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Decision 98-09-070 September 17, 1998

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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| Application of Pacific Gas and Electric Company To Identify Cost Savings for Revenue Cycle Services Provided by Other Entities and to Propose Credits for End-Use Customers in Such Circumstances for Implementation No Later Than January 1, 1999. | Application 97-11-004 (Filed November 3, 1997) |
| Application of Southern California Edison Company To Identify Cost Savings for Revenue Cycle Services Provided by Other Entities and to Propose Credits for End-Use Customers in Such Circumstances for Implementation No Later Than January 1, 1999. | Application 97-11-011 (Filed November 3, 1997) |
| Application of San Diego Gas & Electric Company To Identify Cost Savings for Revenue Cycle Services Provided by Other Entities and to Propose Credits for End-Use Customers in Such Circumstances for Implementation No Later Than January 1, 1999. | Application 97-12-012 (Filed December 4, 1997) |

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# OPINION

## I. Summary

This decision resolves outstanding matters in Phase II of the applications of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E) to unbundle portions of metering, billing, and related services, which we have referred to as "revenue cycle services." In this decision, we determine how the Applicants should price their revenue cycle services and resolve other related issues.

## II. Background

The Commission's "Preferred Policy Decision " on electric utility industry restructuring, Decision (D.) 95-12-063, as modified by D.96-01-009, adopted a policy framework that assumes potential energy service providers (ESPs) will enter into competitive electric generation markets only if utility generation is unbundled from transmission and distribution. D.97-05-039 found that specific distribution support functions like metering and billing should also be unbundled in order to promote competition in generation markets or "direct access." We have termed such metering and billing services "revenue cycle services."

D.96-10-074 asked parties to evaluate strategies that would provide opportunities for ESPs to compete in markets for revenue cycle services while protecting the integrity of utility systems and operations. In that regard, we found that parties should have "comparable access to the generation market through metering and billing" and that "such access implies fairness to all stakeholders which avoids cost shifting where, for example, lower costs to one group do not mean stranded costs borne by another." Accordingly, we found that competition in metering and billing is not a goal in itself but a means to achieve effective competition in generation markets.

Subsequently, D.97-05-039 identified specific issues for consideration in this proceeding and D.97-11-073 directed Edison, PG&E, and SDG&E to file applications to accomplish the Commission's unbundling objectives. Accordingly, the utilities filed these applications in November and December 1997. Following a Prehearing Conference (PHC) on January 8, 1998, the assigned commissioners issued a ruling which established a procedural schedule and split the proceeding into two phases. Phase I would consider changes to utility billing systems required to implement billing credits by January 1, 1999. Phase II would resolve "the broader merits of the various proposals to distinguish credits by customer segment and examine competing methodologies for calculating those credits."

On July 2, 1998, we issued D.98-07-032 which resolved issues in Phase I of this proceeding. Specifically, D.98-07-032 addressed (1) the number of credit categories for which the utility billing systems must accommodate, (2) the method by which each category will be segmented, (3) the units in which credits will be shown on the customer bill, (4) the appropriate bill format, and (5) the method for prorating credits. The purpose of Phase I of the proceeding was not to approve final revenue cycle services unbundling, but rather to provide direction to Applicants with regard to how their computer and billing systems should be modified in order to accommodate the final resolution of issues in this proceeding. D.97-07-032 adopted requirements for computer and billing system capabilities that ultimately may not be necessary in order for the utilities to comply with the unbundling requirements we adopt today in Phase II.

The Commission held two PHC's which addressed Phase II issues, both of which were presided over by the assigned ALJ and attended by the assigned Commissioners. The Commission held nine days of evidentiary hearings. It held a closing argument attended by the assigned Commissioners. The parties filed briefs on Phase II issues on June 26, 1998 and reply briefs on July 10, 1998. Parties who filed briefs besides the Applicants were Office of Ratepayer Advocates (ORA), The Utility Reform Network and Utility Consumer Action Network (TURN/UCAN), California Energy Commission (CEC), Enron, California Large Energy Consumers Association and California Manufacturers Association (CLECA/CMA), University of California, the California State University and the California Department of General Services (UC/CSU/DGS), Cellnet Data Systems Inc. (Cellnet), Commonwealth Energy Corporation (Commonwealth), Coalition of California Utility Employees (CCUE), California Competition Network (CCN) and California Farm Bureau Federation (Farm Bureau). Consistent with SB 960, this decision is issued less than 18 months from the dates the applications were filed.

## III. Phase II Issues

### *A.* Policy Considerations

Our policy that Applicants should provide bill credits to customers who no longer subscribe to utility revenue cycle services is founded on our view that competitive offerings of revenue cycle services will facilitate the development of competition in generation markets. The purpose of Phase II is to finalize the type of information the utilities will provide on customer bills and to adopt costing methodologies which would be used as the basis for credits on the bills of customers who choose to subscribe to the revenue cycle services of energy service providers (ESPs, or competitors).

In considering which costing methods should be used to calculate utility billing credits, we are guided by five principles, each of which the parties have addressed either directly or indirectly in testimony and briefs.

Adopted costing methodologies should reflect the costs associated with the revenue cycle service. Consistent with our policies generally, we endeavor to match rates (or in this case, bill credits) to costs so that competitors will offer revenue cycle services to the extent they are able to meet or beat utility costs. In this way, adopted costing methodologies should promote economic efficiency and encourage only those infrastructure investments that are not unnecessarily duplicative. Consistent with the principles of AB 1890 and our policies to promote competition in generation markets, we are mindful that costing methods and ratemaking arrangements must not discriminate between customers who subscribe to the incumbent utility's revenue cycle services and those who subscribe to ESP revenue cycle services.

**Adopted costing methodologies and ratemaking arrangements should not shift costs between customer classes or require the general body of ratepayers to assume new liabilities associated with unbundling revenue cycle services.** Our electric restructuring policy decision, D.95-12-063, determined that industry restructuring should not cause shifts in cost responsibilities between customer groups. We reiterated this principle in D.96-10-074 with regard to revenue cycle services. Public Utilities Code Section 368(b) similarly admonishes against cost shifting. We do not intend that the general body of ratepayers should assume higher cost liability on behalf of customers who subscribe to the revenue cycle services of competitors. This could happen if revenue cycle services credits exceed those costs actually avoidable by the utility. We will not adopt any costing methodology which automatically requires that we shift revenue requirements from direct access customers to bundled customers.

**Adopted costing methodologies and ratemaking arrangements should not require utility shareholders to assume liability for losses associated with unbundling unless they fail to manage their revenue cycle services businesses prudently.** The purpose of unbundling is to provide customers with additional choices, to promote lower prices, and better services. In the pursuit of those objectives we do not intend to shield the incumbent utilities from the risk associated with retaining their customers. Nevertheless, we will not adopt costing methodologies or ratemaking arrangements which do not provide the utilities with an opportunity to recover their reasonable costs. The utilities should be indifferent to the effects of our adopted costing methodologies on their rates of return as long as they conscientiously manage their operations.

**Adopted costing methodologies should be consistent for the three utilities.** The use of a common method will help ensure that customers and ESPs are treated equitably throughout the state and, as UC/CSU/DGS observe, prevent distortions in prices which may create barriers to competition. If we were to adopt different methodologies for the utilities, we might inadvertently penalize one by stifling its ability to compete. As SDG&E and Edison observe, utility credits may differ notwithstanding the use of a common method because the utilities have different business processes and serve different geographic locations.

**Adopted costing methodologies and ratemaking arrangements should avoid complicating regulation.** Some parties have proposed accounting mechanisms to true-up revenues and costs. Some have proposed frequent updates of costs. Our order today avoids to the extent possible the adoption of costing methodologies or ratemaking arrangements that would increase our regulatory oversight of revenue cycle services or complicate ratemaking generally. We do so believing that the costs of more regulatory complexity would not necessarily be offset by the associated benefits. We endeavor here to develop credits which minimize our future intervention.

We do not decide here the extent to which ESPs, revenue cycle services customers, shareholders or utility ratepayers generally should be liable for the costs of implementing revenue cycle services with the exception of certain variable costs the utilities may incur in the future. Edison estimates fixed implementation costs are about $30 million which it seeks to recover in ratemaking proceedings related to PU Code § 376.[1] SDG&E and PG&E did not have comprehensive estimates of implementation costs at the time of hearing but indicated that they may seek recovery of some related costs in PBR or general rate case proceedings. Enron proposes that ratepayers generally should assume the costs of implementing revenue cycle services on the basis that customers will benefit from having the opportunity to choose a competitive service provider, whether or not they actually prefer the services of a competitor. We intend to determine the allocation of implementation costs between various interests in those proceedings in which the utilities seek cost recovery.

## B. Avoided Costs vs. Fully-Allocated Costs

The most contentious issue in Phase II of this proceeding is the method the utilities will use to estimate costs and develop associated credits. Revenue cycle services credits differ depending on which cost method is used. The larger the credit, the more likely an ESP will be able to compete with the utility for revenue cycle services business because the ESP will be more able to set its prices below the level of utility credits. The parties presented two differing methods referred to as "avoided costs" and "fully-allocated costs." Appendix A illustrates these proposals and those adopted by this decision.

Avoided costs. Avoided costs are only those which the utility ceases to incur when a customer stops taking the associated service. "Net" avoided cost calculations presented here remove the additional cost the utility incurs when a competitor offers the revenue cycle service.

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[1] Section 376 provides that the utilities may recover costs incurred and required to implement direct access.

PG&E and Edison propose an avoided cost approach which would incorporate only those costs which are variable in the short-run and which require no redeployment of labor, capital or materials. Costs which are fixed in the short term, even if avoidable in the longer term, are not included. Past liabilities are not included. Accordingly, PG&E and Edison include no costs associated with administrative and general functions, depreciation, and supervision, among other things.

SDG&E also proposed an avoided cost methodology, although its perspective differs from that of Edison and PG&E. SDG&E proposes that the cost model include all variable and fixed costs which may be avoided assuming management acts aggressively to achieve associated savings in the shorter term. SDG&E refers to cost savings which must be pursued by management as "opportunity costs." SDG&E also proposes a way for the resulting credits to account for varying levels of market penetration.

All three utilities estimated their avoided costs by conducting studies of their activities and how those activities would change in cases where customers subscribed to competitors' revenue cycle services. In advocating the use of avoided cost models, Applicants urge the Commission to reject costing methods which include overhead, A&G and other common costs in revenue cycle services credits. They argue that these costs do not vary with low levels of market penetration in revenue cycle services and that they will incur such costs notwithstanding the success of ESPs in offering revenue cycle services to customers. SDG&E notes that it included some common costs in its model to the extent those costs could be avoided or deployed in some other line of business.

TURN/UCAN, ORA, CCUE and other parties support SDG&E's avoided cost model generally. TURN/UCAN nevertheless takes exception to several aspects of SDG&E's study, believing that the cost studies of all Applicants are "self-serving" and designed to stifle competition by understating the costs they may avoid. CLECA/CMA also supports avoided cost methods, but believes the utilities' studies do not in all cases accurately reflect savings. CCUE supports Applicants' avoided cost proposals.

**Fully-Allocated Costs.** Fully-allocated costs as they have been addressed in this proceeding include all fixed and variable costs associated with the service. Such costs include depreciation, capital costs and other costs which are "sunk" and therefore not avoidable under any circumstance. Fully-allocated costs also includes indirect costs such as pensions and benefits, supervisory costs and common plant costs.

Enron and Cellnet propose establishing revenue cycle services credits which are based on fully-allocated costs. They observe such costs are readily identified because they are currently reflected in rates and in FERC and Commission accounts. Accordingly, they may be audited and provide historic information. Enron and Cellnet believe fully-allocated costs must be included in the bill credits in order to provide realistic price signals to customers. Cellnet argues the Applicants have failed to demonstrate that they will be unable to recover fully-allocated costs from their customers if the costs are reflected in the bill credits. Cellnet and Enron argue that unless the Commission adopts a fully-allocated cost allocation method, the utilities will receive money from direct access customers through distribution rates for services the utilities do not provide.

UC/CSU/DGS support fully-allocated costing methods as the best way to assure customers do not pay for costs they do not incur. UC/CSU/DGS believes FERC accounting data is a reasonable proxy for actual cost data. UC/CSU/DGS comments that SDG&E's avoided cost method provides a second best approach to revenue cycle services costing. Commonwealth and CCN filed briefs in support of Enron's cost studies, believing fully-allocated cost methods will promote optimal levels of competition.

Discussion. The process of establishing pricing policies as part of an effort to unbundle utility services and thereby promote competition is not a new exercise. We have addressed it for many utility services over the years. Here, as in previous cases, we must balance competing objectives to promote competition, provide the utilities with a reasonable opportunity to recover costs and protect customers from unfair pricing.

The choice of costing methodology will influence the extent to which utility competitors are successful in revenue cycle services markets. The use of an avoided cost approach results in billing credits which are in some cases substantially lower than those which result from the use of a fully-allocated cost method. In either case, competitors will have to offer services at prices that are equal to or lower than the utility credit. Understandably then, Enron and Cellnet support costing methods which yield higher credits. The utilities support costing methods which yield lower credits and would limit their risk of cost recovery and prospects for successful competition. Consumers are not indifferent. If we require the utilities to set prices that are higher than economic costs, consumers may face prices which permit providers of revenue cycle services to realize extraordinary profits. If we set prices that are lower than economic costs, consumers may not have the opportunity to take advantage of the offerings of competitors.[2]

In D.97-05-039, the Commission stated its intent to develop utility revenue cycle services credits based on cost savings "resulting when billing,

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[2] During the rate freeze period imposed by AB 1890, consumers will pay the same total rate for bundled services.

metering and related services are provided by another entity." Subsequently, in D.98-02-111, the Commission stated that "customers who receive revenue cycle services through a third party should be credited by the utility distribution company with the net avoided costs that result. The purpose of this proceeding, by contrast, is to implement that policy, for each of the three utility distribution companies." These statements express an intent to establish revenue cycle services credits that reflect savings which actually occur when utility competitors provide revenue cycle services to energy customers. Fully-allocated cost methodologies, as Enron has defined them, include costs which cannot be avoided, at least not in the short term or at market penetration levels which may be reasonably anticipated at this time. For example, Enron proposes that revenue cycle services credits reflect depreciation and other capital costs that are "sunk." These costs do not fall when the utility stops offering service to a customer; the utility must still recover them or assume an associated loss. Enron proposes to include the proportional cost of overheads in revenue cycle services credits. Among those overhead costs are obligations that are fixed notwithstanding the provision of service to an individual customer.

We agree with Edison's observation that a fully-allocated cost method assumes inappropriately that all costs are variable, even at low levels of penetration. In the case of revenue cycle services, costs associated with certain operations, in fact, are fixed and therefore, not avoidable at low penetration levels. Such costs could, however, become variable with greater penetration levels or over longer periods of time. For example, the cost of operating a general office do not vary at low levels of penetration. When the utility stops providing a revenue cycle service to a single customer in a residential neighborhood, the utility does not avoid its general office expenses. As ORA points out, circumstances could develop in the future to make additional common costs avoidable, but they will not be avoidable in 1999.

Cellnet argues that applying avoided cost methodologies will permit the utilities to recover fixed and overhead costs twice because they will be able to collect them from distribution customers and avoid the costs altogether. We disagree. To the extent costs are avoidable, they should be included in avoided cost calculations.

We agree with Enron and Cellnet that competitive firms, like utilities, incur fixed costs and must recover them in the long run. To the extent we wish to recognize the pricing mechanisms of a competitive market, therefore, we should include fixed costs in rates, at least over the longer term. In revenue cycle services markets, however, we are not convinced that prices must be set at fully-allocated costs in order to assure market entry by competitors. This is because ESPs are likely to be able to recover their fixed costs in related markets. Accordingly, such firms may be able to recover fixed and overhead costs in the prices for those related products, which is to say they may realize economies of scope in their offering of revenue cycle services. They will thereby be able to compete by pricing their own revenue cycle services based on avoided costs (or short run marginal costs). This assumption is fully consistent with our finding in D.96-10-074 that competition in revenue cycle services markets is a worthwhile pursuit mainly as a way of facilitating direct access in generation markets.

In any event, at this juncture, our goal is not to promote competition without regard for other policy objectives. Rather, our goal is to permit the provision of revenue cycle services by competitors without shifting costs to remaining customers or shareholders. Under the circumstances, we adopt a model applying short-run avoided costs which we believe represents a conservative approach to pricing revenue cycle services.

In the future, we may take a different approach. In recognition that market prices are generally considered to be based on long-run marginal costs, we believe the costing method we adopt today will require modification if competition is to develop over the longer term. We are currently constrained in our ratemaking approaches pursuant to cost shifting and rate freeze provisions of AB 1890 in effect during the transition period. During the post-transition period, however, such constraints fall away. Accordingly, we herein direct Applicants to include in their January 15, 1999 applications for post-transition period ratemaking proposals for more complete revenue cycle services unbundling at rates which approximate those likely to prevail in a sustainable competitive market, specifically, those set at long-run marginal costs or some variation which includes all costs which would be incurred over the long-run to provide the service.

In the meantime, we reject fully-allocated cost methodologies and instead adopt a version of avoided costs for establishing revenue cycle services credits. Having determined that an avoided cost approach is generally appropriate, we must still resolve a number of outstanding disputes with regard to which costs we should assume the utilities may avoid.

### 1. SDG&E's Methodology

As described earlier, SDG&E presented an avoided cost methodology which differs from those of PG&E and Edison in certain aspects. The most significant of these is SDG&E's assumption that some share of labor costs are avoidable at all levels of market penetration. The assumption rests on a view that management should be prepared to change business practices in ways which re-deploy labor. Edison opposes the assumption on the basis that SDG&E has provided no evidence to demonstrate the flexibility of labor resources at low levels of market penetration, believing that changes in business practices will involve additional costs which would swamp any associated savings. PG&E and Edison assume that no overhead costs are avoidable.

In calculating avoidable costs, SDG&E assumes 100% market penetration and then adjusts the credit to account for lower estimated levels of market penetration. Edison and PG&E assumed less than 10% penetration, an assumption which TURN/UCAN believes is a "self-fulfilling prophecy" because the resulting credit would dampen competition.

We adopt the avoided cost method SDG&E presented here. We find that it recognizes the cost savings a utility may and should avoid with conscientious management, a feature which reflects the behavior of successful firms subject to market discipline. The method also recognizes the effects of changing levels of market penetration which we are convinced affect the savings the utility may achieve. We adopt the method for all three utilities because it is well-supported and conceptually sound. Applying it only to SDG&E would penalize SDG&E for presenting an approach that is most responsive to the Commission's objective of promoting competition in revenue cycle services markets. We note that, although we adopt SDG&E's methodology, the resulting credits for each Applicant will differ according to their own costs and circumstances. Our adopted credits are set forth in Appendix A.

We elaborate below on specific related issues, some of which are not directly related to SDG&E's costing approach or which address modifications to SDG&E's approach proposed by other parties.

### 2. Billing Offsets to Credits to Account for Implementation Costs

PG&E and Edison propose to offset their billing credit estimates of avoided costs by amounts associated with the incremental costs of unbundling revenue cycle services. SDG&E did not include these billing implementation costs from its estimates because, as it states, it currently does not have relevant costing information. SDG&E proposes to consider this matter in the utilities' § 376 filings.

Enron opposes offsetting the bill credits by the incremental costs of unbundling revenue cycle services. It argues that doing so creates incorrect price signals. It is also concerned that the utilities are seeking recovery of such costs in other proceedings.

Ordering Paragraph 5 of D.97-05-039 directed the utilities to file these applications in order to explore "the net cost savings resulting when billing, metering, and related services are provided by another entity." The use of the term "net" in this context can only mean those cost savings which result after other costs have been removed from the calculation. We do not share Enron's concerns that offsets to credits which reflect the costs of unbundling will compromise the creation of appropriate price signals. To the contrary, such costs must be reflected in rates (or service fees to ESPs) in order for the rates to reflect the true cost to society of the unbundled offering. This is consistent with Enron's position that all other utility costs should be reflected in rates or credits. In fact, we are concerned with the notion that the general body of ratepayers should assume the costs of modifying the infrastructure to unbundle revenue cycle services, as Edison and PG&E are apparently proposing in their § 376 applications and elsewhere. Notwithstanding our concern, we leave that matter to other proceedings.

Enron is correct, however, that costs recovered pursuant to our order today should not be recovered twice, in other rates as the result of action in other forums. To the extent the utilities seek funding in other proceedings, we expect them to explain how revenue cycle services costs for which they seek recovery are or are not already recovered in other fees or rates.

If they do not meet this burden, we will consider the costs to be unreasonable for ratemaking purposes.

We do not adopt the billing offsets proposed by Edison and PG&E although they may reasonably reflect the incremental costs of unbundling revenue cycle services. Instead, we will allow the UDCs to recover these costs in service charges to ESPs. PG&E, Edison, and SDG&E should file an advice letter within 20 days of the effective date of this order setting forth the level of service fees for a partial (and full) consolidated ESP billing. In the advice letter filing, utilities must clearly present the menu of service fees for partial and full consolidated billing services to ensure that ESP's undertaking full consolidated billing are not being charged for services not received. Because we do not adopt specific fees in this decision, Energy Division is directed to conduct a workshop after the service fee advice letters are submitted in order to discuss the proposed fees. Based on that workshop, Energy Division should prepare a resolution regarding which fees and associated charges are reasonable. We state here that we do not intend to allocate these to the general body of ratepayers as a matter of fairness and consistent with sound pricing principles.

### 3. Working Cash

Enron and TURN/UCAN propose that revenue cycle services credits reflect improved working cash for the utilities. Enron assumes working cash will improve because the utilities will receive cash as security deposits from ESPs offering revenue cycle services. As Edison and SDG&E observe, however, ESPs need not (and apparently have not thus far) provided cash deposits to the utilities, instead opting to provide non-cash securities. Even if an ESP did provide a cash deposit, the utility would be required to provide interest on the deposit, offsetting any potential benefit to working cash. Working cash effects will not be included in the RCS credit calculation.

### 4. Uncollectibles

TURN/UCAN argue that although the utilities' uncollectibles risk may not change, the revenue impact will. TURN/UCAN provide an example to show that when a customer who is a poor credit risk is returned to the utility from the ESP for nonpayment, the ESP will have assumed the loss already.

We agree with Applicants that uncollectibles rates are not likely to improve markedly because ESPs are not likely to market their revenue cycle services to a broad cross-section of utility customers, but instead to larger and more creditworthy customers. Nevertheless, the utilities are likely to see some improvements in their uncollectibles rates. SDG&E's uncollectibles calculation includes an estimate of the uncollectibles benefit in the revenue cycle services credits. While it may err on the side of being too high, as Edison observes, SDG&E's assumption is superior to an assumption that no cost savings will occur, as PG&E and Edison propose. We adopt SDG&E's methods for calculating avoidable costs for uncollectibles for all three Applicants in all relevant categories.

### 5. Segmenting Customer Groups By Rate Schedule

Applicants segmented customers according to rate schedules for meter services, meter reading, and meter ownership. For billing and payments credits, Edison segmented customers according to size. PG&E segmented customers by rate schedule. SDG&E segmented customers according to whether they are residential or nonresidential. No party objected to these proposals which were originally presented in Phase I of this proceeding. We adopt them here.

### 6. Full and Partial ESP Consolidated Billing

As stated earlier, we adopt SDG&E's method for valuing each revenue cycle services credit. However, at this time, we only adopt the credits for partial consolidated billing. We direct the utilities to use the credits of partial consolidated billing for full consolidated billing services. This means the credits should assume some savings in labor and supervisor costs and uncollectibles costs. Each utility may recover for ongoing unbundling costs by way of service fees to be developed by way of advice letter, as we have stated.

### 7. Meter Ownership Credits

For customers who purchase their own meters, SDG&E proposes to value existing meters which may be reused based on "replacement cost new less depreciation" (RCNLD). Edison and PG&E use the same basis for their calculations except that they subtract the cost of restocking the meter, attributing little or no salvage value to the meter. ORA and SDG&E believe this adjustment is appropriately a cost associated with industry restructuring. TURN/UCAN also believe Edison and PG&E undervalue existing meters. The CEC and SDG&E take issue with the factor that PG&E and SCE apply to the RCNLD meter value to reflect an assumption that returned meters will outnumber new meter installation. We concur with the parties' observations that Edison and PG&E undervalued existing meters and inappropriately assume that reusable meters will have to be discarded even at market penetration less than 10%. We adopt SDG&E's method for valuing meters.

Enron proposes this credit be based on the net book value of Edison's meters, a method which Applicants argue overstates the value of the meter because installation costs, which are sunk and therefore not avoidable, are included in the book value of the meter. Enron's proposed meter ownership credit assumes costs related to installation which are not avoided when a customer stops subscribing to the utility service. Consistent with our views regarding SDG&E's methodology generally and our finding that only avoidable costs should be included in revenue cycle services credits, we apply SDG&E's method for calculating meter ownership credits to all three Applicants. We note that this method does not distinguish between the circumstance where the customer purchases the meter in an existing location or a new location, a matter which we address more fully in a subsequent section on new meter installations.

### 8. Meter Reading Supervision Costs as Semi-variable

SDG&E treats supervision costs as "semi-variable" rather than "variable" because it assumes that one of its ten supervisor's time is not avoidable until 10% market penetration is achieved. ORA notes that SDG&E's assumption that the market penetration level is 10% before one supervisor can be redeployed for other activities implies that all ten of its supervisors are now fully occupied. The presumption is that any growth in the number of customers in its service area would require the addition of an eleventh supervisor. SDG&E did not demonstrate that this is the case. Nor did SDG&E demonstrate that as a supervisor's time is reduced below full-time, redeployment of its fractional workload to other activities could not occur. ORA also notes that if a utility that is larger than SDG&E employs more than ten meter-reading supervisors, redeployment of a supervisor could occur at a lower market penetration level than the 10% used by SDG&E. Therefore, ORA recommends treating meter-reading supervision time as a variable cost, which recommendation SDG&E does not dispute in principle. We agree with the principle that the utilities should creatively manage their business practices to reduce costs. We adopt SDG&E's semi-variable assumption for supervisory costs since penetration levels are below 10%. However, with higher market penetration levels, we will treat supervisory costs as variable so that the credits reflect all avoidable costs and will expect credit updates to reflect this assumption.

#### 9. Market Penetration Assumptions

SDG&E proposes that credits vary incrementally according to penetration levels. SDG&E shows credit levels for every 10% increment of penetration between 10% and 100%. Accordingly, it recommends that each utility update its credits when the penetration levels exceed 10%. In the first year, SDG&E recommends that the Commission require the utilities to assume that penetration is random, that is, that ESPs will not target or acquire certain subsets of customers.

We direct the utilities to update their credits when RCS penetration levels exceed the 10% threshold. Until that time or until a CPUC decision modifies the credit method altogether, the credits shown in Appendix A will be in effect.

### C. Updates to Adopted Credits

Most parties generally agree that the credits adopted here should be updated annually. ORA recommends the methodology and the numbers should be reviewed annually. SDG&E, Enron, and PG&E agree that the methodology should remain intact but that the numbers be adjusted to reflect changes in revenue cycle services market penetration. Unlike the other parties, Cellnet suggests the credits remain unchanged through the transition period so that ESPs may rely on those credits in determining the wisdom of investments in their own billing and metering systems. UC/CSU/DGS cautions that too many rate changes may contribute to customer confusion.

We do not intend to revisit the methodology adopted here in the near future. While the parties may dispute its relevance, it is fair and recognizes all avoidable costs in the near to medium term. Accordingly, we intend to retain the method through the transition period. We will, however, make adjustments to the rates to reflect market penetration adjustments when they exceed 10% and include the significant changes in net cost assumptions that we have cited elsewhere in this decision. In response to Cellnet's concern that we retain the credits through the transition period, we comment that Cellnet seeks market price stability that does not exist in competitive markets. We are not convinced that we should keep revenue cycle services credits artificially stable for the purpose of reducing ESPs' investment risks. We will conduct such a review annually as the parties suggest and herein direct the utilities to file updates in their respective Revenue Adjustment Proceedings beginning in 1999.

### D. Ratemaking Effects

The unbundling of revenue cycle services has implications for ratemaking accounting during the transition period. PG&E proposes that in order to assure it does not unjustly recover the amounts it offers in revenue cycle services credits, its Transition Revenue Account (TRA) be modified to provide for "a credit entry equal to the recorded amount of revenue cycle services credits given to customers for revenue cycle services provided by entities other than PG&E." This is consistent with our view of the purpose of the TRA and the revenue cycle services credits. All three Applicants should modify their accounting to accomplish the type of offset PG&E proposes during the transition period, consistent with the mechanisms we have adopted for each in the streamlining orders and subsequent resolutions.

## IV. Issues Identified in D.98-07-032 for Final Resolution in Phase II

D.98-07-032 tentatively resolved several issues for final resolution here, discussed below.

### A. New Meter Installations

ORA, TURN/UCAN and Enron propose that the utilities segment the meter ownership credit for new installations where a utility meter is never installed. TURN/UCAN observes that the practice of automatically providing a meter as part of the service extension is anti-competitive and harmful to direct access. Currently, the meter does not permit time-of-use calculations, is not charged to the customer and is included in the utility's ratebase. According to TURN/UCAN,ORA, and Enron, this regulatory convention discourages customers from purchasing their own meters, from installing meters which are compatible with direct access, and creates a disadvantage to utility competitors. TURN/UCAN recommends that customers of new installations be required to choose their meters and to pay for the cost of that meter directly to the provider. TURN/UCAN observes that the result will be to reduce regulated ratebase and to eliminate prospects for stranded investments in utility meters. TURN/UCAN recommends that the implementation of changes to the rules for new installations and related changes to line extension allowances be accomplished by way of the "flow-through" mechanism adopted in D.97-12-098 in the line extension proceeding. TURN/UCAN believes this mechanism anticipated exactly the type of regulatory change it recommends here. More specifically, TURN/UCAN recommends the Commission find that the revenues associated with the newly-competitive revenue cycle services do not support line and service extensions. UC/CSU/DGS concur with TURN/UCAN on this issue.

PG&E replies that the Commission does not have a record here to adopt a credit for new installations. It also believes the issues are more appropriately addressed in the line extension proceeding where we have considered the amounts developers should receive for installing their own meters. SDG&E believes that meter installation costs are not related to the costing issues identified for resolution in this proceeding, observing that all new construction customers are affected by meter costs regardless of whether they subsequently choose the utility or an ESP to provide the meter. Edison observes that some of TURN/UCAN's related proposals raise issues that are not adequately addressed in the record.

The existing practice whereby the utility credits developers for a share of their costs for new installations or provides a standard meter at no cost which is then rate based is potentially anti-competitive for the reasons TURN/UCAN cites. TURN/UCAN has made a compelling case in favor of changing existing practices from a policy standpoint. The implications of TURN/UCAN's proposals, however, are too complicated to resolve with the record before us. Consistent with the scoping memo in this proceeding, we will not "change such things as the way that the applicants charge for providing and installing meters." We will, however, take the opportunity to state our intent to review existing practice in the near future. We will direct Applicants to propose in the line extension proceeding (R.92-03-050) changes to the line extension rules and related ratemaking arrangements to eliminate any competitive advantage provided to incumbent utilities. In addition, Applicants should propose changes to the calculation of "net revenues" as that term is used to calculate line and service extension allowances so that those net revenues do not include revenues associated with unbundled revenue cycle services.

### B. Gas Meter Reading Credits

In D.98-07-032, we left open the question of whether the Applicants should create a credit for circumstances in which the ESP would read the gas meters of dual commodity utilities (PG&E and SDG&E). The parties were divided on the wisdom of creating a credit here while the Commission considered the broader issues in its natural gas rulemaking, R.98-01-011. We find that it would be premature to order a credit at this time and defer to the matter in R.98-01-011.

### C. De-Averaging Credits by Geographic Areas

Applicants propose de-averaging revenue cycle services credits according to geographic areas. They observe de-averaging will recognize that different customers impose different costs on the system. They also believe that failure to undertake some de-averaging will permit competitors to "cream-skim" by soliciting business from customers who cost the least to serve but whose credits do not recognize these lower costs. CCUE supports geographic de-averaging.

Enron objects to geographic de-averaging, mainly on the basis that underlying rates are set based on averages. As a result, de-averaging will, according to Enron, require that the utility charge an average rate for its own bundled customers and a de-averaged rate for unbundled customers. Enron argues the result is contrary to AB 1890 which requires that direct access customers pay the same as bundled customers for utility service. Enron is concerned that ESPs would be saddled with the burden of calculating as many as five different rates for their customers while the utilities need only calculate one.

TURN/UCAN also argue that the Commission should not adopt de-averaging proposals, believing the utilities have failed to support them. TURN/UCAN cites previous Commission decisions rejecting rate de-averaging proposals in favor of a more cautious approach. Farm Bureau and CCN join in opposition to geographic de-averaging for similar reasons. While not objecting to de-averaging on a conceptual basis, UC/CSU/DGS also believe the Applicants' proposals are weak.

The utility proposals for geographic de-averaging more accurately reflect costs than averaged credits or rates and would accordingly promote economic efficiency for that portion of rates subject to de-averaging. De-averaged rates would discourage competitors from focusing their market efforts on customers whose rates are set substantially above costs. In these ways, de-averaged rates are consistent with our economic policies generally. Nevertheless, we are concerned that de-averaging a portion of the utility's rates in a piecemeal fashion could undermine any gains in economic efficiency. In this case, high cost customers would receive larger credits, thereby effectively reducing their distribution rate to a level below that of a customer who is less expensive to serve. Therefore, although de-averaging revenue cycle services provides more accurate prices, it concurrently creates the opposite effect with respect to distribution rates. At this time, therefore, we reject utility proposals to de-average.

For periods in the post-transition period, we intend to adopt some form of geographic deaveraging which does not present the anomalies which would result from deaveraging revenue cycle services in isolation and during this period when our ratemaking authority is so circumscribed. We therefore, direct the Applicants to propose geographic deaveraging for revenue cycle services and other distribution services in their January 15, 1999 applications for ratemaking in the post-transition period.

## V. Conclusion

We herein adopt a costing model for each of the Applicants which is generally based on the methodology proposed by SDG&E in this proceeding. The resulting revenue cycle services credits for PG&E and the rate schedule mappings for SDG&E and SCE are presented in Appendix B. The adopted billing credits exclude the cost offsets proposed by PG&E and Edison for each category and modify the assumptions of Edison and PG&E as set forth in earlier portions of this decision. We also reject proposals for geographic rate de-averaging of meter reading credits at this time.

We recognize that the adopted costing principles and credits are not perfect. We approximate prices that might otherwise be set in a competitive market using analytical tools which are at best imprecise and which fail to recognize the dynamic and unpredictable nature of unregulated markets. Nevertheless, we believe the credits we adopt today reasonably reflect the utilities' costs and will serve as adequate price signals in revenue cycle services markets for the foreseeable future with the applicable adjustments to recognize changes in market penetration. We have also stated our intent to modify these pricing methods for the period following the rate freeze and will proceed to consider such modifications in 1999.

## Findings of Fact

1. D.97-05-039 and D.98-02-111 stated an intent to develop costing methods for revenue cycle services which reflect costs which are actually avoided or avoidable by the utility.

2. Fully-allocated costing methods, as proposed herein, would require cost shifting to the general body of ratepayers or losses by utility shareholders.

3. Revenue cycle services exhibit economies of scope which suggests providers of such services may recover fixed costs by way of prices for related services.

4. SDG&E's avoided cost methodology recognizes opportunities for utilities to avoid certain types of labor costs, reflecting the behavior of successful firms subject to market discipline. As market penetration increases, supervisory costs fall.

5. The billing offsets to revenue cycle services credits proposed by Edison and PG&E may reasonably estimate the incremental cost to the utility of providing the revenue cycle services.

6. The Applicants are likely to see some improvements in uncollectibles rates and working cash balances when customers migrate to the revenue cycle services of ESPs.

7. Existing meters have some salvage value.

8. PG&E's proposal for recognizing the accounting effects of revenue cycle services credits during the transition period is consistent with our past decisions regarding ratemaking during the transition period.

9. Existing line extension rules is the appropriate forum for reviewing the regulatory and ratemaking treatment of meter installations at new locations.

10. The record in this proceeding does not provide enough information to resolve issues relating to how to change existing line extension rules affecting competitive markets and how changes should be implemented.

11. It is premature to order the utilities to create revenue cycle services credits for gas meter reading, a matter which is under consideration in R.98-01-011.

12. Geographic de-averaging of revenue cycle services credits generally reflects the costs of serving customers according to the characteristics of their location and thereby discourages ESPs from marketing to customers whose revenue cycle services are higher than costs. When overlying rates are based on average costs, however, the effect of de-averaging revenue cycle services credits is to create greater discrepancies between the rate for distribution service and the cost to provide it. Ratemaking mechanisms to compensate for this would be unreasonably cumbersome.

## Conclusions of Law

1. The Commission should order the applicants to implement the revenue cycle services credits using SDG&E's methodology for the reasons set forth herein.

2. In their tariff filings, the Applicants should present updated revenue cycle services credits when penetration rates exceed the 10% estimate.

3. The Commission rejects Applicants' proposals for geographic de-averaging of meter reading credits.

4. During the transition period, each utility should account for the ratemaking effects of revenue cycle services credits by increasing the amounts available for the Competition Transition Charge (CTC) consistent with Commission orders and resolutions addressing ratemaking during the transition period, as proposed by PG&E.

5. The Commission should direct each Applicant to propose in R.92-03-050 changes to line extension rules and related ratemaking which would eliminate any competitive advantage the utility may have under existing rules in markets for new meter installations, and which would remove revenues associated with unbundled revenue cycle services from the "net revenues" used to calculate line and service extension allowances. The proposed changes should (1) exclude the meter costs and associated revenues from the calculation of the allowance and (2) demonstrate how the utility would remove RCS-related revenues from the distribution revenues currently used to calculate the extension allowance, prior to dividing the "net revenues" by the cost of service factor.

6. With the exceptions set forth herein, the Commission should affirm and formally adopt the findings of D.98-07-032 with regard to billing system modifications required to implement the provisions of this order.

# ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E) shall file tariffs within 20 days of the effective date of this order which implement the credits adopted in Appendix A of this order.

2. PG&E, Edison, and SDG&E shall file advice letters within 20 days to implement service fees for billing services. Energy Division shall conduct a workshop and prepare a resolution for Commission consideration addressing these service fees.

3. Except as set forth in this decision, the provisions for unbundling revenue cycle services adopted conditionally in Decision 98-07-032 are adopted.

4. PG&E, Edison, and SDG&E shall credit their respective accounting mechanisms in place during the transition period to reflect the effects of revenue cycle services credits, consistent with Commission orders and resolutions guiding ratemaking and accounting during the transition period identified in provisions of AB 1890.

5. If the market penetration for any revenue cycle service exceeds 10%, or any increment of 10% thereafter, the utility shall, in its subsequent Revenue Allocation Proceeding application, shall propose changes to that revenue cycle service credit which reflects changes in market penetration and costs, as set forth herein.

6. No later than December 1, 1998, PG&E, Edison, and SDG&E shall file in R.92-03-050, proposed changes to line extension rules consistent with this decision.

7. PG&E, Edison, and SDG&E shall include in their January 15, 1999 applications for ratemaking during the post-transition period proposals (1) to

## Conclusions of Law

1. The Commission should order the applicants to implement the revenue cycle services credits using SDG&E's methodology for the reasons set forth herein.

2. In their tariff filings, the Applicants should present updated revenue cycle services credits when penetration rates exceed the 10% estimate.

3. The Commission rejects Applicants' proposals for geographic de-averaging of meter reading credits.

4. During the transition period, each utility should account for the ratemaking effects of revenue cycle services credits by increasing the amounts available for the Competition Transition Charge (CTC) consistent with Commission orders and resolutions addressing ratemaking during the transition period, as proposed by PG&E.

5. The Commission should direct each Applicant to propose in R.92-03-050 changes to line extension rules and related ratemaking which would eliminate any competitive advantage the utility may have under existing rules in markets for new meter installations, and which would remove revenues associated with unbundled revenue cycle services from the "net revenues" used to calculate line and service extension allowances. The proposed changes should (1) exclude the meter costs and associated revenues from the calculation of the allowance and (2) demonstrate how the utility would remove RCS-related revenues from the distribution revenues currently used to calculate the extension allowance, prior to dividing the "net revenues" by the cost of service factor.

6. With the exceptions set forth herein, the Commission should affirm and formally adopt the findings of D.98-07-032 with regard to billing system modifications required to implement the provisions of this order.

unbundle revenue cycle services and price them at long-run marginal costs or some reasonable proxy, and (2) to undertake geographic deaveraging of revenue cycle services and other distribution services, as set forth in this decision.

8. These consolidated proceedings are closed.

This order is effective today.

Dated September 17, 1998, at San Francisco, California.

RICHARD A. BILAS
President
P. GREGORY CONLON
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
Commissioners

APPENDIX A

| CREDIT CATEGORY | PG&E adopted | PG&E proposal | PG&E by CRA | PG&E by enron | SCE adopted | SCE proposal | SCE by CRA | SCE by enron | SDG&E adopted | SDG&E proposal | SDG&E by CRA | SDG&E by enron |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Billing Services (partial ESP cons.)** | | | | | | | | | | | | |
| ***residential*** | | | | | | | | | | | | |
| electric only customer | $ 0.83 | $ 0.31 | 0.45-1.40 | $ 1.92 | $ 1.40 | $ 0.35 | 0.54-1.40 | $ 1.87 | $ 1.41 | $ 1.41 | $ 1.40 | $ 1.83 |
| combined customer | | ######## | | | | ######## | | | | ######## | $ 0.18 | |
| ESP sends electric but not gas bill | $ 0.05 | $ - | $ 0.18 | $ 1.05 | | N/A | | | $ 0.18 | $ 0.18 | | $ 0.95 |
| ***commercial*** | | | | | | | | | | | | |
| **< 20 kW** | | | | | | | | | | | | |
| electric only customer | $ 1.23 | $ 0.37 | 0.51-1.59 | $ 3.28 | $ 1.40 | $ 0.35 | 0.54-1.59 | $ 1.87 | $ 1.58 | $ 1.58 | $ 1.59 | $ 3.43 |
| combined customer | | ######## | | | | ######## | | | | ######## | $ 0.18 | |
| ESP sends electric but not gas bill | $ 0.14 | $ - | $ 0.18 | $ 1.95 | | N/A | | | $ 0.18 | $ 0.18 | | $ 1.81 |
| **20-500 kW** | | | | | | | | | | | | |
| electric only customer | $ 1.34 | $ 0.37 | 0.50-1.59 | $ 3.29 | $ 2.11 | $ 0.64 | 0.84-1.59 | $ 4.74 | $ 1.58 | $ 1.58 | $ 1.59 | $ 3.43 |
| combined customer | | ######## | | | | ######## | | | | ######## | $ 0.18 | |
| ESP sends electric but not gas bill | $ 0.25 | $ - | $ 0.18 | $ 1.95 | | N/A | | | $ 0.18 | $ 0.18 | | $ 1.81 |
| ***industrial*** | | | | | | | | | | | | |
| **> 500 kW** | | | | | | | | | | | | |
| electric only customer | $ 27.57 | $ 0.37 | 0.50-1.59 | $ 480.29 | $ 13.57 | $ 7.89 | $ 8.08 | $ 172.45 | $ 1.58 | $ 1.58 | $ 1.59 | $ 3.43 |
| combined customer | | ######## | | | | ######## | | | | ######## | $ 0.18 | |
| ESP sends electric but not gas bill | $ 25.51 | $ - | $ 0.18 | $ 272.66 | | N/A | | | $ 0.18 | $ 0.18 | | $ 1.81 |
| **Billing Services (full consol. ESP)** | | | | | | | | | | | | |
| ***residential*** | | | | | | | | | | | | |
| electric only customer | $ 0.83 | $ 0.03 | 0.47-1.51 | $ 2.27 | $ 1.40 | $ (2.73) | 0.72-1.51 | $ 2.18 | $ 1.41 | $ 1.51 | $ 1.51 | $ 1.55 |
| combined customer | $ 0.05 | $ - | $ 0.18 | $ 1.40 | | | | | $ 0.18 | $ 0.28 | $ 0.28 | $ 1.07 |
| ***commercial <20 kW*** | | | | | | | | | | | | |
| electric only customer | $ 1.23 | $ 0.17 | 0.70-3.17 | $ 3.82 | $ 1.40 | $ (2.73) | 0.72-1.51 | $ 2.18 | $ 1.58 | $ 3.15 | $ 3.17 | $ 5.30 |
| combined customer | $ 0.14 | $ - | $ 0.18 | $ 2.49 | | | | | $ 0.18 | $ 1.76 | $ 1.75 | $ 3.68 |
| ***commercial 20-500 kW*** | | | | | | | | | | | | |
| electric only customer | $ 1.34 | $ 0.17 | 0.53-3.17 | $ 3.82 | $ 2.11 | $ (2.01) | 1.44-1.51 | $ 5.39 | $ 1.58 | $ 3.15 | $ 3.17 | $ 5.30 |
| combined customer | $ 0.25 | $ - | $ 0.18 | $ 2.49 | | | | | $ 0.18 | $ 1.76 | $ 1.76 | $ 3.58 |
| ***industrial*** | | | | | | | | | | | | |
| electric only customer | $ 27.75 | $ 0.17 | 0.63-3.17 | $ 564.64 | $ 13.57 | $ 7.81 | $ 11.25 | $ 151.35 | $ 1.58 | $ 3.16 | $ 3.17 | $ 5.30 |
| combined customer | $ 26.51 | $ - | $ 0.18 | $ 355.86 | | | | | $ 0.18 | $ 1.76 | $ 1.75 | $ 3.68 |

Mapping of Customer Group to Representative PG&E Rate Schedule

| Customer Group | PG&E Rate schedule |
|---|---|
| Residential | E-1 |
| Commercial, under 20 kW | A-1 single phase |
| Commercial, 20 - 500 kW | A-6 single phase |
| Industrial, over 500 kW | E-20 firm |

Source:
SDG&E: March 9, 1998; Apr 15 supplemental
SCE: September 1, 1998 update
PG&E Proposal: PG&E Phase 2 Opening Brief, June 26, 1998.
CRA: ORA Phase 2 Opening Brief, June 25, 1998.
Enron: Enron Phase 2 Opening Brief, June 26, 1998.

| CREDIT CATEGORY | PG&E adopted | PG&E proposal | PG&E by ORA | PG&E by enron | SCE adopted | SCE proposal | SCE by ORA | SCE by enron | SDG&E adopted | SDG&E proposal | SDG&E by ORA | SDG&E by enron |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Meter Ownership** | | | | | | | | | | | | |
| *residential* | | | | | | | | | | | | |
| residential, straight register, 1-p | $ 0.09 | $ 0.11 | $ 0.15 | $ 0.31 | $ 0.11 | $ 0.08 | $ 0.12 | $ 0.64 | $ 0.12 | $ 0.13 | $ 0.13 | $ 0.38 |
| residential, TOU | $ 0.57 | $ 1.21 | $ 1.28 | $ 2.23 | $ 2.03 | $ 2.45 | $ 1.64 | $ 7.61 | $ 1.35 | NA | $ 0.38 | $ 0.39 |
| *commercial* | | | | | | | | | | | | |
| < 20 kW, straight register, 1-pha | $ 0.09 | $ 0.11 | $ 0.15 | $ 0.31 | $ 0.11 | $ 0.08 | $ 0.12 | $ 0.64 | $ 1.04 | $ 1.04 | $ 1.04 | $ 1.03 |
| < 500 kW, straight register, 3-ph | $ 0.61 | $ 0.89 | $ 2.78 | $ 2.11 | $ 0.50 | $ 0.45 | $ 0.41 | $ 4.54 | $ 1.25 | $ 1.25 | $ 1.25 | $ 1.24 |
| < 500 kW, TOU/IDR | $ 0.57 | $ 1.21 | $ 2.78 | $ 2.23 | $ 2.03 | $ 2.45 | $ 1.64 | $ 7.61 | $ 0.38 | $ 0.38 | $ 0.38 | $ 0.39 |
| *industrial* | | | | | | | | | | | | |
| > 500 kW (excl non-firm) | $ 1.42 | $ 2.69 | $ 2.78 | $ 4.73 | $ 8.26 | $ 23.05 | $ 6.68 | $ 34.54 | $ 3.40 | $ 3.40 | $ 3.40 | $ 3.41 |
| non-firm | $ 4.57 | $ 6.50 | $ 5.41 | | | | | | | | | |

| CREDIT CATEGORY | PG&E adopted | PG&E proposal | PG&E by ORA | PG&E by enron | SCE adopted | SCE proposal | SCE by ORA | SCE by enron | SDG&E adopted | SDG&E proposal | SDG&E by ORA | SDG&E by enron |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Meter Services** | | | | | | | | | | | | |
| *residential* | | | | | | | | | | | | |
| residential, straight register, 1-p | $ 0.16 | $ 0.13 | $ 0.21 | $ 0.16 | $ 0.01 | $ 0.01 | $ 0.09 | $ 0.12 | $ 0.05 | $ 0.08 | $ 0.08 | $ 0.10 |
| residential, TOU | $ 1.71 | $ 1.54 | $ 1.74 | $ 1.85 | $ 0.85 | $ 0.79 | $ 0.88 | $ 1.11 | $ 0.05 | $ 0.08 | $ 0.08 | $ 0.10 |
| *commercial* | | | | | | | | | | | | |
| < 20 kW, straight register, 1-pha | $ 0.10 | $ 0.09 | $ 0.17 | $ 0.11 | $ 0.01 | $ 0.01 | $ 0.09 | $ 0.12 | $ 0.05 | $ 0.08 | $ 0.08 | $ 0.10 |
| < 500 kW, straight register, 3-ph | $ 0.10 | $ 0.09 | 1.01-1.70 | $ 0.11 | $ 0.07 | $ 0.06 | $ 0.17 | $ 0.21 | $ 0.05 | $ 0.08 | $ 0.08 | $ 0.10 |
| < 500 kW, TOU/IDR | $ 1.56 | $ 1.50 | 1.01-1.70 | $ 1.81 | $ 0.85 | $ 0.79 | $ 0.88 | $ 1.11 | $ 0.05 | $ 0.08 | $ 0.08 | $ 0.10 |
| *industrial* | | | | | | | | | | | | |
| > 500 kW (excl non-firm) | $ 0.90 | $ 0.81 | $ 1.01 | $ 0.97 | $ 3.71 | $ 3.42 | $ 3.43 | $ 4.38 | $ 0.04 | $ 0.155 | $ 0.16 | $ 0.18 |

Mapping of Customer Group to Representative PG&E Rate Schedule

| Customer Group | PG&E Rate schedule |
|---|---|
| Residential, straight register, 1-phase | E-1 |
| Residential, TOU | E-7 |
| Commercial, under 20 kW, straight register, 1 phase | A-1 single phase |
| Commercial, under 500 kW, straight register, 3 phase | A-1 poly phase |
| Commercial, under 500 kW, TOU/IDR | A-6 single phase |
| Industrial, over 500 kW, TOU/IDR | E-20 firm |

Source:
SDG&E: March 9, 1998; Apr 15 supplemental
SCE: September 1, 1998 update
PG&E proposal: PG&E Phase 2 Opening Brief, June 26, 1998.
ORA: ORA Phase 2 Opening Brief, June 26, 1998.
Enron: Enron Phase 2 Opening Brief, June 26, 1998.

| CREDIT CATEGORY | PG&E adopted | PG&E proposal | PG&E by ORA | PG&E by enron | SCE adopted | SCE proposal | SCE by ORA | SCE by enron | SDG&E adopted | SDG&E proposal | SDG&E by ORA | SDG&E by enron |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Meter Reading** | | | | | | | | | | | | |
| ***residential*** | | | | | | | | | | | | |
| electric only customer | | ######## | | | | ######## | | | | ######## | | |
| read SR | $ 0.71 | 0.43-0.81 | 0.47-0.89 | $ 1.13 | 0.65 | 0.19-0.47 | .43-.73 | $ 0.76 | $ 0.47 | 0.45-1.78 | .43-1.12 | $ 0.57 |
| read TOU/DR | $ 0.71 | 0.43-0.81 | 0.54-0.93 | $ 1.13 | $ 1.43 | 0.90-1.18 | 1.66-1.91 | $ 1.64 | $ 0.63 | 0.52-1.94 | .89-1.6 | $ 0.74 |
| combined customer | | ######## | | | | ######## | | | | ######## | | |
| read SR | $ 0.21 | $ 0.19 | $ 0.21 | $ 0.56 | | N/A | | | $ 0.08 | $ 0.08 | $ 0.08 | $ 0.29 |
| read TOU/DR | $ 0.21 | $ 0.19 | $ 0.32 | $ 0.56 | | N/A | | | $ 0.24 | $ 0.24 | $ 0.24 | $ 0.37 |
| ***commercial*** | | | | | | | | | | | | |
| ***under 20 kW*** | | | | | | | | | | | | |
| electric only customer | | ######## | | | | ######## | | | | ######## | | |
| read SR | $ 0.72 | 0.44-0.70 | .47-.76 | $ 1.14 | 0.65 | 0.19-0.47 | .43-.73 | $ 0.76 | $ 0.47 | 0.45-1.78 | .43-1.12 | $ 0.57 |
| read TOU/DR | $ 0.72 | 0.44-0.70 | .57-.82 | $ 1.14 | $ 1.43 | 0.90-1.18 | 1.66-1.91 | $ 1.64 | $ 0.63 | 0.62-1.94 | .83-1.6 | $ 0.74 |
| combined customer | | ######## | | | | ######## | | | | ######## | | |
| read SR | $ 0.22 | $ 0.20 | $ 0.20 | $ 0.57 | | N/A | | | $ 0.08 | $ 0.08 | $ 0.08 | $ 0.29 |
| read TOU/DR | $ 0.22 | $ 0.20 | 0.38 | $ 0.57 | | N/A | | | $ 0.24 | $ 0.24 | $ 0.24 | $ 0.37 |
| ***commercial*** | | | | | | | | | | | | |
| ***20-500 kW*** | | | | | | | | | | | | |
| electric only customer | | ######## | | | | ######## | | | | ######## | | |
| read SR | $ 0.72 | 0.44-0.70 | .47-.76 | $ 1.14 | 0.75 | 0.29-0.55 | .64-.88 | $ 0.86 | $ 0.47 | 0.45-1.78 | .45-1.11 | $ 0.57 |
| read TOU/DR | $ 0.72 | 0.44-0.70 | .57-.82 | $ 1.14 | 1.40 | 0.90-1.18 | 1.66-1.91 | $ 1.64 | $ 0.63 | 0.62-1.94 | .89-1.6 | $ 0.74 |
| combined customer | | ######## | | | | ######## | | | | ######## | | |
| read SR | $ 0.22 | $ 0.20 | $ 0.20 | $ 0.57 | | N/A | | | $ 0.08 | $ 0.08 | $ 0.08 | $ 0.29 |
| read TOU/DR | $ 0.22 | $ 0.20 | $ 0.38 | $ 0.57 | | N/A | | | $ 0.24 | $ 0.24 | $ 0.24 | $ 0.37 |
| ***industrial*** | | | | | | | | | | | | |
| ***> 500 kW*** | | | | | | | | | | | | |
| electric only customer | | | | | | | | | | | | |
| read TOU/DR | $ 2.54 | 2.15-2.71 | 2.35-2.95 | $ 2.58 | 3.43 | 2.90-3.18 | 1.66-1.91 | $ 1.64 | $ 0.63 | 0.62-1.94 | .9-1.6 | $ 0.74 |
| combined customer | | | | | | | | | | | | |
| read TOU/DR | N/A | N/A | | $1.29 | | N/A | | | $ 0.24 | $ 0.24 | $ 0.24 | $ 0.37 |
| | | | | | | | 4.44-4.69 | $ 4.13 | | | | |

Mapping of Customer Group to Representative PG&E Rate Schedule

| Customer Group | PG&E Rate schedule |
|---|---|
| Residential, straight register, still at premises | E-1 |
| Residential, TOU/DR, still at premises | E-7 |
| Commercial, under 20 kW, straight register, still at pr | A-1 single phase |
| Commercial, under 20 kW, TOU/DR, still at premises | A-6 single phase |
| Commercial, 20 - 500 kW, straight register, still at pre | A-1 poly phase |
| Commercial, 20 - 500 kW, TOU/DR, still at premises | A-6 single phase |
| Industrial, over 500 kW, TOU/DR, still at premises | E-20 firm |
| Industrial, over 500 kW, TOU/DR, not at premises | E-20 non-firm |

<u>Source:</u>

SDG&E: March 9, 1998; Apr 15 supplemental
SCE: September 1, 1998 update
PG&E June 26, 1998: PG&E Phase 2 Opening Brief, June 26, 1998.
ORA: ORA Phase 2 Opening Brief, June 26, 1998.
Enron: Enron Phase 2 Opening Brief, June 26, 1998.

(End of Appendix A)

## PG&E's Proposed RCS Credits - ADOPTED

| PG&E | Meter Services | Meter Ownership | Meter Reading | | | | | | Billing and Payments | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Manual | | | | | Teleph/ modem | Partial ESP consolidated billing | | Full ESP consolidated billing | |
| | | | Dual site | Electric-only site | | | | | Dual | Electric -only | Dual | Electric -only |
| *Rate Schedule* | | | Zones 1-3 | Zone 1 | Zone 2 | Zone 3 | Zones 1-3 | Zones 1-3 | | | | |
| | $/meter/month | $/meter/month | $/meter/month | | | | | | $/account/month | | | |
| *E-1* | $0.16 | $0.09 | $0.21 | $0.44 | $0.69 | $1.29 | $0.71 | N/A | $0.05 | $0.83 | $0.05 | $0.83 |
| *E-7* | $1.71 | $0.57 | $0.21 | $0.44 | $0.69 | $1.29 | $0.71 | N/A | $0.08 | $0.86 | $0.08 | $0.86 |
| *E-8* | $0.16 | $0.09 | $0.21 | $0.44 | $0.69 | $1.29 | $0.71 | N/A | $0.13 | $0.92 | $0.13 | $0.92 |
| *A-1 Single phase* | $0.10 | $0.09 | $0.22 | $0.44 | $0.73 | $1.15 | $0.72 | N/A | $0.14 | $1.23 | $0.14 | $1.40 |
| *A-1 Poly phase* | $0.10 | $0.61 | $0.22 | $0.44 | $0.73 | $1.15 | $0.72 | N/A | $0.14 | $1.23 | $0.14 | $1.40 |
| *A-6 Single phase* | $1.66 | $0.57 | $0.22 | $0.44 | $0.73 | $1.15 | $0.72 | N/A | $0.25 | $1.34 | $0.25 | $1.51 |
| *A-6 Poly phase* | $1.66 | $1.33 | $0.22 | $0.44 | $0.73 | $1.15 | $0.72 | N/A | $0.25 | $1.34 | $0.25 | $1.51 |
| *A-10* | $0.90 | $1.42 | $0.22 | $0.44 | $0.73 | $1.15 | $0.72 | N/A | $2.05 | $3.12 | $2.05 | $3.29 |
| *E-19* | $0.90 | $1.42 | $0.00 | $2.29 | $2.61 | $3.35 | $2.64 | N/A | $9.35 | $10.42 | $9.35 | $10.59 |
| *E-20* | $0.90 | $1.42 | $0.00 | $2.29 | $2.61 | $3.35 | $2.64 | N/A | $26.51 | $27.57 | $26.51 | $27.75 |
| *AG-1A* | $0.06 | $0.61 | $0.00 | $1.34 | $1.61 | $2.28 | $1.85 | N/A | $0.11 | $1.17 | $0.11 | $1.34 |
| *AG-1B* | $0.86 | $1.42 | $0.00 | $1.34 | $1.61 | $2.28 | $1.85 | N/A | $0.43 | $1.50 | $0.43 | $1.67 |
| *AG-RA* | $1.62 | $1.33 | $0.00 | $1.34 | $1.61 | $2.28 | $1.85 | N/A | $0.13 | $1.20 | $0.13 | $1.37 |
| *AG-RB* | $0.86 | $1.42 | $0.00 | $1.34 | $1.61 | $2.28 | $1.85 | N/A | $0.32 | $1.39 | $0.32 | $1.56 |
| *AG-VA* | $1.62 | $1.33 | $0.00 | $1.34 | $1.61 | $2.28 | $1.85 | N/A | $0.14 | $1.21 | $0.14 | $1.38 |
| *AG-VB* | $0.86 | $1.42 | $0.00 | $1.34 | $1.61 | $2.28 | $1.85 | N/A | $0.34 | $1.41 | $0.34 | $1.58 |
| *AG-4 (A,B,C)* | $0.86 | $1.42 | $0.00 | $1.34 | $1.61 | $2.28 | $1.85 | N/A | $0.14 | $1.21 | $0.14 | $1.38 |
| *AG-5 (A,B,C)* | $0.86 | $1.42 | $0.00 | $2.57 | $3.00 | $4.25 | $3.66 | N/A | $0.24 | $1.31 | $0.24 | $1.48 |
| *E-19 (Nonfirm)* | $11.18 | $4.57 | N/A | N/A | N/A | N/A | N/A | $35.95 | $12.47 | $13.53 | $12.47 | $13.70 |
| *E-20 (Nonfirm)* | $11.12 | $4.57 | N/A | N/A | N/A | N/A | N/A | $35.95 | $37.53 | $38.60 | $37.53 | $38.77 |
| *LS1* | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | $0.12 | $1.19 | $0.12 | $1.36 |
| *LS2* | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | $0.12 | $1.19 | $0.12 | $1.36 |
| *LS3* | $0.10 | $0.09 | $0.21 | $0.40 | $0.65 | $1.24 | $0.67 | N/A | $0.12 | $1.19 | $0.12 | $1.36 |
| *OL1* | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | $0.12 | $1.19 | $0.12 | $1.36 |
| *TC1* | $0.10 | $0.09 | $0.21 | $0.40 | $0.65 | $1.24 | $0.67 | N/A | $0.12 | $1.19 | $0.12 | $1.36 |

# Mapping of Customer Segments to Rate Schedules for SDG&E

| Rate Schedule | Kw | Meter Reading | Meter Services | | Meter Ownership | | Billing Services |
|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | |
| DR | | SR | Residential | | Residential | | Residential |
| DR-LI | | SR | Residential | | Residential | | Residential |
| DR-TOU | | TOU/IDR | Residential | | Residential | | Residential |
| DR-TOU-2 | | TOU/IDR | Residential | | Residential | | Residential |
| DM | | SR | Residential | | Residential | | Residential |
| DS | | SR | Residential | | Residential | | Residential |
| DT | | SR | Residential | | Residential | | Residential |
| DT-RV | | SR | Residential | | Residential | | Residential |
| D-SMF | | SR | Residential | | Residential | | Residential |
| EV-TOU | | TOU/IDR | Residential | | Residential | | Residential |
| EV-TOU-2 | | TOU/IDR | Residential | | Residential | | Residential |
| EV-TOU-3 | | TOU/IDR | Residential | | Residential | | Residential |
| **Commercial/Industrial** | | | | | | | |
| A | | SR | SmComm | | SmComm - 0ph, SR | SmComm - 3ph, SR | Commercial |
| A-TC | | SR | SmComm | | SmComm - 0ph, SR | | Commercial |
| A-TOU | | TOU/IDR | SmComm | | SmComm - TOU | | Commercial |
| AD | | TOU/IDR | SmComm | | SmComm - TOU | | Commercial |
| AY-TOU | | TOU/IDR | SmComm | | SmComm - TOU | | Commercial |
| AL-TOU | >20, <500 | TOU/IDR | SmComm | | SmComm - TOU | | Commercial |
| AL-TOU | >500 | TOU/IDR | | LargeComm & Ind | | LargeComm & Ind | Commercial |
| AO-TOU | >20, <500 | TOU/IDR | SmComm | | SmComm - TOU | | Commercial |
| AO-TOU | >500 | TOU/IDR | | LargeComm & Ind | | LargeComm & Ind | Commercial |
| NJ | | TOU/IDR | SmComm | | SmComm - TOU | | Commercial |
| I-3 | | TOU/IDR | | LargeComm & Ind | | LargeComm & Ind | Commercial |
| A6-TOU | | TOU/IDR | | LargeComm & Ind | | LargeComm & Ind | Commercial |
| A-V1 | | TOU/IDR | | LargeComm & Ind | | LargeComm & Ind | Commercial |
| A-V2 | | TOU/IDR | | LargeComm & Ind | | LargeComm & Ind | Commercial |
| RTP-2 | | TOU/IDR | | LargeComm & Ind | | LargeComm & Ind | Commercial |

Note: Rate Schedule A-V3, RTP-1, AL-TOU-C and A-V6-C have no customers currently taking services. These rate schedule are not part of the mapping.

# Mapping of Customer Segments to Rate Schedules for SDG&E

| Rate Schedule | Kw | Meter Reading | Meter Services | Meter Ownership | Billing Services |
|---|---|---|---|---|---|
| **Agricultural** | | | | | |
| PA | | SR | SmComm | SmComm - 3ph, SR | Commercial |
| PA-TOU | | TOU/IDR | SmComm | SmComm - TOU | Commercial |
| PA-T-1 | | TOU/IDR | SmComm | SmComm - TOU | Commercial |
| **Outdoor Lighting** | | | | | |
| OL-1R | | N/A | Residential | Residential | Residential |
| OL-1C | | N/A | SmComm | SmComm - TOU | Commercial |
| DWL | | N/A | Residential | Residential | Residential |
| LS-1 | | N/A | SmComm | SmComm - TOU | Commercial |
| LS-2 | | N/A | SmComm | SmComm - TOU | Commercial |
| LS-3 | | SR | SmComm | SmComm - TOU | Commercial |

Note: Rate Schedule A-V3, RTP-1, AL-TOU-C and A-V6-C have no customers currently taking services. These rate schedule are not part of the mapping.

APPENDIX B

SCE mapping of

Rate Schedules for Customer Groups-
Meter Ownership, Meter Services, and Meter Reading Credits

| <20 kW (non-TOU) | 20-500 kW (non-TOU) | >500 kW (non-TOU) & TOU-8 | TOUs |
|---|---|---|---|
| D | AD*GS-2 | AD*I-6-F-P | TOU-GS2A-P |
| D-APS | AD*TU-GS2B-P | AD*I-6-F-S | TOU-GS2A-S |
| D-CARE (D-LI) | AD*TU-GS2B-S | AD*I-6-F-T | TOU-GS2B-P (TOU-GS-P) |
| D-CARE-APS (D-LI-APS) | EDEFB*GS-2 | AD*I-6-I-P | TOU-GS2B-S (TOU-GS-S) |
| D-CARE-E (D-LI-E) | EDRF*GS-2 | AD*I-6-I-S | TOU-GS2B-S-S (TOU-GS-S-S) |
| D-CARE-E-APS (D-LI-E-APS) | EDRF*GS-2 | AD*I-6-I-T | TOU-GS2SCP-P (TOU-GS-SCP-P) |
| D-PG-S | EPC*GS-2 | AD*TOU-8-P | TOU-GS2SCP-S (TOU-GS-SCP-S) |
| D-S | EPC*TGS2SO-S | AD*TOU-8-S | TOUG2A-APS-S |
| DE | GS-2 | AD*TOU-8-S-P | TOUG2B-APS-P (TOU-GS-APS-P) |
| DE-APS | GS-2-APS | AD*TU8-SOP-P | TOUG2B-APS-S (TOU-GS-APS-S) |
| DE-S | GS-2-S | CRS-16B-F-P | TOU-GS2B-S-T (TOU-GS-S-T) |
| DM | SEQUOIA | CRS-16B-I-P | TOU-GS-P |
| DMS-1 | | CRS-16I-I-P | TOU-GS-S |
| DMS-2 | | CRS-TU8-B-T | TOU-GS-S-S |
| DMS-3 | | CRS-TU8-I-T | TOU-GS-SCP-P |
| GS-SP | | CR1-16B-F-P | TOU-GS-SCP-S |
| GS-TP | | CR1-16B-F-S | D-TOU-EV-1 |
| GS-1 | | CR1-16B-F-T | D-TOU-1 |
| GS-1-APS | | CR1-16B-I-P | D-TOU-2 |
| GS-1-G-S | | CR1-16B-I-S | TOU-GS-1 |
| GS-1-S | | CR1-16B-I-T | TOU-GS-1-APS |
| TC-1 | | CR1-16I-F-P | TOU-ALMP-2 |
| AD*TU-PA-B | | CR1-16I-F-S | TOU-PA-A |
| AD*TU-PA-BI | | CR1-16I-I-P | TOU-PA-A-I |
| AD*T7A2*TUPB | | CR1-16I-I-S | TOU-PA-B |
| AD*T7A2*TU6B | | CR1-16I-I-T | TOU-PA-B-I |
| AD*T7B2*PA1 | | CR1-TU8-B-P | TOU-PA-SCP |
| AD*T7B2*TUPB | | CR1-TU8-B-S | TOU-PA-SCP-1 |
| AD*T7B2*TU6A | | CR1-TU8-I-P | TOU-PA-SCP-2 |
| AD*T7B2*TU6B | | CR1-TU8-I-S | TOU-PA-1 |
| PA-1 | | CR116BF-P*16 | TOU-PA-1-I |
| PA-1-G-S | | CR116BF-S*16 | TOU-PA-3-1 |
| PA-1-I | | CR116BI-P*16 | TOU-PA-3-2 |
| PA-1-SPEC-S | | CR116BI-S*16 | TOU-PA-3A-1 |
| PA-2 | | CR116I-P*16 | TOU-PA-3A-2 |
| PA-2-I | | CR116I-S*16 | TOU-PA-4A-1 |
| PA-2-S | | CR1TU8B-P*T8 | TOU-PA-4A-2 |
| TP7A11*TPS11 | | CR1TU8B-S*T8 | TOU-PA-4A-3 |
| TUPA7A-1*PA1 | | CR1TU8I-P*T8 | TOU-PA-4AI-1 |
| TUPA7A-2*PA1 | | CR1TU8I-S*T8 | TOU-PA-4B-1 |
| TUPA7A-2*PA2 | | EDRF*TOU-8-S | TOU-PA-4B-2 |
| TUPA7A1*TPS1 | | EDWARDS-AFB | TOU-PA-4B-3 |
| TUPA7A1*TPS2 | | EPC*I-6-F-T | TOU-PA-4BI-1 |
| TUPA7A1*TUPB | | EPC*I-6-I-T | TOU-PA-5 |
| TUPA7A2*TPS1 | | I-6-E-SPA-P | TOU-PA-5-1 |
| TUPA7A2*TPS2 | | I-6-E-SPA-S | TOU-PA-6 |
| TUPA7A2*TUPB | | I-6-E-SPA-T | TOU-PA-6A |
| TUPA7A2*TU6A | | I-6-F-P | TOU-PA-6B |
| TUPA7A2I*TPS | | I-6-F-S | TOU-PAS-IN |
| TUPA7B-2*PA1 | | I-6-F-S-P | TOU-PAS2-IN |
| TUPA7B-2*PA2 | | I-6-F-S-S | DE-TOU-1 |
| TUPA7B2*TPS1 | | I-6-F-S-T | DE-TOU-2 |
| TUPA7B2*TUPB | | I-6-F-T | GS-TOU-EV-3 |
| TUPA7B2*TU6B | | I-6-I-P | |
| | | I-6-I-S | |
| | | I-6-I-S-P | |
| | | I-6-I-S-S | |
| | | I-6-I-S-T | |
| | | I-6-I-T | |

APPENDIX B

SCE mapping of
Rate Schedules for Customer Groups-
Meter Ownership, Meter Services, and Meter Reading Credits

| <20 kW (non-TOU) | 20-500 kW (non-TOU) | >500 kW (non-TOU) & TOU-8 | TOU's |
|---|---|---|---|
| | | I-6-SPA-P | |
| | | I-6-SPA-S | |
| | | I-6-SPA-T | |
| | | I-6SPA-P*I6P | |
| | | I-6SPA-S*I6S | |
| | | I-6SPA-T*I6T | |
| | | I6ESPA-P*I6P | |
| | | I6ESPA-S*I6S | |
| | | I6ESPA-T*I6T | |
| | | ILAQ-I-6-F-P | |
| | | MARCH-AFB | |
| | | RTP-2-I-1-P | |
| | | RTP-2-I-1-S | |
| | | RTP-2-I-1-T | |
| | | RTP-2-I-P | |
| | | RTP-2-I-S | |
| | | RTP-2-I-T | |
| | | RTP-2-P | |
| | | RTP-2-S | |
| | | RTP-2-S-S | |
| | | RTP-2-T | |
| | | RTP-3-P | |
| | | RTP-3-S | |
| | | RTPT-I-6-F-P | |
| | | RTPT-I-6-I-P | |
| | | RTPPT-I-6-P | |
| | | TOU-8-APS | |
| | | TOU-8-APS-P | |
| | | TOU-8-APS-S | |
| | | TOU-8-CR-2 | |
| | | TOU-8-P | |
| | | TOU-8-S | |
| | | TOU-8-S-P | |
| | | TOU-8-S-S | |
| | | TOU-8-S-T | |
| | | TOU-8-SF-P | |
| | | TOU-8-SF-S | |
| | | TOU-8-SI-P | |
| | | TOU-8-SI-S | |
| | | TOU-8-SCP-P | |
| | | TOU-8-SCP-S | |
| | | TOU-8-T | |

SCE mapping of

Rate Schedules for Customer Groups-
Partial ESP Consolidated Billing Credits

| < 20 kW | 20-500 kW | > 500 kW |
|---|---|---|
| D | AD*GS-2 | AD*I-6-F-P |
| D-APS | AD*TU-GS2B-P | AD*I-6-F-S |
| D-CARE (D-LI) | AD*TU-GS2B-S | AD*I-6-F-T |
| D-CARE-APS (D-LI-APS) | EDEFB*GS-2 | AD*I-6-I-P |
| D- CARE-E (D-LI-E) | EDRF*GS-2 | AD*I-6-I-S |
| D-CARE-E-APS (D-LI-E-APS) | EDRP*GS-2 | AD*I-6-I-T |
| D-PG-S | EPC*GS-2 | AD*TOU-8-P |
| D-S | EPC*TGS2SO-S | AD*TOU-8-S |
| D-TOU-EV-1 | GS-2 | AD*TOU-8-S-P |
| D-TOU-1 | GS-2-APS | AD*TU8-SOP-P |
| D-TOU-2 | GS-2-S | CRS-16B-F-P |
| DE | SEQUOIA | CRS-16B-I-P |
| DE-APS | TOU-GS2A-P | CRS-16I-I-P |
| DE-S | TOU-GS2A-S | CRS-TU8-B-T |
| DE-TOU-1 | TOU-GS2B-P (TOU-GS-P) | CRS-TU8-I-T |
| DE-TOU-2 | TOU-GS2B-S (TOU-GS-S) | CR1-16B-F-P |
| DM | TOU-GS2B-S-S (TOU-GS-S-S) | CR1-16B-F-S |
| DMS-1 | TOU-GS2SCP-P (TOU-GS-SOP-P) | CR1-16B-F-T |
| DMS-2 | TOU-GS2SCP-S (TOU-GS-SOP-S) | CR1-16B-I-P |
| DMS-3 | TOUG2A-APS-S | CR1-16B-I-S |
| GS-SP | TOUG2B-APS-P(TOU-GS-APS-P) | CR1-16B-I-T |
| GS-TOU-EV-3 | TOUG2B-APS-S (TOU-GS-APS-S) | CR1-16I-F-P |
| GS-TP | TOU-GS2B-S-T (TOU-GS-S-T) | CR1-16I-F-S |
| GS-1 | TOU-GS-P | CR1-16I-I-P |
| GS-1-APS | TOU-GS-S | CR1-16I-I-S |
| GS-1-G-S | TOU-GS-S-S | CR1-16I-I-T |
| GS-1-S | TOU-GS-SCP-P | CR1-TU8-B-P |
| TC-1 | TOU-GS-SCP-S | CR1-TU8-B-S |
| TOU-GS-1 | | CR1-TU8-I-P |
| TOU-GS-1-APS | | CR1-TU8-I-S |
| AL-1 | | CR116BF-P*16 |
| DWL-A | | CR116BF-S*16 |
| DWL-B | | CR116BI-P*16 |
| DWL-C | | CR116BI-S*16 |
| LS-1-ALLNITE | | CR116I-P*16 |
| LS-1-MIDNITE | | CR116I-S*16 |
| LS-2 | | CR1TU8B-P*T8 |
| LS-3 | | CR1TU8B-S*T8 |
| LS1-TAP | | CR1TU8I-P*T8 |
| OL-1-ALLNITE | | CR1TU8I-S*T8 |
| OL-1-MIDNITE | | EDRF*TOU-8-S |
| AD*TU-PA-B | | EDWARDS-AFB |
| AD*TU-PA-BI | | EPC*I-6-F-T |
| AD*T7A2*TUPB | | EPC*I-6-I-T |
| AD*T7A2*TU6B | | I-6-E-SPA-P |
| AD*T7B2*PA1 | | I-6-E-SPA-S |
| AD*T7B2*TUPB | | I-6-E-SPA-T |
| AD*T7B2*TU6A | | I-6-F-P |
| AD*T7B2*TU6B | | I-6-F-S |
| PA-1 | | I-6-F-S-P |
| PA-1-G-S | | I-6-F-S-S |
| PA-1-I | | I-6-F-S-T |
| PA-1-SPEC-S | | I-6-F-T |
| PA-2 | | I-6-I-P |
| PA-2-I | | I-6-I-S |
| PA-2-S | | I-6-I-S-P |
| TOU-ALMP-2 | | I-6-I-S-S |
| TOU-PA-A | | I-6-I-S-T |
| TOU-PA-A-I | | I-6-I-T |

SCE mapping of

**Rate Schedules for Customer Groups-**
**Partial ESP Consolidated Billing Credits**

| < 20 kW | 20-500 kW | > 500 kW |
|---|---|---|
| TOU-PA-B | | I-6-SPA-P |
| TOU-PA-B-I | | I-6-SPA-S |
| TOU-PA-SOP | | I-6-SPA-T |
| TOU-PA-SOP-1 | | I-6SPA-P*I6P |
| TOU-PA-SOP-2 | | I-6SPA-S*I6S |
| TOU-PA-I | | I-6SPA-T*I6T |
| TOU-PA-I-I | | I6ESPA-P*I6P |
| TOU-PA-3-1 | | I6ESPA-S*I6S |
| TOU-PA-3-2 | | I6ESPA-T*I6T |
| TOU-PA-3A-1 | | BLAQ-I-6-F-P |
| TOU-PA-3A-2 | | MARCH-AFB |
| TOU-PA-4A-1 | | RTP-2-I-I-P |
| TOU-PA-4A-2 | | RTP-2-I-I-S |
| TOU-PA-4A-3 | | RTP-2-I-I-T |
| TOU-PA-4AI-1 | | RTP-2-I-P |
| TOU-PA-4B-1 | | RTP-2-I-S |
| TOU-PA-4B-2 | | RTP-2-I-T |
| TOU-PA-4B-3 | | RTP-2-P |
| TOU-PA-4BI-1 | | RTP-2-S |
| TOU-PA-5 | | RTP-2-S-S |
| TOU-PA-5-I | | RTP-2-T |
| TOU-PA-6 | | RTP-3-P |
| TOU-PA-6A | | RTP-3-S |
| TOU-PA-6B | | RTPT-I-6-F-P |
| TOU-PA5-IN | | RTPT-I-6-I-P |
| TOU-PA52-IN | | RTPPT-I-6-P |
| TP7A1I*TP5II | | TOU-8-APS |
| TU7A/A-1*PA1 | | TOU-8-APS-P |
| TU7A/A-2*PA1 | | TOU-8-APS-S |
| TU7A/A-2*PA2 | | TOU-8-CR-2 |
| TU7A/A1*TP51 | | TOU-8-P |
| TU7A/A1*TP52 | | TOU-8-S |
| TU7A/A1*TU7B | | TOU-8-S-P |
| TU7A/A2*TP51 | | TOU-8-S-S |
| TU7A/A2*TP52 | | TOU-8-S-T |
| TU7A/A2*TU75 | | TOU-8-SF-P |
| TU7A/A2*TU6A | | TOU-8-SF-S |
| TU7A/A2I*TP5 | | TOU-8-SI-P |
| TU7A/B-2*PA1 | | TOU-8-SI-S |
| TU7A/B-2*PA2 | | TOU-8-SOP-P |
| TU7A/B2*TP51 | | TOU-8-SOP-S |
| TU7A/B2*TU7B | | TOU-8-T |
| TU7A/B2*TU6B | | |

(End of Appendix B)