 5 of the non-core subaccount), reducing the otherwise applicable debt owed by the core direct access to core bundled customers. Thus, though the repayment period is extended because of smaller credits on line 2, the credit entry on line 4 reduces this extension somewhat. Line 5 in the core subaccount is a debit entry (corresponding to the credit entry on line 4 of the non-core subaccount) that would increase the repayment period in the event of default by a non-core customer.

A potential downside of this mechanism is that defaults by non-core direct access customers will increase the length of the loan for core customers, increasing risk to bundled core customers. ORA believes that the increased protection of having more direct access customers bear the default risk more than compensates for the reduced protection associated with allowing defaults to cross classes.

ORA recommends that the Commission adopt accounting provisions similar to those presented in Attachment A of its prepared testimony. While an accounting mechanism that clearly tracks the obligations of direct access customer will facilitate accurate repayments, the existence of such a system will not necessarily mitigate default risk.

PG&E agrees with ORA that the shortfall associated with the DA CRS cap must be tracked, and proposes the title of the "Direct Access Shortfall Account."

B. Discussion

We agree with ORA that an accounting and tracking mechanism is needed to ensure proper allocation of undercollections between core and noncore customers. We shall incorporate the general accounting requirement principles proposed by ORA as incorporated in Appendix B hereto. SCE has filed a motion to adopt a settlement of the issues in A.03-01-019, including a proposed allocation to classes of the 2001 – 2003 DA CRS undercollection, assumed to be $325.6 million, that is incorporated in the settlement rates. The allocation to classes is not uniform on a per kWh basis. The settlement provides that any difference between the assumed CRS undercollection of $325.6 million and the actual undercollection will be allocated based on whatever methodology is adopted in this proceeding. ORA believes that it may become necessary to track the first $325 million of the CRS undercollection and any subsequent undercollections separately. The tracking mechanism that ORA proposed in its opening and rebuttal testimony (Exhibits 162 and 163) may not be able to accomplish this. Though ORA's proposed mechanism in Exhibit 163 does allow for separate tracking of the rate freeze and post-rate freeze portions of the undercollection, it assumes the rate freeze portion is allocated uniformly, which the settlement in A.03-01-019 does not do.

ORA proposes that the Commission hold a workshop to further develop the record on how to account for the growth and repayment of the CRS undercollection, and how to allocate it to classes. ORA believes such a workshop is appropriate particularly now that a settlement in A.03-01-019 has partially resolved the allocation of the CRS undercollection to classes. We agree that a workshop is appropriate to address these accounting implementation and coordination issues in more detail. We shall therefore direct the ALJ to schedule a workshop for this purpose.

IX. Frequency of Subsequent Reviews and Readjustments of DA CRS

Because forecasts are inherently subject to uncertainty, we must provide a means for ongoing periodic review of the DA CRS including prospective amounts and amortization of the undercollection level to assure that bundled customers are fully reimbursed by no later than the end of the DWR contract term. With respect to the process for updating the DA CRS, two separate issues arise. First, an ongoing process is required for updating of the DA CRS annual prospective cost responsibility obligation. Second, an ongoing process is required for reevaluating and adjusting, as necessary, the level of the DA CRS cap to assure that the goal of full payback by 2011 is achieved.

As stated above, we shall coordinate with the redetermination of the 2003 DWR revenue requirement in A.00-11-038 et al. to finalize the undercollection for 2001-02 and the prospective DA CRS obligation for each utility for calendar year 2003. Each subsequent year through the remaining life of the DWR contracts, an annual DA cost responsibility obligation must be determined in coordination with the bundled customer revenue requirement for DWR contract costs to assure consistent allocation between bundled and DA load and proper interest accruals on the undercollection. Unless the allocation between bundled and DA load is made based upon consistent assumptions in each annual update, the requirement for bundled customer indifference will be compromised.

A recurring process is also required for review of the adequacy of the DA CRS cap level. For purposes of such review, however, we conclude that the frequency need not necessarily be once a year. The process of reassessing the cap in this phase of the proceeding has been resource intensive, and we find no value in conducting such an intensive review more frequently than is warranted.

Since the cap already anticipates that collections will occur over multiple years, variances in forecast costs over a single year will not necessarily require annual changes in the cap level. With the establishment of DA CRS tracking accounts, any variance between the authorized DA CRS obligation and collections under the DA CRS caps will be captured and accounted for with interest. On the other hand, it would not be prudent to keep the 2.7 cents cap in place without reasonable periodic reassessment and readjustment, as necessary to make sure that more current forecasts remain consistent with our expectation of full payback by 2011. We shall thus authorize the following measures to balance these concerns. In the modeling scenarios performed by Navigant, three variables were found to be particularly sensitive to projected payback period, namely, natural gas prices, sales prices for off-system sales, and levels of DA load. Thus, in each annual update proceeding for DWR and DA CRS revenue requirements, we shall examine changes in the level of each of these variables. To the extent that any one of these variables deviates significantly from the forecast assumptions underlying this order, we shall order the assigned ALJ to take further procedural steps to consider the need for a reassessment of the level of the DA CRS cap. We define a significant deviation as a magnitude of variance distinguishing Navigant's low and base case assumptions, as presented in this proceeding.

In the absence of a need to revisit the cap earlier as a result of a significant variance in one of these identified forecast variables, we conclude that reassessment of the cap once every two years is sufficient to assure the payback schedule is met. We shall thus authorize the next regular reassessment of the DA CRS cap to be initiated two years from the effective date of this order.

By requiring subsequent reassessment on this basis, we can readjust the cap, as necessary, to reflect updated forecasts and to maintain assurance of full payback by 2011. This approach also will provide greater stability to DA customers seeking to negotiate power arrangements, and will avoid unnecessary expenditure of parties' and Commission scarce resources.

To the extent in subsequent reviews, if we conclude that the existing cap remains sufficient to meet our established goals for payback by the end of the contract term, we shall continue to leave the caps in place. To the extent that updated review of expected payback period indicates that a revision in the DA CRS cap is required to keep the repayment schedule on track, we shall adjust the cap of one or more of the utilities, as necessary.

X. Rehearing and Judicial Review

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

XI. Comments on the Proposed Decision

The Proposed Decision of Administrative Law Judge Thomas R. Pulsifer was filed and served on parties on May 20, 2003. Comments on the Proposed

Decision were filed on June 9, 2003, and reply comments were filed on June 16, 2003. We have taken the comments into account as appropriate, in finalizing this order.

XII. Assignment of Proceeding

Carl W. Wood and Geoffrey F. Brown are the Assigned Commissioners and Thomas Pulsifer is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. D.02-03-055 determined that as a condition of retaining the DA suspension date of September 21, 2001, a surcharge must be imposed on DA customers sufficient to make bundled customers economically indifferent between a DA suspension date of July 1 versus September 21, 2001.

2. By D.02-11-022, an interim DA CRS cap of 2.7 cents/kWh was adopted pending further study and possible revision effective on and after July 1, 2003.

3. A reasonable criterion in setting a cap for purposes of preserving bundled customer indifference with respect to DA load migration is to ensure full payback of the DA CRS undercollection no later than the end of the DWR contract term expected to occur in 2011.

4. To provide a framework for analysis of potential future DA CRS obligations and the resulting effects of alternative caps, Navigant produced a range of 24 separate modeling scenarios, incorporating the “total portfolio indifference” approach.

5. The Navigant scenarios are based upon three sets of resource assumptions, comprising a low, high, and base case in which the sensitivities of the undercollection and payback period are tested with respect to changes in key variables relating to DA load, natural gas prices, new generation, and CTC levels.

6. While certain parties support use of the base case for evaluating DA CRS payback periods, no support was provided to show that the assumptions underlying the base case (other than DA load levels) have a greater overall likelihood of occurrence relative to the low or high case.

7. No party supported the high case as offering more reliable forecast assumptions than either the low or base case.

8. Of the modeling runs produced by Navigant, the scenarios based upon the low case with off-system sales valued at 100% of market-clearing price represent the most likely forecast assumptions relating to future DA CRS requirements for purposes of evaluating cap levels, as represented in Navigant Scenarios 13 through 16.

9. Although Navigant's low case scenarios generally are more reliable than its base case scenarios, the base case assumptions concerning DA load are more defensible than either the high or low base case assumptions for this variable.

10. AREM presented a scenario combining the base case assumption for DA load with the other assumptions underlying the low case, essentially as depicted in Navigant Scenario 14, and computing the effects of this combination of assumptions as "Scenario 25."

11. Based on the AREM Scenario 25 results, payback of the DA CRS undercollection would occur within a five-year period for PG&E, within a four-year period for SCE, and within a two-year period for SDG&E.

12. Although Navigant's initial runs did not identify a single actual 2001-2002 recorded undercollection applicable to DA CRS, it subsequently submitted revised calculations that identified values for the actual undercollection applicable to each utility.

13. The updated data regarding estimated 2001-2002 undercollection values submitted by Navigant provide a reasonable approximation for the limited purposes of analyzing the expected payback of DA CRS undercollections subject to further verification of the actual values.

14. The substitution of the updated data regarding actual 2001-2002 recorded undercollection values submitted by Navigant still provides for expected DA CRS payback periods prior to 2011, reflecting a DA CRS cap of 2.7 cents.

15. Based upon forecast results presented in Scenarios 13 and 14 as further refined by Scenario 25, the goal of realizing full bundled customer payback of the DA CRS undercollection by the end of the DWR contract term in 2011 can be satisfied by maintaining the current 2.7 cents cap for each utility, subject to periodic review and adjustment as necessary.

16. In order to remain indifferent with respect to the DA CRS undercollection, bundled customers must be fairly compensated for the time value of money through an appropriate interest rate.

17. To the extent the utility rate of return includes a component for utility stockholders' equity, its risk-and-return is not a relevant indicator of the risk and return applicable to a debt-related obligation such as the DA CRS undercollection.

18. The fact that a three-month commercial paper rate may compensate a utility for financing certain types of balancing accounts does not necessarily indicate that such a rate is indicative of bundled customers' cost of money associated with financing the DA CRS undercollection.

19. The length of time that balancing account is expected to exist is not the sole determinant of the appropriate interest rate factor to be applied, particularly in the case of the DA CRS where financing is not provided by the utility, but

rather by bundled customers, who do not necessarily have the same access to the capital markets.

20. Since the source of financing of the DA CRS undercollection is bundled customers, and not the utility, the relevant interest rate is based upon the risk-adjusted cost of money experienced by the bundled customer rather than financing sources to which a utility may have access.

21. Because the DA CRS undercollection is long term in nature, the most appropriate indicator of the bundled customers ‘cost of money is a long-term debt instrument rather than short-term forms of debt such as three-month commercial paper or a consumer revolving line of credit.

22. The broadest based measure of long term debt in this record is the long term corporate debt based on Moody’s Investors Service Corp., with a 10-year average of 7.6% and 7.1% average for 2002.

23. A reasonable proxy for bundled customers’ cost of money for the financing of the DA CRS undercollection is an interest rate based on the long-term corporate debt measure as indicated by the Moody’s Investors Service Corp., and reported in the Farm Bureau’s testimony.

24. For purposes of applying an interest rate factor to the DA CRS for the 2001-03 period, the average 2002 long-term corporate interest rate factor of 7.1% reported by Moody’s Investor Services, Inc. represents the most reasonable proxy in the record.

25. For purposes of assessing the effects of interest in connection with a longer-term forecast of the DA CRS payback period, the 10-year average long-term corporate interest rate factor of 7.6% reported by Moody’s Investor Services, Inc. represents the most reasonable proxy in the record.

26. Because business customers typically may deduct interest for income tax purposes, an after-tax interest rate provides an appropriate basis for purposes of accruing interest on their share of the DA CRS undercollection.

27. Because residential customers, typically cannot deduct interest for incremental borrowings, a before-tax interest rate provides an appropriate measure for purposes of accruing interest on their share of the DA CRS undercollection.

28. In D.02-07-032, the Commission found that there should be a cap on the total surcharge levels imposed on DA customers (including the impact of any changes to the PX credits) to avoid making DA uneconomic.

29. The Commission stated its policy in D.02-03-055 that there is value to California in maintaining DA. In D.02-07-032, the Commission found that failure to consider an overall cap would be inconsistent with this policy.

30. A appropriate approach for setting the DA CRS cap for the period subsequent to July 1, 2003 is one that takes into account the dual goals of achieving bundled customer indifference and avoiding making DA uneconomic.

31. Because of the diversity of DA contracts and customers, no single cap will necessarily prevent the return of any DA customers to bundled service, or prevent any DA business failure or relocation outside California.

32. No party justified that any cap lower than 2.7 cents is warranted in order to balance the goals of achieving bundled customer indifference whole avoiding making DA uneconomic.

33. The continuation of DA provides jobs and enhances the tax base in support of the California economy, and promotes the diversity of energy supplies within California.

34. For certain SCE rate schedules, bundled service is expected to be cheaper than DA even at a 2.7 cents cap after the PROACT reductions contemplated in A.03-01-019 are implemented. Any cap increase now will risk further tipping the scales further in favor of leaving DA for bundled service.

35. For certain DA customers, particularly in energy intensive industries, increases in the cap will increase the risk of DA becoming unviable.

36. Given the risk that increases in the cap may create incentives to leave DA for bundled service, relocate out of state, or go bankrupt, and considering that the existing cap provides for payoff by 2011, maintaining the existing caps avoids risking erosion of DA levels while protecting bundled customers.

37. ORA's proposal to allocate between two broad classes, core and noncore, provides a reasonable approach to implement the intent of the Commission expressed in D.02-11-022 concerning the assignment of the undercollection among different categories of bundled customers.

38. Under ORA's proposal, core would include residential and small commercial under 20 kW and noncore would cover customers over 20 kW.

39. ORA proposals for accounting for the DA CRS undercollections provide a reasonable means of assuring that the allocation between core and noncore customers is properly implemented.

40. The default in obligation of DA customers associated with the noncore class properly remains an obligation exclusively to be made up by other customers in the noncore class. The default in obligation of DA customers associated with the core class properly remains an obligation exclusively to be made up by other customers in the core class.

41. Because PG&E's tariffs do not precise correspond the 20 kW criterion proposed under ORA's allocation, it is reasonable for PG&E to modify the

allocations as necessary to conform to its own tariff classes even though they may deviate somewhat from the 20 kW level.

42. It is reasonable to include the entire agricultural class and streetlighting class in the core category for purposes of assigning DA CRS undercollections.

43. Periodic reevaluations of the DA CRS cap level will mitigate the risk of future DA CRS forecast error, and assure timely bundled customer payoff of undercollections.

44. Determination of final figures for the 2001-2002 undercollection and 2003 prospective revenue requirement for DA CRS have yet to be implemented in coordination with the DWR proceeding in A.00-11-038 et al.

45. The revised order of collection of DA CRS elements with CTC collected second and DWR power charge collected third will simplify the accounting and administrative process.

46. In keeping with the requirement in D.02-11-022, that SCE to recover the HPC second in order after the DWR Bond Charge, the effect of the change in the sequence of collection adopted in this order means that SCE collects CTC third in order after the DWR bond charge and the HPC.

47. Because the CTC element has not yet been finalized, it is reasonable to time the implementation of the revised order of collection of the DA CRS elements to coincide with the finalization of the CTC element for each utility.

48. Because the DA CRS undercollection for 2001-02 and the prospective 2003 DA CRS revenue requirement have not yet been finalized, a further process is required to coordinate finalization of DA CRS obligations with the redetermination of the 2003 DWR revenue requirement in A.00-11-038 et al.

49. Since the DWR proceeding in A.00-11-038 et al. does not address URG costs, a separate process is needed to examine URG costs and to adopt a CTC

component as prescribed under the total portfolio approach prescribed in D.02-11-022.

50. In order to assure proper coordination and timely finalization of the CTC components for the 2001-02 historic period and 2003 prospective period, it is reasonable to address those matters in this docket in coordination with the 2003 DWR revenue requirement redetermination in A.00-11-038 et al.

51. For prospective CTC determinations in 2004 and thereafter, it is reasonable to use the Energy Revenue Resource Account proceeding.

52. In order to assure consistent allocation of each DWR revenue requirements between bundled and DA load and proper interest accruals on the undercollection, it will be necessary to update the prospective DA cost responsibility obligation along with bundled customers' requirement for each new 12-month period as part of each DWR update proceeding.

53. Unless the allocation between bundled and DA load is made based upon consistent assumptions, the requirement for bundled customer indifference will be compromised.

54. Since the DA CRS cap already anticipates that collections will be extended over multiple years, variances in forecast costs over a single year will not necessarily require annual changes in the cap level.

55. To the extent that key resource variables (i.e., gas prices, DA load levels or off-system sales prices) deviate significantly from the forecast assumptions underlying this order, however, it may indicate that a reassessment of the cap is necessary to assure that payback goals are achieved.

56. In the event that key resource variables (i.e., gas prices, DA load levels or off-system sales prices) deviate from the levels assumed in this order by a significant degree at the time of the next annual DWR revenue requirement

redetermination, further procedural steps would be warranted to consider the need for a reassessment of the level of the DA CRS cap.

57. For purposes of defining a significant level of variation in the identified key resource variables, it would be reasonable to assume a variation on the order of magnitude between the base case and the low case as defined in this proceeding.

58. Absent a significant variation in key resource variables, as defined above, it is reasonable to limit a reassessment of the cap level to once every two years.

Conclusions of Law

1. This phase of the proceeding is focused on evaluating the DA CRS cap subsequent to July 1, 2003 rather than adopting total DA CRS revenue requirement elements.

2. The determination of the total authorized DA CRS level of the 2003 DWR power charge and 2001-2002 undercollections should be made in parallel with the overall determination of the total DWR revenue requirement in A.00-11-038 et al.

3. The adoption of a total authorized level of the CTC element comprising the DA CRS should not be finalized in this phase of the proceeding because further scrutiny of the utilities' proposed CTC calculations is warranted.

4. The task of finalizing CTC levels for the year 2004 and thereafter should be addressed in the ERRA proceeding for each utility.

5. SDG&E should amend its CTC calculation to be consistent with the total portfolio approach adopted in D.02-11-022, such that below-benchmark resources are included with above-benchmark resources.

6. The purpose of the DWR and CTC calculations presented in this phase of the proceeding is to provide a range of forecasts to evaluate the sensitivity of

variances in key resource inputs and cap levels in relation to DA CRS undercollections and resulting payback periods.

7. The Commission should determine the level of DA CRS cap that balances the criteria of preserving bundled customer indifference and maintaining DA viability.

8. The criteria for preserving bundled customer indifference should provide assurance that CRS undercollections resulting from the cap will be repaid in full to bundled customers, with compensatory interest, over a reasonable period of time.

9. A reasonable time period for full repayment of the DA CRS undercollection should not exceed the term of the DWR contracts, due to expire in 2011.

10. The modeling scenarios of forecast DA CRS levels prepared by DWR/Navigant provide an appropriate framework for evaluating the potential cumulative undercollections and time period required to achieve full pay back to bundled customers for each utility.

11. The 2.7 cents/kWh cap level should continue in effect for each utility during the period on and after July 1, 2003 subject to possible revision in the next DA CRS cap review proceeding to the extent necessary to balance the dual goals of preserving bundled customer indifference and preventing economic harm to DA customers.

12. In each periodic DA CRS cap review proceeding, the cap should be subject to adjustment, to the extent necessary to maintain that the goal of full bundled customer payback by the end of the DWR contract term in 2011. The process for periodic review and readjustment of the DA CRS cap for each utility should conform to the requirements of Ordering Paragraphs 19-21 below.

13. In order to preserve bundled customer indifference, an interest rate must be applied to the DA CRS undercollection that reasonably compensates bundled customers for the time value of money.

14. An interest rate corresponding the long-term cost of corporate debt of 7.1% as referenced in the testimony of the Farm Bureau offers a reasonable approximation of bundled customers' cost of money associated with financing the DA CRS undercollection.

15. The proposal of ORA to allocate the DA CRS undercollection based upon a core and noncore segregation of customers should be adopted (subject to modifications specified below) as a pragmatic approach to fairly allocating the undercollection while avoiding excessive increases in charges to any single class of bundled customers.

16. The proposal of ORA should be adopted to establish an accounting mechanism to track the DA CRS undercollections and to assure that the appropriate levels are allocated between the core and noncore customer categories.

17. In order to simplify the administrative and accounting process, PG&E's proposal to revise the order in which the respective DA CRS are deemed collected should be adopted so that CTC is collected second with the DWR power charge collected third.

18. In the case of SCE, the order of collection should be revised to sequence the HPC second and the CTC third.

O R D E R

IT IS ORDERED that:

1. The existing Direct Access (DA) cost responsibility surcharge (CRS) cap of 2.7 cents/kWh applicable to each of the three utilities shall continue to remain in effect for the period beginning on and after July 1, 2003. The 2.7 cents cap shall be subject to possible future adjustment, as deemed necessary to pay off the DA CRS undercollection by 2011, through periodic review as prescribed in Ordering Paragraphs 20 and 21 below.

2. The final recorded confirmation of the DA CRS undercollection for 2001-2002, together with the adoption of the final adopted allocation of 2003 DWR power charges to the DA CRS shall be determined and implemented on a parallel basis in coordination with the implementation of the 2003 DWR revenue requirement redetermination in Application (A.) 00-11-038. The Administrative Law Judges in both this docket and in A.00-11-038 shall coordinate as necessary to ensure the timely implementation of this process in connection with the DWR 2003 revenue requirement redetermination.

3. The proposal of the Office of Ratepayer Advocates (ORA) for allocation of the DA CRS undercollection on a core versus noncore basis is hereby adopted with modifications as noted below.

4. The core/noncore allocation shall incorporate the entirety of the agricultural classes and the streetlighting classes.

5. PG&E shall be permitted to deviate from the 20 kW allocation separation criterion as necessary to conform to its tariff schedule categories, so as not to require splitting customers within a single tariff schedule category.

6. The ORA core / noncore allocation shall be adopted on a provisional basis, subject to subsequent adjustment, as necessary, to conform to any subsequent legislative actions that may require reexamination of the categorization criteria or purposes for which the categories are established.

7. The proposal of ORA for implementation of an accounting mechanism to track the DA CRS undercollection to ensure the appropriate allocation between the core and noncore categories is hereby adopted in accordance with the principles incorporated in Appendix B hereto.

8. The ALJ shall schedule a workshop to address in further detail how to implement the accounting for growth and repayment of the undercollection in accordance with the core and noncore approach adopted in this order.

9. The interest rate on DA CRS undercollections shall be applied based upon the long-term debt rate index derived from Moody's Investment Services Corp., as referenced in the testimony of the California Farm Bureau Federation.

10. For the period 2001-02 and for 2003, the interest rate to be applied to DA CRS undercollections for PG&E and SCE shall be based on a 7.1% interest rate, representing the 2002 average corporate interest rate, as set forth in testimony of the California Farm Bureau.

11. The interest rate on DA CRS shall be applied on an after-tax basis for residential bundled customers and on a before-tax basis for other bundled customers.

12. For applying interest accruals on the DA CRS undercollection applicable to bundled residential customers, the 7.1% interest rate shall be accrued on a before-tax basis. For other bundled customers, the 7.1% interest rate shall be accrued on an after-tax basis, resulting in an after-tax rate of 4.22% (incorporating an after-tax factor of 59.46% based upon utility corporate tax rates

as computed by SCE). These interest rates shall remain in effect until the next annual DA cost responsibility redetermination when they shall be subject to updating.

13. The applicable long-term corporate interest rate to be used for 2004 shall be determined based upon updated data on long-term corporate interest rates using similar data sources as were used in this proceeding in connection with setting the DA cost responsibility obligation for 2004.

14. The proposal of Pacific Gas and Electric Company to revise the order of collection of the DA CRS elements is hereby adopted. Accordingly, the CTC element shall be deemed to be collected second in order after the DWR bond charge. The DWR power charge shall be deemed to be collected third in order after the CTC element.

15. Pursuant to the change in the sequence of collection ordered herein, SCE shall collect CTC third in order after the DWR bond charge and the HPC.

16. The change in the order of collection of CTC shall be implemented concurrently with the finalization of the CTC element for each of the utilities for 2001-02 and 2003.

17. The finalization of the CTC element of the DA CRS for the 2001-02 historic period and for 2003 prospectively shall be determined in a separate phase of this proceeding to be coordinated with the finalization of the 2001-02 DA CRS undercollection and prospective DWR power charge, as prescribed in Ordering Paragraph 2 above.

18. The finalization of the CTC element for year 2004 and thereafter shall be addressed in the ERRA proceeding.

19. The DA cost responsibility total obligation shall remain subject to annual redetermination in connection with the ongoing annual cost responsibility obligation annual redetermination of DWR revenue requirements.

20. In each annual update proceeding for DWR and DA CRS revenue requirements, to the extent that specified key variables deviates significantly from the forecast assumptions underlying this order, the assigned ALJ shall take further procedural steps to consider the need for a reassessment of the level of the DA CRS cap. The specified key resource variables are natural gas prices, DA load levels, and off-system sales levels. A significant deviation is defined as a magnitude on the order of the difference between Navigant's low and base case assumptions, as presented in this proceeding.

21. In the event that the designated key resource variables do not deviate by a significant event in the next DWR revenue requirement redetermination, the next reassessment of the DA CRS cap levels shall be scheduled to commence two years from the effective date of this order subject to periodic biannual review thereafter until the DA undercollection is eliminated.

This order is effective today.

Dated ____________________________, at San Francisco, California.

APPENDIX B

DIRECT ACCESS COST RESPONSIBILITY SURCHARGE TRACKING ACCOUNT REQUIREMENTS

Core Subaccount

The purpose of this subaccount is to track the debt owned by core direct access ("DA") customers to bundled core customers. Monthly accounting entries will be made as follows:

1. A debit entry representing the CRS obligation of core direct access ("DA") customers.
2. A credit entry representing the CRS payment by core DA customers.
3. A credit entry representing the CRS make-up payment made by core DA customers when they return to bundled service.
4. A debit entry representing the CRS uncollectable from core DA customers that default.
5. A debit entry representing the interest on the combined balance of lines 1 – 5 calculated using the applicable interest rate.

In months where the combination of lines 1 – 5 for the month produce a debit balance, the generation revenue requirement of core DA customers will be decreased by that amount, and the generation revenue requirement of core bundled customers will be increased by the same amount.

In months where the combination of lines 1 – 5 for the month produce a credit balance, the generation revenue requirement of core DA customers will be increased by that amount, and the generation revenue requirement of core bundled customers will be decreased by the same amount.

When the cumulative balance in this subaccount reaches zero, no further entries will be made.

Non-Core Subaccount

The purpose of this subaccount is to track the debt owed by non-core direct access ("DA") customers to bundled non-core customers. Monthly accounting entries will be made as follows:

1. A debit entry representing the CRS obligation of non-core DA customers.
2. A credit entry representing the CRS payment by non-core DA customers.
3. A credit entry representing the CRS make-up payment made by non-core DA customers when they return to bundled service.
4. A debit entry representing the CRS uncollectable from non-core DA customers that default.
5. A debit entry representing the interest on the combined balance of lines 1 – 5 calculated using an applicable interest rate.

In months where the combination of lines 1 – 5 for the month produce a debit balance, the generation revenue requirement of non-core DA customers will be decreased by that amount, and the generation revenue requirement of non-core bundled customers will be increased by the same amount.

In months where the combination of lines 1 – 5 for the month produce a credit balance, the generation revenue requirement of non-core DA customers will be increased by that amount, and the generation revenue requirement of non-core bundled customers will be decreased by the same amount.

When the cumulative balance in this subaccount reaches zero, no further entries will be made.

(END OF APPENDIX B)