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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Portions of AB 117 Concerning Community Choice Aggregation.	FILED PUBLIC UTILITIES COMMISSION OCTOBER 2, 2003 RULEMAKING 03-10-003

ORDER INSTITUTING RULEMAKING TO IMPLEMENT PORTIONS OF AB 117 CONCERNING COMMUNITY CHOICE AGGREGATION

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I. Summary

This order institutes a rulemaking to implement Assembly Bill (AB) 117 (Chapter 838, September 24, 2002). AB 117 added Public Utilities Code Sections 218.3, 331.1, 366.2, 381.1, and 394.25, permitting cities and counties to purchase and sell electricity on behalf of utility customers in their jurisdictions after they have registered with the Commission as "Community Choice Aggregators." This rulemaking order proposes ways to implement relevant portions of Assembly Bill (AB) 117 and solicits comments from jurisdictional utilities and other parties on those proposals.

II. Background on AB 117

California's energy crisis motivated some local governments and communities to take a more active role in energy policy and planning on behalf of local residents and businesses. In some cases, local governments may be in a position to implement energy programs. Responding to the interest of local governments in energy policy and programs, AB 117 allows local governments "…to elect to combine the loads of its residents, businesses, and municipal facilities, in a community-wide electricity buyers' program." (Pub. Util. Code § 331.1(a).) The statute permits a local government board, or combination of governments to create an entity called a "Community Choice Aggregator" (CCA), which may procure electricity on behalf of local citizens, businesses, and itself.[1] AB 117[2] provides local governments greater discretion over the type and source of electric generation their communities use.

AB 117 involves Commission-jurisdictional utilities by requiring them to continue to provide distribution, metering and billing services to the CCA's energy customers. It requires those utilities to provide certain types of notice to CCA customers and to act as providers of last resort. AB 117 also directs the Commission to assure the utilities recover certain costs, including those associated with energy contracts signed by the state's Department of Water Resources (DWR) and the costs of providing ongoing services to CCAs and their customers.

AB 117 directs the CCA to provide the Commission with an "implementation plan" (Pub. Util. Code § 366.2(c)(5)) and a "statement of intent" as part of a registration procedure. (Pub. Util. Code § 366.2(c)(4).) AB 117 appears to make the CCA responsible for ratemaking, customer rights and obligations, customer protection, universal access, reliability, and equitable treatment of all customer classes.

This order proposes rules addressing the responsibilities of the electric utilities, the cost recovery mechanism and re-entry fees, notification

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1 AB 117 allows local governments to procure and provide electricity to retail customers. It does not allow local governments to provide natural gas to customers.

2 AB 117 also enables local government to pursue demand side management programs to reduce their community's energy usage, including increased coordination with Public Goods Charge (PGC) energy efficiency and conservation program administrators and the ability to apply for PGC administration and funding for energy efficiency and conservation programs on behalf of their customers. We address this issue in Rulemaking (R.) 01-002-028.

requirements, transaction costs, and the process CCAs would use to register with the Commission. In general, we propose to adapt many existing procedures and rules to CCAs wherever possible in order to facilitate the initiation of the program and implement the statute. The rules and charges we have developed for "electric service providers" and "direct access" customers may be applicable in many cases, as we describe in subsequent sections. A copy of AB 117 is attached as Attachment B.

III. Scope of Proceeding

This proceeding proposes ways to resolve several broad issues and presents corresponding proposed rules. (See Attachment A.)

A. Definition of Community Choice Aggregator

AB 117 defines CCAs as entities formed by a city, county or group of cities and counties, or a joint power authority:

> Section 331.1. For purposes of this chapter, "community choice aggregator" means any of the following entities,
>
> 1. Any city, county, or city and county whose governing board elects to combine the loads of its residents, businesses, and municipal facilities in a community wide electricity buyers' program.
>
> 2. Any group of cities, counties, or cities and counties whose governing boards have elected to combine the loads of their programs, through the formation of a joint powers agency established under Chapter 5 (commencing with Section 6500) of Division 7 of Title 1 of the Government Code.

AB 117 does not define any role for the Commission in creating a CCA or authorizing its activities. However, AB 117 establishes three preconditions to the initiation of community choice aggregation programs:

a. The Commission must adopt a "cost-recovery mechanism" so that the investor owned utility is able to recoup certain costs associated with state power purchase contracts (Section 366.2(h) and (i)(1));

b. The Commission must submit a report to the State Legislature "certifying compliance" with provisions relating to the cost-recovery mechanism (Section 366.2(i)(2)); and

c. The Commission must adopt "rules for implementing community choice aggregation." (Section 366.2 (i)(3).)

This rulemaking is initiated for the purpose of developing the rules required as a precondition to authorizing community choice aggregation, consistent with Section 366.2(i)(3). Among the topics we address below are the cost recovery mechanism and the Commission's report to the legislature.

B. Utility Obligations

Several sections of AB 117 require the local investor-owned utility to provide certain services. Section 366.2(c)(9) specifically provides that "(t)he commission shall determine the terms and conditions under which the electrical corporation provides services to community choice aggregators and retail customers." We address related issues below.

1. Utility Delivery Services

Section 366.2 (c)(11) requires that the serving utility provide delivery services at the same rates, terms, and conditions as for direct access customers that have been approved by the Commission:

> Delivery services shall be provided at the same rates, terms, and conditions, as approved by the commission, for community choice aggregation customers and customers that have entered into a direct transaction where applicable, as determined by the commission.

For these purposes, a CCA's relationship with the local distribution utility appears comparable to that relationship between the utility and an "electric service provider"(ESP) in that the utility is providing an identical service to entities that are offering retail energy services to local customers. Therefore, we propose to apply the direct access service rules and service agreements to CCAs. Those rules require, among other things, the execution of a service agreement that describes the responsibilities of each party, and utility charges for delivery services.

PG&E's Rule 22, SCE's Rule 22 and SDG&E's Rule 25 describe delivery services to ESPs and we propose that these tariffs be modified to incorporate AB 117 requirements for CCAs. As modified, the tariffs would describe the respective responsibilities of customers, CCAs and utilities in cases where a utility customer in a CCA's territory decides to remain with the utility.

2. Utility Metering, Customer Service and Billing Services

AB 117 requires the utilities to continue to provide " all metering, billing, collection, and customer service to retail customers that participate in community choice aggregation programs." We propose to apply related existing ESP requirements to CCAs. (Section 366.2(c)(9). The same section also provides that:

> "(b)ills sent by the electrical corporation to retail customers shall identify the community choice aggregator as providing the electrical energy component of the bill. The commission shall determine the terms and conditions under which the electrical corporation provides services to community choice aggregators and retail customers."

Existing utility tariffs provide consolidated billing to ESP customers, metering, customer service and collections, and we propose that these tariffs be modified to incorporate services to CCAs and their customers.

3. Provider of Last Resort to CCA Customers

Section 366.2(a)(3) provides that if a customer decides not to take electrical service from a CCA, or has no CCA program available, the local investor-owned utility must provide service to that customer.

Each utility should propose tariff changes that reflect this obligation and provide for notification of the utility's distribution customers.

4. Metering Services

Section 366.2(c)(18) requires the serving utility to "install, maintain and calibrate metering devices at mutually agreeable locations within or adjacent to the community aggregator's political boundaries" at the request and at the expense of a CCA, and in ways that do not "compromise the safety, reliability or operational flexibility" of the utility's facilities. It requires the utility to "read the metering devices and provide the data collected to the community aggregator at the aggregator's expense."

Utilities should propose specific tariff language to meet this requirement.

5. Customer Notification

Section 366.2(c) 13 provides that "the community choice aggregator may request the commission to approve and order the electrical corporation to provide the notification" required of CCAs by AB 117.

Each utility should propose tariff language that offers this notification service. We address how the utilities may recover associated costs in a subsequent section.

6. Transferring Service

Section 366.2(c)(16) provides that "(o)nce notified of a community choice aggregator program, the electrical corporation shall transfer all applicable accounts to the new supplier within a 30-day period from the date of the close of their normally scheduled monthly metering and billing process. We propose that this transfer occur no sooner than 30 days following the Commission's notice to the CCA of its approval of the CCA's registration packet, service agreement and CRS. We discuss this notice procedure in Section III.F of this order.

7. Information to CCAs and Entities Considering Community Choice Aggregation Programs

Section 366.2(c)(9) requires that utilities:

> "cooperate fully with any community choice aggregators that investigate, pursue, or implement community choice aggregation programs. Cooperation shall include providing the entities with appropriate billing and electrical load data, including, but not limited to, data detailing electricity needs and patterns of usage, as determined by the commission, and in accordance with procedures established by the commission."

We here state our intention to promote the provision of useful and timely information to entities designated as CCAs or contemplating the creation of a CCA. We understand that the prospects for worthwhile CCA programs may depend on the availability of good information.

The Commission recently ordered Pacific Gas and Electric Company (PG&E), San Diego Gas & Electricity (SDG&E), and Southern California Edison (SCE) to provide certain types of existing information to CCAs to facilitate the development of their energy efficiency program proposals (See D.03-07-034.) We also directed the utilities to submit tariffs that would provide other types of information to CCAs at cost. The information and analysis the utilities will provide at no cost may be useful to CCAs in developing procurement strategies as well. However, they may require additional information.

The utilities and other parties may comment on whether the information requirements adopted in energy efficiency proceeding (R.01-08-028) are adequate for purposes of Section 366.2 (c)(9) and whether and how these requirements should be augmented or changed for purposes of implementing Section 366.2(c)(9). We intend to address this issue in a workshop in the near future.

8. Applicability to Small Electrical Corporations

AB 117 applies equally to all jurisdictional electric utilities. However, the task of developing tariffs is an elaborate one for a small utility that may not ultimately serve CCAs. For that reason, this order requires only PG&E, SCE and SDG&E to submit specific language and proposals at this time. We ask that the parties propose circumstances under which other jurisdictional utilities should develop tariffs.

Similarly, we seek the parties' proposals on whether and how the Commission should adopt cost recovery surcharges for the jurisdictional electric utilities that do not already have them. We are particularly interested in the assessments of those smaller utilities with regard to potential liabilities they may have that would qualify for treatment in a CRS.

C. Recovery of Utility Costs

1. Cost Recovery for Transaction Services Provided to CCAs

Section 366.2(c)(17) provides that a utility "shall recover from the community choice aggregator any costs reasonably attributable to the community choice aggregator, as determined by the commission…including, but not limited to, all business and information system changes…notices, billing, metering, collections, and customer communications or other services provided to an aggregator or its customers." That section provides that the CCA will assume the costs of those utility services but also provides that those costs "not reasonably attributable to a community choice aggregator shall be recovered from ratepayers."

We interpret this section to mean that any cost associated with a specific CCA shall be recovered from the CCA. Any costs of program administration generally would be included in utility rates. Direct Access Service tariffs establish charges allowing the utilities to recover incremental costs associated with services provided to ESPs, such as customer notifications, metering and billing. We propose that these tariff rules apply to CCAs. We suggest that parties refer to PG&E's Schedules (E-ESP, E-EUS and E-DASR) for examples of tariffs for fees for transactional based services established for billing related services. (www.pge.com/customer_services/business/tariffs.)

The utilities should propose ways to reflect costs associated with specific CCAs in tariffs for each type of relevant service. They should also propose ways to recover program costs not associated with a specific CCA, including how those costs should be allocated to "ratepayers," consistent with the statute.

2. Cost Responsibility Surcharges (CRS)

AB 117 provides that before a CCA may begin aggregating load, the Commission must establish cost responsibility surcharges (CRS) for which the CCA and its customers would assume responsibility. These surcharges allow the utility to recover certain energy purchase costs the utility would continue to incur after losing customers to the CCA. Imposing those costs on CCA customers will also ensure that remaining utility customers will not assume liability for costs originally incurred on behalf of a larger customer base. Such costs include those associated with energy contracts signed by and bonds issued by the DWR during the energy crisis, and certain utility costs for previous electricity purchases (Section 366.2(d)(e)(f)).

Section 366.2(c)(5) anticipates the Commission will review the CCA's Implementation Plan to determine the applicable CRS. Section 366.2(c)(8) requires the Commission to determine the applicable CRS for CCAs taking into consideration the utilities' approved procurement plans.

Section 366(2)(d), (e), (f) and (g), as enacted by AB 117, requires that the CRS applied to CCAs include the same components as those that comprise the CRS for direct access customers, including DWR electricity purchase costs, bond related and administrative costs for the DWR purchases and other unrecovered energy contract costs. Whether the level of the CRS for CCA customers would be the same as we apply to DA customers is unclear because DA customers assume certain undercollections that may not logically apply to CCA customers and may not be liable for certain future costs. D.02-11-022 and D.02-12-045 describe how we set the CRS for direct access customers.

We seek the parties' comments on how we should set the CRS for CCA customers. In addition, we will consider parties' proposals to reduce the CRS, for example, where a CCA assumes liability for a utility's DWR energy contract commitments.

3. Re-entry Fees

Section 366.2(c)(11) provides that CCA customers who voluntarily return to their local utility will be subject to the same terms and conditions as are applicable to other returning direct access customers. Utility re-entry fees must be based on the utility's cost of reestablishing service and approved by the Commission.

Section 394.25(e) provides that the same fee is to be paid by the CCA when a CCA customer is returned to utility service on an involuntary basis, except if "a customer [is] returned due to default in payment or other contractual obligations or because the customer's contract has expired."

This section applies equally to ESPs and their customers.[3] We therefore propose to apply to CCA customers the re-entry fees assumed by direct access customers returning to utility service. The utilities currently do not impose re-entry fees. Direct access customers that elect to return to utility bundled service must provide the utility six months' notice and make a three year minimum commitment to receive the bundled portfolio rate. During the six-month period, the customer's rate reflects the spot price of power and includes CRS undercollections incurred in prior periods. We direct the utilities to propose associated accounting mechanisms and tariff language consistent with our proposal.

D. Obligations of CCAs

1. CCA Implementation Plans and Statements of Intent

AB 117 requires a CCA to submit to the Commission an Implementation Plan and Statement of Intent, which describe specified elements of the CCA program.

a. An organizational structure of the program, its operations, and its funding.

b. Ratesetting and other costs to participants.

c. Provisions for disclosure and due process in setting rates and allocating costs among participants.

d. The methods for entering and terminating agreements with other entities.

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[3] The exception is in the event of insolvency, in which case the statute requires that the customers of an ESP, but not a CCA, will assume the re-entry fees.

e. The rights and responsibilities of program participants, including, but not limited to, consumer protection procedures, credit issues, and shutoff procedures.

f. Termination of the program.

g. description of the third parties that will be supplying electricity under the program, including, but not limited to, information about financial, technical, and operational capabilities. (Section 366.2 (c)(3).)

The Implementation Plan and Statement of Intent should also include the following information about programs the statute requires CCAs to "provide for:"

a. Universal access.

b. Reliability.

c. Equitable treatment of all classes of customers, and

d. Any requirements established by state law or by the Commission concerning aggregated service. (Section 366.2(c)(4).)

Section 366.2(c)(5) anticipates the implementation plan will guide the Commission's application of the CRS to CCA customers. It also requires CCAs to provide "any other information requested by the Commission that the Commission determines is necessary to develop the cost-recovery mechanism."

2. The Renewable Portfolio Standard

Pub. Util. Code § 399.12(b)(2) requires the Commission to institute a rulemaking "to determine the manner in which a CCA will participate in the RPS subject to the same terms and conditions applicable to an electrical corporation."[4]

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[4] Section 399.12(b)(2) was added to the Pub. Util. Code by Senate Bill 1078 (Stats. 2002, Ch. 516).

Existing Commission policy requires each jurisdictional utility to increase electricity generated by renewable resources by at least 1% a year, until 20% of its sales portfolio is comprised of renewable energy resources. We intend to address the application of these requirements to CCAs in the rulemaking where we are considering procurement issues (R.01-10-024).

3. Insurance and Bonds

Section 394.25(e) requires CCAs to post a bond or purchase insurance adequate to cover the costs of re-entry if their customers are involuntarily returned to utility electric procurement services. We have proposed in Section III.C.3 that the re-entry fees applicable to ESPs also apply to CCAs. We propose that the insurance or bond coverage equal the adopted re-entry fee, if any, times the number of customers served by the CCA.

4. Customer Protections

AB 117, specifically the implementation plan and statement of intent portions of the law, largely makes the CCA the government entity responsible for ratemaking, customer rights and obligations, customer protection, universal access, reliability, and equitable treatment of all customer classes. The CCA assumes and describes these roles in the implementation plan it submits to this Commission. But AB 117 stops short of transferring the Commission's consumer protection responsibilities to the CCA, explicitly stating that the Commission ". . . may require additional information [from the CCA] to ensure compliance with basic consumer protection rules." (Pub. Util. Code § 366.2(c)(14).)

We expect that local government entities will be responsive to the varied needs of diverse customers in their jurisdictions – from low income and medically impaired customers to small and large businesses, for example. We also expect that, in fulfilling the responsibilities to be described in the implementation plan and statement of intent, the CCA will demonstrate its responsiveness to its customers' needs through the programs and consumer protections it will provide. The Commission proposes in this rulemaking to refrain from imposing specific consumer protection rules in adopting rules for community choice aggregation. (Pub. Util. Code § 366.2(1)(3).)

Instead, the rules we propose for adoption will address the responsibilities of the electric utilities, the establishment of a cost recovery mechanism, re-entry fees, notification of the utility in the event of termination of CCA service, transaction costs, and the process for Commission authorization.

Some of the proposals in this rulemaking address some type of consumer protection, for example, opt out provisions, protections against cost shifting and certain customer notice requirements. These issues, however, involve protections for customers of utilities the Commission regulates. As stated above, our initial analysis of AB 117 leads us to presume that the Legislature did not intend for this Commission to regulate local governments with regard to consumer protections that are not specified in the statute. However, we assume that local governments are providing such protections. We may be convinced otherwise and invite the parties to brief the requirements of Section 366.2(c)(14) in this regard. Accordingly, we do not propose here that CCAs conform their operations and policies to all of those we have required of jurisdictional utilities. Examples of such consumer protections are service requirements and more elaborate notice requirements. Nevertheless, the statute appears to anticipate that CCA customers would have reasonable protections, as well as adequate and reliable service notwithstanding the Commission's role.

Whether or not we ultimately adopt protections for CCA customers that go beyond those specified in AB 117, we believe CCAs would benefit from the experience of Commission staff, regulated utilities and the many parties to our proceedings who have worked to develop rates, standards and practices designed to promote the interests of consumers and the general public. CCAs should be encouraged to take advantage of their joint and individual efforts. For example, CCAs may wish to apply the standards developed for procurement portfolios, utility customer service and system reliability. Another critical element for CCAs to address is how to design special rates for customers with low incomes and medical conditions. In addition to addressing the Commission's role in promoting protection of CCA customers, we ask the parties to address how the Commission can assist CCAs in understanding these issues and facilitating consumer protections and quality service.

A related matter is how the CARE discount would apply to CCA customer's energy bills. We propose here that the utilities automatically apply the CARE discount to that portion of a CCA customer's bill that reflects CCA energy costs. Reimbursements for the discount would be billed to the CARE program so that CCAs would be financially indifferent. We invite the parties to comment on this option.

5. "Opt Out" Provision for Utility Customers

Section 366.2(c)(11) provides that a CCA must "allow any retail customer to opt out and to continue to be served as a bundled service customer" of the utility. Our rules should address the Commission's role in assuring utility customers are protected from being transferred to the CCA contrary to their wishes. We also seek proposals from the utilities that would assure customer requests to remain with the utility are honored and processed effectively.

Specifically, each utility should describe how it would process opt-out requests with timeliness and operations charts.

In addition, Section 366.2(c)(13)(C) clearly anticipates that the opt-out procedure will be simple for customers to understand and affect. We intend to adopt procedures with that in mind. Some options include self-addressed postcards and/or a check-off on the utility bill.

6. CCA Customer Notification Requirements

Section 366.2(c)(13) requires the CCA to notify utility customers in its area of the CCA's intent to provide service and the customers' option to opt out as follows:

> a. The community choice aggregator shall fully inform participating customers at least twice within two calendar months, or 60 days, in advance of the date of commencing automatic enrollment. Notifications may occur concurrently with billing cycles. Following enrollment, the aggregated entity shall fully inform participating customers for not less than two consecutive billing cycles. Notification may include, but is not limited to, direct mailings to customers, or inserts in water, sewer, or other utility bills. Any notification shall inform customers of both of the following:
>
> (1) That they are to be automatically enrolled and that the customer has the right to opt out of the community choice aggregator without penalty.
>
> (2) The terms and conditions of the services offered.
>
> (3) The community choice aggregator may request the commission to approve and order the electrical corporation to provide the notification required in subparagraph (A). If the commission orders the electrical corporation to send one or more of the notifications required pursuant to subparagraph (A) in the electrical corporation's normally scheduled monthly billing process, the electrical corporation shall be entitled to recover from the community choice aggregator all reasonable incremental costs it incurs

related to the notification or notifications. The electrical corporation shall fully cooperate with the community choice aggregator in determining the feasibility and costs associated with using the electrical corporation's normally scheduled monthly billing process to provide one or more of the notifications required pursuant to subparagraph a.

(4) Each notification shall also include a mechanism by which a ratepayer may opt out of community choice aggregated service. The opt out may take the form of a self-addressed return postcard indicating the customer's election to remain with, or return to, electrical energy service provided by the electrical corporation, or another straightforward means by which the customer may elect to derive electrical energy service through the electrical corporation providing service in the area.

We propose that the CCA describe in its registration packet its plan for notifying customers, as required by Section 366.2(c)(13) and that the utility service agreement and tariffs require evidence of this notification prior to the utility's transfer of service to the CCA. Parties may also propose to comment on other notice options, for example, utility notices in utility bills describing the CCA program prior to its initiation.

We also propose that utility tariffs specify the utility's obligation to provide information about "the feasibility and costs associated with using the electrical corporation's normally scheduled monthly billing process."

7. Notice of Utility of Customer Transfer

Section 366.2(c)(15) provides that "(o)nce the community choice aggregator's contract is signed, the community choice aggregator shall notify the applicable electrical corporation that community choice service will commence within 30 days."

We propose that the Service Agreement signed by the utility and the CCA meets the type of contract referred to in Section 366.2(c)(15). We also interpret this provision to mean that aggregation will not occur in less than 30 days after the contract is signed in order to provide time for the utility to make necessary system changes.

8. Termination of CCA Program

In the event that a CCA decides to discontinue its aggregation program, utility ratepayers must be protected from service problems and additional costs. We propose existing Commission rules required of Direct Access customers also be applied to CCAs. Specifically, CCAs would have to provide notice of program termination at least six months in advance. If during that six months, the CCA returns its customers to bundled service, it would pay electric rates that reflect the utility's prices on the spot market. We also propose that the CCA notify customers of program termination twice during the 60-day period before termination. If the CCA transfers the customers to the utility before the six-month notice period, the CCA's notices to customers would explain the customers' liability for utility spot market purchases.

Before a CCA may offer aggregated services to local customers, Section 366.2(c)(14) requires each CCA to "register with the commission." This section also gives the Commission authority to "require additional information to ensure compliance with basic consumer protection rules and other procedural matters."

We propose that this registration process be initiated with the filing of a CCA's Implementation Plan. Its registration packet should include the kind of documents and information required of ESPs:

a. **A Service Agreement with the utility** serving each service territory in which the CCA plans to offer service. We propose that this Service Agreement be a version of the existing ESP IOU Service Agreement modified for CCAs and consistent with the Direct Access Service Rules. This Service Agreement would fulfill the requirements of the CCA "contract" referred to in Section 366.2(c)(15).

b. **A signed agreement** with a scheduling coordinator authorized by the Independent System Operator. **This requirement would be waived For CCAs authorized as scheduling coordinators.**

c. **Evidence of a bond or insurance adequate to cover potential re-entry fees. (Section 394.25(e).)**

As we see it, the process of registration and Commission approval would be comparable to that applied to ESPs, plus the additional requirements imposed on the Commission:

(1) CCA files registration packet;

(2) Within 10 days of the CCA's filing, the Commission notifies the utility serving the customers proposed for aggregation of the CCA's. (Section 366.2(c)(6));

(3) Within 90 days after the community choice aggregator files its implementation plan, the Commission certifies to the CCA that it has received the implementation plan, including any additional information necessary to determine a cost-recovery mechanism. (Section 366.2(c)(7));

(4) Notice by the Commission of the amount of cost recovery that must be paid by future CCA customers. (Section 366.2(c)(7)); and

(5) Notice by the Commission of the earliest possible effective date for implementation of a CCA program, taking into consideration the impact on any annual

> procurement plan of the electrical corporation that has been approved by the Commission. Section 366.2(8).

Consistent with our procedures for registering ESPs, we propose that staff designated by the Commission's Executive Director conduct these procedures. We propose that the Executive Director or designee sign all notices, including those authorizing CCA activity. We also propose that, following receipt of the Commission letter, the CCA inform the Executive Director that (1) the utility and the CCA have signed the designated service agreement and (2) the CCA has requested the transfer of service.

We may also need information from CCAs about how their programs change. Some options we may consider are (1) periodic re-registration; (2) annual reports providing information about program changes; and/or (3) investigations if and when we receive information to suggest problems that affect CCA customers or utilities serving them. We invite the parties to comment on these and other options that would serve the public's interest in understanding CCA programs and getting good service.

E. Reports to Legislature

1. Report on the CCA Program

AB 117 requires the Commission to submit a report to the state Legislature by January 1, 2006 (Section 366.2(j)). The report must detail "the number of community choices aggregations, the number of customers served by community choice aggregations, third party suppliers to community choice aggregations, compliance with this section, and the overall effectiveness of community choice aggregation programs."

The Commission's report will require our collection of certain information from utilities and established CCAs. We propose that each CCA provide to the

Commission an annual report that states the number of customers it serves and the number, type and status of third party power suppliers used by the CCA.

Sometime during 2005, we intend to solicit comments and additional information from CCAs and other parties relating to the effectiveness of CCA programs and other matters relevant to the Commission's report to the Legislature.

2. Report Demonstrating Compliance with CRS Requirements

Section 366.2(i)(2) prohibits the Commission from authorizing community choice aggregation "until it submits a report certifying…(that it has adopted a cost recovery surcharge) to the Senate Energy, Utilities and Communications Committee, or its successor, and the Assembly Committee on Utilities and Commerce, or its successor." We intend to submit our final order in this rulemaking to the Legislative committees and supporting documents to certify compliance with Section 366.2(d)(e) and (f), which describe the cost recovery surcharge.

IV. Scoping Memo

A. Proceeding Category and Schedule

We initiate a rulemaking that will consider the topics identified above. We categorize this proceeding as "ratesetting" as the term is defined in Rule 5(d) in recognition that this will address the development of utility rates for CCA services in addition to resolving broad policies and rules.

The Assigned Commissioner and Administrative Law Judge (ALJ) should promptly convene a prehearing conference to determine how to manage this proceeding, for example, whether to address some issues in advance of others, whether hearings are required and other procedural matters. At this time, we order a round of comments on the proposals and topics presented in this order and any others the parties believe the Commission must consider to implement those portions of AB 117 addressing CCA procurement. The initial schedule in this proceeding is as follows:

Opening Comments	October 22
Prehearing Conference/Workshop	October 29

The Assigned Commissioner or ALJ may change the schedule for the sake of fair and efficient proceeding management, either by ruling or at a prehearing conference.

At this time we do not anticipate a need for hearings. However, we encourage the parties to address in their opening comments the need for hearings and identify topics that are appropriate subjects for hearing. Parties may also address the need for hearings in response to future pleadings, testimony, Commission decisions or rulings.

Any party filing opening comments may object to (1) the preliminary categorization of this consolidated proceeding as ratesetting (2) the determination that there is no need for hearings and (3) the scope and schedule for the proceeding. Any party who proposes a hearing should describe (1) material issues of disputed fact and (2) the evidence the party would introduce at a hearing.

B. Service List for Proceeding

Anyone wishing to be placed on the service list for this proceeding should inform the Commission Process Office by electronic mail at (ALJ_Process@cpuc.ca.gov) within 20 days of the mailing date of this order or in writing to the Process Office, 505 Van Ness Avenue, San Francisco, California 94102. Parties should refer to this proceeding number and include their name, the name of their representative (if any), address, and telephone numbers. Parties should also provide an e-mail address or indicate that no email address is available. The service list will be posted on the Commission's web site at www.cpuc.ca.gov.

Parties interested in participating in this rulemaking who are unfamiliar with the Commission's procedures should contact the Commission's Public Advisor's Office in San Francisco at (415) 703-2074, or in Los Angeles at (213) 649-4782.

C. Electronic Service Protocols

1. Party Status in Commission Proceedings

To reduce the burden of service in this proceeding, the Commission will use electronic service, to the extent possible. These electronic service protocols apply to those individuals and entities who are named as respondents and to those who become "appearances" in this proceeding. In accordance with Commission practice, by entering an appearance at a hearing or by other appropriate means, an interested party or protestant gains "party" status. A party to a Commission proceeding has certain rights that non-parties (those in "state service" and "information only" service categories) do not have. For example, a party has the right to participate in evidentiary hearings, file comments on a proposed decision, and appeal a final decision. A party also has the ability to consent to waive or reduce a comment period. Non-parties do not have these rights, even though they are included on the service list for the proceeding and receive copies of some or all documents. When individuals write to the Process Office to request to be on the service list, they should indicate if they wish to be an appearance, and if so, they should indicate how they intend to participate in the proceeding. Electronic service will allow those individuals on the state service and information only categories to easily monitor the proceeding, as we discuss below.

Parties are not required to provide hard copy service to the service list unless a person on the service list requests hard copies. Nevertheless, hard copies of formal pleadings and other documents must be filed with the Commission's Docket Office consistent with Rule 2.

2. Service of Documents by Electronic Mail

To the extent possible, we intend to use electronic service in this proceeding. All individuals should provide electronic mail addresses and should indicate whether they consent to electronic service. We intend that parties serve documents on appearances, state service, and information only individuals by electronic mail, and in turn, shall accept service by electronic mail. Electronic service allows for convenient, efficient service and can also allow those on the state service and information only portions of the service list to easily monitor the proceeding. In addition, paper copies shall be served on the assigned Commissioner and assigned ALJ.

3. Notice of Availability

If a document, including attachments, exceeds 75 pages, parties may serve a Notice of Availability in lieu of all or part of the document, in accordance with Rule 2.3(c) of the Commission's Rules of Practice and Procedure.

4. Filing of Documents

These electronic service protocols govern service of documents only, and do not change the rules regarding the tendering of documents for filing. Documents for filing must be tendered in paper form, as described in Rule 2, et seq., of the Commission's Rules of Practice and Procedure.

5. Electronic Service Standards

As an aid to review of documents served electronically, appearances should follow these procedures:

- Merge into a single electronic file the entire document to be served (e.g., title page, table of contents, text, attachments, service list).
- Attach the document file to an electronic note.
- In the subject line of the note, identify the proceeding number; the party sending the document; and the abbreviated title of the document.
- Within the body of the note, identify the word processing program used to create the document if anything other than Microsoft Word. (Commission experience is that most recipients can readily open documents sent in Microsoft Word 6.0/95.)

If the electronic mail is returned to the sender, or the recipient informs the sender of an inability to open the document, the sender shall immediately arrange for alternative service (regular U.S. mail shall be the default, unless another means—such as overnight delivery—is mutually agreed upon).

Parties should exercise good judgment regarding electronic mail service, and moderate the burden of paper management for recipients. For example, if a particularly complex matrix or cost-effectiveness study with complex tables is an attachment within a document mailed electronically, and it can be reasonably foreseen that most parties will have difficulty printing the matrix or tables, the sender should also serve paper copies by U.S. mail, and indicate that in the electronic note.

6. Obtaining Up-to-Date Electronic Mail Addresses

The current service lists for active proceedings are available on the Commission's web page, www.cpuc.ca.gov. To obtain an up-to-date service list of electronic mail addresses:

- On the "Legal Documents" bar choose "Service Lists."

- Scroll through the "Index of Service Lists" to the number for this proceeding (or click "edit," "find," type in R001002, and click "find next").
- To view and copy the electronic addresses for a service list, download the comma-delimited file, and copy the column containing the electronic addresses.

The Commission's Process Office periodically updates service lists to correct errors or to make changes at the request of parties and non-parties on the list. Parties should copy the current service list from the web page (or obtain paper copy from the Process Office) before serving a document.

7. Pagination Discrepancies in Documents Served

Differences among word-processing software can cause pagination differences between documents served electronically and print outs of the original. (If documents are served electronically in PDF format, these differences do not occur, although PDF files can be especially difficult to print out.) For the purposes of reference and/or citation (e.g., at the Final Oral Argument, if held), parties should use the pagination found in the original document.

D. Intervenor Compensation

Any customer or representative of customers who intends to seek compensation should file and serve a notice of intent to claim compensation not later than 30 days after the prehearing conference in Phase I of this proceeding (Pub. Util. Code § 1804(a)(1)). The assigned ALJ may make exceptions to this deadline consistent with Section 1804. The ALJ will address each requesting party's eligibility to claim compensation in subsequent rulings.

E. Ex Parte Communications

In this ratesetting proceeding, Ex parte communications are permitted only if consistent with the restrictions set forth in Rule 7(c), and are subject to the reporting requirements set forth in Rule 7.1.

Findings of Fact

1. AB 117 requires the Commission to implement the procedure to facilitate the purchase of electricity by certain local entities on behalf of local citizens.

2. AB 117 identifies such entities as "Community Choice Aggregators."

Conclusions of Law

1. The Commission should open this rulemaking to fulfill specified aspects of AB 117 as set forth herein.

2. All jurisdictional electrical corporations should be made respondents to this rulemaking.

O R D E R

IT IS ORDERED that:

1. The Commission hereby initiates a rulemaking to implement the provisions of Assembly Bill 117 as set forth herein.

2. Pacific Gas and Electric Company, Southern California Edison Company, and SDG&E shall file opening comments on issues as set forth herein and other parties may file comments on October 22.

3. All jurisdictional electrical corporations are made respondents to this proceeding.

4. The Executive Director shall serve a copy of this order on all jurisdictional electrical utilities and all California cities and counties.

5. A workshop and prehearing conference is scheduled for October 29 at the Commission Courtroom in San Francisco, California and will commence at 10:00 a.m. The schedule described herein for this proceeding may be modified by the Assigned Commissioner or Administrative Law Judge.

This order is effective today.

Dated October 2, 2003, at San Francisco, California.

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

Commissioner Susan P. Kennedy, being necessarily absent, did not participate.

Attachment A
Reference Decisions and PG&E Rules, Schedules, and Forms

From the Procurement Proceeding (R.01-12-024)
D.02-10-062:
http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/_Toc23299394
From Section V "Resource Mix":

In modifying their procurement plans, the utilities should undertake a resource planning effort to include procurement from a mixture of different sources with various environmental, cost, and risk characteristics. Utilities fully responsible for meeting their customers' resource needs should plan among all of the following options: conventional generation sources (with a variety of types of ownership structures), renewable generation (including renewable self-generation), distributed and self-generation, demand-side resources, and transmission. In addition, utilities should plan to meet a reserve requirement. Each of these elements is discussed briefly below.

In making plans to procure a mixture of resources, the utilities should take into account the Commission's longstanding procurement policy priorities – reliability, least cost, and environmental sensitivity. While each of these priorities is important individually, they are also strongly interrelated. Increased reliability may increase procurement costs. Diversifying the resource mix may meet environmental priorities, but may also increase costs. Thus, the utilities should explicitly address these tradeoffs in their long-term procurement plans.

To assist with that process, we provide the following general guidance:

- Reliability now includes not just traditional concepts like adequacy of reserves, but also a recognition that it should include strategies to:

  Diversify the generation mix, and reduce reliance on fossil fuels
  Rebalance the IOU portfolio mix
  Address the reliability threat posed by aging power plants
  Address infrastructure security

- Least cost includes mitigating against an over-dependence on fossil fuels whose price is uncertain and can unexpectedly escalate, pulling electricity costs upward. Least cost also includes non-monetary attributes, as well as the time-differentiated production costs of power. Thus, flexible and reliable resource programs with relatively short development lead times (i.e., energy efficiency) can compete with traditional generation options for a place in the IOU resource portfolio. Capturing the time-differentiated costs of power also allows customers that place a higher value on low energy bills than on reliability to have programs available to them that also benefit the system (i.e., demand response programs).

- Environmental sensitivity encompasses not just traditional concerns over air quality impacts and aesthetic aspects of resource development, but a broader recognition that repowering or rebuilding on brownfields should be considered as substitutes to development of greenfields. In addition to the use of renewable technologies that must be included in the IOU plans consistent with the law and our mandate, the utilities should also include the environmental effects of repowering or rebuilding.

D.02-12-074
http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/22128.doc
Section H "Reserve Levels":

Based on our review and the comments filed, we find the 7% operating reserves level proposed by the utilities in their short-term plans to be adequate for 2003.

From the CRS Proceeding (R.02-01-011)
D.02-11-022
http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/20929.doc
Section IV, "Scope of Costs Subject to CRS:"

In compliance with D.02-03-055, charges must be imposed on DA customers sufficient to ensure that bundled service customers do not bear higher costs due to the migration of a significant number of customers from bundled to DA service between July 1 and September 20, 2001. This migration of DA load reduced the bundled customer base over which costs could be spread. Unless DA customers pay their respective share of such costs, bundled customers would have to make up the shortfall through higher bills, thus, resulting in a cost shifting.

By ALJ ruling dated March 29, 2002, parties were put on notice that the Commission would address in this proceeding "the full range of costs" necessary to avoid such cost shifting from DA to bundled PG&E customers. The ALJ Ruling defined the scope for determining surcharges, stating: "In order to ensure that the Commission is able to consider a fully compensable surcharge, a record must be developed that takes into account all possible cost responsibilities including but not limited to DWR purchase costs . . . attention will be focused on how such cost responsibility can be formulated." DWR purchases are the obligations of retail end-users within the service territories of the three electric utilities. (See Water Code § 80104.) In D.02-03-055, we noted that these purchases included those made by DWR on behalf of DA customers who returned to bundled service and also those bundled service customers who later entered into DA arrangements. In D.02-03-055, the Commission observed that: "There would be a significant magnitude of cost-shifting if DWR costs are borne solely by bundled service customers, and direct access customers are not required to pay a portion of these costs that were incurred by DWR on behalf of all retail end use customers in the service territories of the three utilities during a time when California was faced with an energy crisis."

DWR costs may be divided into two broad categories for purposes of assessing DA cost responsibility: (1) "historic" costs incurred between January 17, 2001 and the issuance of this decision, and (2) prospective costs (that will continue to be incurred under long-term DWR contracts from January 1, 2003 going forward until contract termination projected to be 2011. "Historic" costs may further be subdivided into costs incurred (1) between January 17, 2001 and September 20, 2001 and (2) between the suspension date of September 21, 2001 and December 31, 2002.

Among the other potential categories of additional costs noted in the ALJ ruling as being subject to DA CRS were purchased power costs from qualifying facilities (QFs) and costs related to the utilities' retained generation. In D.02 04 067, the Commission referenced the scope of additional non-DWR costs noted in the March 29, 2002 ALJ ruling, and expressly clarified D.02-03-055 to make clear that the CRS will take into account recovery of relevant non-DWR costs and that DA customers will be held responsible for such costs as required by AB 1X and other statutes (e.g., AB 1890). (See D.02-04-067, Ordering Paragraph (OP) 1e.) D.02-04-067 affirmed that nowhere in D.02-03-055 are DA customers relieved of their responsibility for AB 1890 transition costs, including those transition costs collected by SCE and PG&E during the rate freeze.

The determination of a DA CRS thus must take into account all relevant costs that would otherwise result in cost shifting from DA to bundled customers of customers of the three major IOUs. The scope of costs include those of DWR pursuant to AB1X and PG&E Retained Generation (URG)-related costs. We also take into account relevant companion proceedings where the Commission either has already adjudicated and adopted charges for DA cost responsibility or is in the process of adopting such charges for DA.

Section XV: CRS Mitigation: Capping or Levelizing CRS

In the absence of any positive evidence to the contrary other than subjective assertions of certain witnesses, we conclude that an initial cap set at the level of 2.7 cents/kWh represents an appropriately cautious starting point for a cap, particularly at the very beginning of instituting these charges. In the interest of caution, we find it prudent not to impose any abrupt change from the level the Commission has previously observed as a possibly reasonable cap value. An initial cap at this level will promote a bridge on continuity with the preliminary policy assessment on this issue that we made in D.02-07-032. Thus, we conclude that an initial cap of 2.7 cents/kWh is consistent with the overall goal of seeking to preserve the economic viability of the DA program.

D.02-12-045
http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/22038.doc
Direct Access Cost Responsibility Surcharge Section

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

D.03-05-034
http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/26070.doc
"Switching Costs" Decision
Section 2 "Discussion"

We shall adopt appropriate restrictions on DA customers' switching options using the framework described in this section. While the rules for the switching by DA customers should guard against placing any burden on bundled customers, the rules should also promote customer choice and economic efficiency. DA customers should not have the indiscriminate ability to come and go from bundled service without regard to the cost-shifting effects that may result. On the other hand, DA customers should not be unduly constrained from

selecting the most economically efficient service option, consistent with avoidance of cost shifting. We shall require existing DA customers who wish to switch to bundled service (other than for purposes of a temporary "safe harbor" while switching ESPs) to make the election for a minimum three-year period.
From Section 2b

"Applicability of Switching Rules to Large vs. Small Customers"

We find it reasonable to conclude that the movement of a few large customers with a disproportionately large load could have a greater impact on PG&E procurement than that of the same number of smaller customers. Yet, the difference appears to be a matter of degree rather than of kind. While there are differences in how PG&E procurement is impacted by large versus small customers, we do not believe that the record is sufficiently developed to quantify how those differences would translate into procurement decisions or size-specific rules. Moreover, certain restrictions that we adopt aimed at preventing incentives for arbitraging or other related activities are not necessarily a function of customer size.

Accordingly, we decline to adopt a different set of rules for large customers in contrast to small customers at this time. The rules we adopt in this order shall apply uniformly to all DA customers irrespective of size. In the proceedings that we order herein, we may consider further how customer size differences may be relevant in designing and implementing rules relating to DA switching between bundled and DA service on a prospective basis.

Energy Service Provider Agreement
Available only in pdf format.
http://www.pge.com/006_news/pdfs/esp_ag.pdf
Adopted in D.97-10-087, Appendix B.

Direct Access Rule 22 (PG&E and SCE)
http://www.pge.com/customer_services/business/tariffs/doc/ER22.doc

Direct Access Rule 25 (for SDG&E)
http://www.sdge.com/tm2/pdf/ERULE25.pdf

Schedule E-ESP
http://www.pge.com/customer_services/business/tariffs/doc/E-ESP.doc

SCHEDULE E-ESP—SERVICES TO ENERGY SERVICE PROVIDERS

APPLICABILITY: This schedule applies to energy service providers (ESPs) who provide direct access service to Customers, as defined in electric Rule 1 and Rule 22.

TERRITORY: The entire PG&E service territory.

RATES:

1. METER INSTALLATION. If an ESP requests that PG&E install a meter for its Direct Access Customer, the rates will be as set forth in Schedule E-EUS.

2. METER TESTING. If an ESP requests that PG&E test a meter for its Direct Access Customer, the rates will be as set forth in Schedule E-EUS.

3. METER REMOVAL. If an ESP requests that PG&E remove the existing PG&E meter, as set forth in Rule 22, the charge shall be as set forth in Schedule E EUS.

4. INSPECTION OF ESP-INSTALLED METERING EQUIPMENT. If PG&E inspects ESP-installed metering equipment pursuant to Rule 22 and the ESP Service Agreement, the charge shall be as set forth in Schedule E-EUS.

5. METER DATA MANAGEMENT AGENT (MDMA) SERVICES

a. Meter Reading Set-up charge, Per Meter $16.00. This charge applies to ESP’s when PG&E performs MDMA services to ensure ESP’s meter communication system is compatible with PG&E’s meter reading system.

b. MDMA services include data validation, editing and estimating to settlement quality form, data reads and data transfer to the MDMA Server If PG&E performs MDMA services for an ESP the charge shall be: per meter, per month $7.00 (R)(R).

c. Unscheduled Meter Read. Monthly meter, per meter read, per occurrence $12.00, Interval meter, telephone line retrieval, per meter read, per occurrence $25.00 Interval meter, on site data retrieval, per meter read, per occurrence $90.00.

6. CONSOLIDATED PG&E BILLING

a. Rate-Ready Billing. If an ESP requests that PG&E calculate the charge and bill the ESP's Direct Access Customers for the energy supply portion of the Customer's bill, the prices shall be:

(1) Billing Fee, per service account per billing cycle $0.70. If PG&E is billing the ESP's Direct Access Customers for the energy supply portion of the Customer's bill, the ESP may request that PG&E provide the following additional billing-related services at additional charges. The cost of these services will be as follows:

(2) Duplicate Bill Request from ESP, per bill per account $1.75

(3) Bill Adjustment, per adjustment per service account $6.50. An ESP may request PG&E to adjust a Customer's bill for reasons unrelated to PG&E's calculation of the ESP's charges, such as the following: ESP requested adjustment for reasons unrelated to the bill, such as goodwill gesture or promotional discount- Recourse adjustment as a result of dispute resolution Policy adjustment to satisfy a Customer's complaint

(4) ESP Rate Schedule Changes. An ESP may request to change the price on a particular rate schedule or change the rate schedule assigned to the customer.

(a) Price change, per rate schedule per change $5.00

(b) Customer rate change, per service account per change $5.00

(5) Rate-Ready Billing Set-Up Charges:

(a) Programming for consolidated billing set-up, per hour $72.00

(b) Programming for ESP's rate schedules, standard rate structure, per hour $72.00

(c) Programming for ESP's rate schedules, custom rate structure, per hour $85.00

(d) Programming for ESP's bill messages, per hour $72.00

(e) ESP bill message text, per character $1.50

(f) Central Processing Unit (CPU) charge for consolidated bill programming, flat fee per ESP $550.00

(g) Computer Storage Device, per service account being billed based on hourly interval metering data $70.00

b. Bill-Ready Billing. If an ESP requests that PG&E bill the ESP's Direct Access Customers for the energy supply portion of the Customer's bill as calculated by the ESP, the prices shall be:

1. Billing Fee, per service account per billing cycle $2.15

2. Duplicate Bill Request, per bill per account $1.75

3. Bill Adjustment, per adjustment per service account $6.50. An ESP may request PG&E to adjust a previously billed Customer's bill due to the following reasons:

   (a) Recourse adjustment as a result of a dispute resolution

   (b) Policy adjustment to satisfy a Customer's complaint

4. Bill-Ready Billing Set-Up Charges

   (a) Programming for consolidated bill set-up, per hour $72.00

   (b) Programming for ESP's bill message, per hour $72.00

   (c) ESP bill message text, per character $1.50

   (d) Central Processing Unit (CPU) charge for consolidated bill programming, flat fee per ESP $550.00

   (e) Computer Storage Device, per service account being billed based on hourly interval metering data $70.00

7. DELIVERY OF MANDATED NOTICES

A. Electronic transmission of text (electronic mail) for mandated notice no charge

B. For delivery of printed mandated notices to ESP's billing facility:

1. Up to 2 pounds, Express Mail - Next Day $15.00

2. Up to 2 pounds, Priority Mail - 2-3 Days $3.00. Prices for deliveries over two pounds will vary by zone, based on U.S. Postal Service rates. Prices above are based on 1998 U.S Postal Rates and are subject to U.S. Postal Service rate changes.

C. For delivery of printed mandated notices to ESP's billing facility: If an ESP performing Consolidated ESP billing requests that PG&E mail mandated notices to its customers, the following rates shall apply:

1. Programming charge, per hour $85.00

2. Materials and postage per mailing account $0.41

8. LATE PAYMENT FEE

A. If an ESP is performing Consolidated ESP billing and the bill to PG&E is not paid within 17 calendar days of transmittal of PG&E's customer charges, PG&E will assess late charges at the rate of one percent per month of the outstanding balance owed to PG&E, as set forth in the ESP Service Agreement.

Schedule E-EUS
http://www.pge.com/customer_services/business/tariffs/doc/E-EUS.doc
SCHEDULE E-EUS—END USER SERVICES

APPLICABILITY: This schedule applies to any Customer electing Direct Access (DA) or Hourly Pricing Option, as defined in electric Rule 1 and Rule 22.

TERRITORY: The entire PG&E service territory.

RATES: If PG&E performs any metering service for a Customer pursuant to Rule 22, the following charges shall apply:

1. Interval Meter-Cost

2. Per-Event Metering Service Charges

a. Metering Service Base Charge, per meter $90. This charge is incurred by the customer when PG&E goes to the meter to perform a DA metering service activity(ies). Any PG&E Meter Service Charges listed below that are incurred by the customer while PG&E is at the meter are added to this Metering Service Base Charge. Metering Service Charges:

b. Meter Installation, per meter $100. This charge is incurred by the customer each time PG&E installs an interval meter. This rate includes costs for the installation of the interval meter. This service does not include the interval meter cost, metering transformer material and installation cost, telecommunications equipment, installation or service costs. Meter removal, testing, and programming charges, described below, would also be charged for a typical meter installation.

c. Meter Removal, per meter $45. This charge is incurred by the customer each time PG&E removes an interval meter or a meter to be replaced by the interval meter. It includes costs for removal and processing of the existing meter.

d. Meter Test, per meter $60. This charge is incurred by the customer when PG&E tests the interval meter.

e. Meter Programming, per meter $25. This charge is incurred by the customer when PG&E programs the interval meter.

f. Meter Battery Change, per meter $30. This charge is incurred by the customer when PG&E replaces the interval meter battery.

g. Metering Inspection, per meter $55. This charge is incurred by the customer each time PG&E inspects the interval metering facility.

h. Metering Services Hourly Labor Rate $65. Metering services performed by PG&E which are not covered by the above service charges or any other PG&E fees or contracts will be charged this hourly rate, plus the Metering Service Base Charge described above, plus materials costs. Application of Per-Event Metering Service Charges: When PG&E performs any of the above services, the Metering Service Base Charge and applicable service charge(s) apply. For example, if an interval meter malfunction requires repair and testing of the meter, the customer would incur the Metering Service Base Charge, Unscheduled Metering Maintenance Charge, and the Meter Test Charge. Once the customer has communicated to PG&E that the interval meter site is ready for interval meter installation, if the interval meter site is not prepared at the time PG&E attempts to perform the interval meter installation, the customer will be charged the Metering Service Base Charge and the Metering Inspection Charge. If conditions at the DA meter site require an exceptional amount of material and/or time to perform meter services, the customer will be charged for the additional material cost and the hourly rate for the additional time. DA customers who purchase already-in-place PG&E-owned DA capable metering facilities will be required to pay the interval meter cost, the charges associated with meter installation, and labor and materials cost for any other components of the interval metering facility.

3. Meter Service Contract, per year per meter $145. Meter Service Contract is only available for interval meters for which PG&E has performed the interval Meter Installation of a PG&E approved meter. This charge is non refundable and will not be prorated. The Meter Service Contract includes services required to maintain the interval meter. The per-event service charges will not apply to customers served under a Meter Service Contract, with the exception of charges associated with meter installation, customer requested unscheduled meter tests, meter removal, and metering inspections.

4. Hourly Pricing Option MDMA SERVICES (The Hourly Pricing Option is suspended.)

a. Hourly Pricing Option Meter Reading Set-up charge, Per Meter $20.00. This charge applies to customers when PG&E performs MDMA services for Hourly Pricing Option, to ensure that all systems are updated so interval meter can be read.

b. Hourly Pricing Option MDMA services include data validation, editing and estimating to settlement quality form per meter per month $27.00.

5. Hourly Pricing Option BILLING (The Hourly Pricing Option is suspended.)

a. Hourly Pricing billing set up per Service Account $20.00

6. CONSUMPTION DATA. If PG&E provides historical Service Account specific consumption data pursuant to Rule 22, the following charges shall apply per account per request free up to two (2) times per year, $40 per request per service thereafter.

Schedule E-DASR
http://www.pge.com/customer_services/business/tariffs/doc/E-DASR.doc
SCHEDULE E-DASR—DIRECT ACCESS SERVICES REQUEST FEES
APPLICABILITY: This schedule applies to energy service providers (ESPs) who provide direct access service to Customers, as defined in electric Rule 1 and Rule 22.

TERRITORY: The entire PG&E service territory.
RATES:

1. DIRECT ACCESS SERVICE REQUEST (DASR) CHARGES:

a) Switching. An ESP submitting a DASR as required by the ESP Service Agreement will be charged per account per DASR submittal. This charge applies to all accepted DASRs for switches from bundled service to DA, switches between ESPs, switches in metering agents, and switches in billing agents. This fee does not apply to rejected DASR's DASR Charge, per account per DASR submittal no fee

b) Billing Set-Up

1. Consolidated PG&E Billing Set Up refer to Schedule E ESP2) Consolidated ESP Billing Set Up refer to Schedule E-ESP3) Separate Billing Set Up no fee

c) Billing Option Switches

1. Consolidated ESP to Consolidated PG&E Billing
2. Consolidated PG&E to Consolidated ESP Billing
3. Separate Billing to Consolidated ESP Billing
4. Separate Billing to Consolidated PG&E Billing
5. Consolidated ESP to Separate Billing
6. Consolidated PG&E to Separate Billing per account per accepted DASR submittal no fee

2. CONSUMPTION DATA. If PG&E provides historical Service Account specific consumption data pursuant to Rule 22, the following charges shall apply per account per request free up to two (2) times per year, $40 per request per service account thereafter.

(END OF ATTACHMENT A)