Decision 04-12-046 December 16, 2004

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Portions of AB 117 Concerning Community Choice Aggregation.	Rulemaking 03-10-003 (Filed October 2, 2003)

(See Appendix A for List of Appearances.)

ORDER RESOLVING PHASE 1 ISSUES ON PRICING AND COSTS ATTRIBUTABLE TO COMMUNITY CHOICE AGGREGATORS AND RELATED MATTERS

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Appendix B - Assembly Bill 117

ORDER RESOLVING PHASE 1 ISSUES ON PRICING AND COSTS ATTRIBUTABLE TO COMMUNITY CHOICE AGGREGATORS AND RELATED MATTERS

This order resolves outstanding issues in Phase 1 of this proceeding, which addresses costs and other related matters relevant to Community Choice Aggregators (CCA) and in order to implement the provisions of Assembly Bill (AB) 117 (2002 Stats., ch. 838) that would enable CCAs to procure power for their local residents and businesses.

I. Summary and Background

CCAs are governmental entities formed by cities and counties to serve the energy requirements of their local residents and businesses. The state Legislature has expressed the state's policy to permit and promote CCAs by enacting AB 117, which authorizes the creation of CCAs, describes essential CCA program elements, requires the state's utilities to provide certain services, and establishes methods to protect existing utility customers from liabilities that they might otherwise incur when a portion of the utility's customers transfer their energy services to a CCA.

Cities and counties have become increasingly involved in implementing energy efficiency programs, advocating for their communities in power plant and transmission line siting cases, and developing distributed generation and renewable resource energy supplies. The CCA program takes these efforts one step further by enabling communities to purchase power on behalf of the community.

Today's decision is the first major step toward implementing that portion of the CCA program that would facilitate energy procurement activities by cities and counties. Today's decision constitutes the beginning of our implementation of AB 117. In this implementation, we have fashioned a program that is consistent with our expressed policies with regard to resource planning, utility ratemaking and cost recovery generally. This approach to the program will protect bundled utility customers who do not have the option to transfer to a CCA from the possible cost impacts of CCA programs.

This order by itself does not resolve all issues, even those originally anticipated for Phase 1 in this proceeding. Unfortunately, the record does not provide the type of information required for final resolution of many of the cost allocation issues that are the subject of this phase of the proceeding. This order does, however, take the program as far as possible with the limited information we have by adopting interim CCA charges and service protocols.

We hope this decision provides the type of guidance CCAs and prospective CCAs will need in determining whether to pursue energy procurement efforts in advance of our final order in Phase 2. The order should also provide some guidance to the parties about how we envision the CCA energy procurement program in the broadest sense, and the costs that CCAs will have to incur as customers of and partners with the utilities.

This order adopts the following:

- Department of Water Resources' (DWR) methodology for estimating the cost recovery surcharge (CRS), which will allow the utilities to recover from CCAs the costs of DWR bonds and contracts, utility power procurement contracts and other items in a way that remaining bundled utility customers are indifferent to the CCA program;
- A temporary CRS in the amount of \$.020/kWh, which will be trued up in 18 months or sooner, if final utility estimates of CRS are 30% lower or higher than \$.020/kWh, and thereafter will be trued up annually;
- Principles for setting prices for utility services offered to CCAs;

- Ratemaking and cost allocation principles for utility services offered to CCAs, implementation costs and the CRS;
- A method to allocate amounts related to the subsidy for baseline customers;
- An exception from the CRS for certain load attributable to Norton Air Force Base in the event that customers at Norton are served by a CCA;
- Requirements for and conditions under which CCAs can acquire customer information from utilities needed to manage energy procurement by CCAs;
- Application of AB 117 as it relates to CCA program phase-ins, boundary metering and the use of CCA-specific load profiles.

II. Procedural Background

The Commission opened this rulemaking on April 27, 2004 to implement certain provisions of AB 117 (Chapter 838, September 24, 2002), which added Pub. Util. Code §§ 218.3, 331.1, 366.2, 381.1, and 394.25 and permits local governments the opportunity to aggregate energy procurement on behalf of the citizens and businesses in their communities.[1]

AB 117 involves Commission-jurisdictional utilities by requiring them to continue to provide distribution, metering and billing services to the CCA's energy customers, among other things. AB 117 also directs the Commission to ensure that the utilities are able to recover certain costs, including those

[1] 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.) 01-08-028.

associated with energy contracts signed by the state's DWR and the costs of providing ongoing services to CCAs and their customers.

Following a prehearing conference on November 26, 2003, and with the agreement of all active parties, the Commission bifurcated the proceeding so that the Commission would first consider issues relating to certain utility costs that would be assumed by CCAs and later consider issues more concerned with transactions between CCAs, utilities, and energy customers.

A key issue in this proceeding is the level of the cost responsibility surcharge (CRS), which would permit the utilities to recover the costs of certain energy contract commitments. Utilities are concerned that the CRS be set so that they recover related costs. Utilities also want assurance that they are able to recover other discretionary costs incurred to implement and facilitate the CCA program. Entities that might become CCAs state that the level of the CRS and other utility charges will determine the viability of CCAs. Some state that the existing CRS exception for baseline residential Direct Access (DA) customers should also be applied to CCA customers.

Several parties also suggested that CCA information requirements should be addressed sooner rather than later. Parties generally agreed, however, that modifying Rule 22 and Rule 25 to govern transactions and operations of CCAs and utilities is an exercise that should follow resolution of cost issues.

Consistent with the parties' agreement and the record developed in hearings, this Phase I order addresses the following issues:

a. The cost responsibility surcharge – cost elements that should be included in this surcharge in fulfillment of AB 117; allocation of responsibility for the costs and whether they are nonbypassable;

b. CRS exception for baseline residential customers – whether the utilities should pass along these subsidies to CCA customers and, if so, how to accomplish that;

c. Utility transition, implementation and transaction costs – estimating, allocation and setting cost allocation mechanisms for creating and maintaining the CCA program;

d. Meter, billing and distribution costs;

e. Utility customer information – information CCAs and prospective CCAs need to determine viability of CCA service and promote good customer service and reliability costs.[2]

The Commission held hearings on these issues in June 2004. Parties that filed briefs are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas and Electric Company (SDG&E), Office of Ratepayer Advocates (ORA), Local Government Commission Coalition (LGCC), California Clean Energy Resources Agency and the City of Victorville (CalCLERA), Local Power, the County of Los Angeles and the City of Chula Vista (LA/CV), City and County of San Francisco (CCSF), Inland Valley Development Agency (IVDA), Toward Utility Rate Normalization (TURN), ElectricAmerica, and the King's River Conservation District (KRCD) filed briefs.[3] The California Department of Water Resources provided extensive information about the cost of

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[2] Phase 2 in this proceeding will address the following issues:

1. Customer notices required of utilities and CCAs;
2. Customer protections and switching protocols;
3. Operational protocols and load balancing;
4. Billing, metering and distribution services;
5. Reentry fees and switching fees;
6. CARE – discounts to low-income customers; and
7. Other unresolved issues.

[3] Occasionally, this order refers to parties that are "CCAs or prospective CCAs." In so doing, the order is referring to all or some subset of LGCC, CalCLERA, LA/CV, CCSF, IVDA, Electric America and KRCD.

the state's electric contracts and models for estimating associated liabilities, and submitted a memorandum suggesting how the Commission should implement the cost responsibility surcharge.

This phase of this proceeding was submitted on July 23, 2004 when reply briefs were filed.

III. Implementation and Transaction Costs

AB 117 addresses how the utilities would recover the costs they incur to accommodate the CCA program and provide related services to CCAs. Section 366.2(c)(17) provides general guidance about how the utilities may recover costs associated with CCA program implementation and services.

> "An electrical corporation shall recover from the [CCA] any costs reasonably attributable to the [CCA], as determined by the Commission, of implementing this section, including, but not limited to, all business and information system changes, except for transaction based costs as described in this paragraph. Any costs not reasonably attributable to a [CCA] shall be recovered from ratepayers, as determined by the Commission. All reasonable transaction-based costs of notices, billing, metering, collection and customer communications or other services provided to an aggregator or its customer shall be recovered from the aggregator or its customers on terms and at rates to be approved by the Commission."

The section refers generally to "implementation" costs and a subset of implementation costs called "transaction" costs, which it specifies are those costs related to billing, metering, customer communications and other customer costs. We infer from the language of the section that implementation costs are those associated with setting up the CCA program, and the infrastructure required to maintain and operate it. Such costs might include those associated with computer programming and data base development, and other overhead costs.

Implementation costs would include all costs except those that are identified as "transaction" costs in AB 117, such as metering and billing costs conducted on behalf of an individual CCA. We address transaction costs and implementation costs separately below.

In general, we consider how to allocate and permit recovery of CCA program costs consistent with the statute. Where the statute provides the Commission with discretion, we treat CCAs as customers who are buying services from the utilities. With that in mind, we apply ratemaking and cost allocation principles that are comparable to those applied to other utility customers. Where there exist special circumstances or conditions that favor different treatment of CCA costs, we make exceptions to this general rule, consistent with AB 117.

A. Allocation of Implementation Costs Between Ratepayers and Individual CCAs

The utilities and prospective CCAs differ in their interpretation of AB 117 with regard to allocating AB 117 implementation costs among CCAs, their customers and utility ratepayers more generally. "Implementation costs" in this context are those costs of establishing the CCA program and serving CCAs that are not identified as "transactions costs" pursuant to Section 366.2(c)(17).

SCE and SDG&E argue that CCAs and their customers must assume all CCA implementation costs, citing the portion of AB 117 that requires the electric utility to "recover from the CCA any costs reasonably attributable to the CCA, as determined by the Commission, of implementing this section." Assuming there are some implementation costs that are not directly attributable to a single CCA but are reasonably allocated to CCAs, SCE proposes two models for allocating costs among CCAs. The first would allocate all costs to the first CCA and provide a refund to that CCA when subsequent CCAs pay their proportional share. The second would estimate the number of CCAs and establish charges accordingly. SCE would true-up the mismatch between estimated and actual revenues, and subsequently refund or charge CCAs accordingly. SDG&E argues that AB 117 does not permit cost-shifting of any type and that imposing implementation costs on the general body of utility ratepayers would represent cost-shifting.

PG&E would allocate "a minimum level" of "basic implementation costs," such as computer programming, to all ratepayers. It would charge "exceptional" implementation costs to individual CCAs. PG&E identifies these services as customized to the CCA and argues that it is not required to provide such services. ORA concurs with PG&E to the extent that it has concerns that startup costs could become an insurmountable barrier to the creation of CCAs. ORA argues that the program generally will benefit all ratepayers because they may at some point have an opportunity to choose service from a CCA. Accordingly, ORA proposes that utilities' ratepayers "loan" CCAs the costs of upfront funding, to be repaid in increments when CCAs initiate service during each open season.

CCSF, LA/CV, and King's River concur with PG&E that some costs should be allocated to all ratepayers, citing Section 366.2(c)(17) which states "Any costs not reasonably attributable to a CCA shall be recovered from ratepayers, as determined by the Commission."

Discussion. AB 117 requires CCAs or their customers to assume any costs incurred on behalf of individual CCAs. Based on the plain language of the statute, we find that those costs which may be identified as being incurred on behalf of a CCA should be assumed by the CCA and its customers. Those costs that cannot be associated with an individual CCA may be allocated to all ratepayers, at the discretion of the Commission. If the Legislature intended that no CCA program implementation costs be allocated to all ratepayers, we must assume that it would not have required that utility ratepayers assume program costs "not reasonably attributable to a CCA." The choice of the phrase "a CCA" in this context also supports the CCAs' interpretation of the statute. If the Legislature had intended that the general body of ratepayers assume no implementation or transaction costs, this phrase would have said "not reasonably attributable to CCAs." That construction, however, would appear superfluous because the statute does not address the treatment of costs incurred by entities other than CCAs.

The statute gives the Commission discretion to establish which costs should be borne by utility ratepayers and we find that the assumption of implementation costs by such ratepayers is not "cost-shifting." Our interpretation of Section 366.2(c)(17) reflects our view that, while AB 117 would limit the cost liability of customers remaining with the utility, it recognizes that some program costs could not reasonably be assumed by a single CCA without creating insurmountable practical problems or barriers to entry that the statute probably did not intend.

The question then is which costs are attributable to individual CCAs and their customers and which are more appropriately allocated to utility ratepayers. We agree with PG&E that individual CCAs should not assume the costs of developing the CCA program's basic infrastructure. The CCA program is supported by the state's legislature as good public policy and one that will promote the state's interests. For that reason alone, we do not consider future CCAs and their customers as the sole beneficiaries of the program. We also wish to avoid the practical problems associated with isolating infrastructure costs and allocating them to individual CCAs as SCE proposes, for example, by charging early CCAs the bulk of the costs and refunding them later. This formula is complex and would present a significant artificial barrier to the creation of CCAs. ORA's suggestion that utility ratepayers "loan" CCAs the costs of program startup is also untenable because of its complexity and the uncertainty it creates for CCAs. For these reasons, the costs of developing the CCA program's infrastructure should be assumed by all customers, the CCA's and the utility's.

We adopt PG&E's proposal to allocate basic startup implementation costs to all customers and to charge individual CCAs the costs of specific specialized services. We will direct all three utilities to design tariffs accordingly. The utilities should account for these costs as they would any infrastructure costs, whether in capital accounts or expensed. We will address the issues of cost recovery from ratepayers more fully in a subsequent section of this order.

B. Transaction Costs

Section 366.2(c)(17) requires that "all reasonable transaction-based costs of notices, billing, metering, collections, and customer communications or other services provided to an aggregator or its customers" be recovered from the CCA or its customers in rates.

The utilities presented a list of the types of costs that should be recovered from CCAs or their customers and also the methods for determining the related rates. They did not propose final specific cost recovery from ratepayers in this phase of the proceeding, seeking to develop those cost allocations in Phase 2.

The utilities generally propose an "incremental costing methodology" to base charges to individual CCAs for tariffed services. This methodology would recognize the additional costs the CCAs impose on the system. The utilities propose that all transaction costs, including those that might be incurred for a single service, be charged directly to individual CCAs. In some cases, they propose to charge CCAs for services for which they are already reimbursed in existing rates. In those cases, SCE and PG&E would account for CCA revenues as "Other Operating Revenue" and subtract them from the utility's revenue requirement.

Other parties generally agreed with the incremental costing methodology in concept but raised concerns about the ways the utilities applied the principle. LGCC suggests the Commission order the three utilities to develop a consistent and transparent methodology. To that end, LGCC would have the utilities prepare a joint exhibit that describes (1) services to be provided; (2) the details of utility proposals for providing the services; and (3) costs related to current tariffs for similar services to direct access customers. LGCC proposes that the actual level of service charges be adopted in Phase 2 of this proceeding. LA/CV states that, as a matter of fairness, the utilities should not be able to charge for any service for which existing customers do not currently pay. They also suggest that tracking and monitoring associated costs and changing rates will present practical difficulties.

CCSF argues that the utilities' cost estimates must recognize the operational cost savings that the utilities will realize from CCA formation and operation. CalCLERA proposes that the utilities' rates recognize the more global benefits of CCAs to California and its customers associated with reduced risk, reduced wholesale power costs, and economic development.

Related to the utilities' costing methodology is the issue of whether to apply existing charges for direct access customers to CCAs and their customers for identical transactions and services. The utilities argue that these charges should not be applied because they are out of date, having been adopted in l997. Other parties argue that they are reasonable for the time being. If necessary to avoid delay of CCA program implementation, LGCC and King's River suggest utilities apply direct access tariffs in the interim. ElectricAmerica presents similar arguments and believes the Commission should find a way to credit CCAs for the fees they have paid the utilities to develop information infrastructure.

Discussion. We adopt the utilities' incremental costing methodologies because conceptually those methodologies would protect bundled customers from cost-shifting, prevent the utilities from realizing unreasonable profits from the CCA program and conform to the statute's requirement that costs associated with a CCA be charged to a CCA. Although we adopt the costing methodologies the utilities propose, we do not apply them as they would in all cases. Costs for which the utilities are already reimbursed in the utility revenue requirements shall not be charged to CCAs at this time. For example, utilities today recover the costs of the billing system and customer service calls. If CCAs were charged for these services, the utilities' shareholders would receive a windfall except to the extent the customer's bills reflect only those additional costs imposed on the system by the CCAs. The utilities' proposal to implement the charges now and credit "other operating revenues" does not cure this problem prior to a general rate case order. Because general rate cases incorporate "other operating revenues" into the revenue requirement on a forward-looking basis, the utilities would receive a windfall between the time they implement the CCA charges and the time of the next general rate case order. If the utilities wish to propose to unbundle CCA services for which they are already reimbursed, such as customer service inquiries, they may propose to do so in their future general rate cases.

Until that time, their CCA tariffs should not include any costs for which the utilities are already reimbursed.

As CCSF and King's River suggest, we also expect the utilities' fees to recognize the operational cost savings that might occur with CCA formation. To the extent that the utilities' cost methodologies really do reflect incremental costs, their proposed fees will incorporate program cost savings. We are not prepared, at this time, to quantify the benefits of the CCA program on the state's energy or economic infrastructure, as CalCLERA proposes. While there may be such benefits, we do not have before us an adequate record to develop an associated methodology and their estimation would be highly speculative. Parties may raise this issue in the future if they are able to present reasonable methods for estimating these benefits, supported by an adequate record.

Unfortunately, and in spite of the Commission's intent, we do not have a complete record to adopt final charges in this phase of the proceeding. The parties representing prospective CCAs agreed to bifurcate this proceeding at the urging of the utilities with the understanding that to do so would provide them with an early understanding of the charges they would face as CCAs and in order to determine whether it would be worth their time and resources to proceed to Phase 2. In spite of this understanding, the utilities have stated they have not had the opportunity to create the tariffs anticipated in R.03-10-003. They have now had a year to create those tariffs since the initiation of this proceeding and another year prior since the Governor signed AB 117. By this order, we direct the utilities to submit proposed tariffs consistent with this order no later than 30 days following the effective date of this order for consideration in Phase 2 of this proceeding.

In the meantime, we will not suspend progress toward implementation of the CCA program to accommodate the utilities' delay in presenting final tariff proposals. Instead, we direct the utilities to use existing direct access tariffs until their CCA tariffs are approved and final as suggested by several parties, including LGCC, King's River and ElectricAmerica. We believe that the charges in direct access tariffs provide a reasonable proxy for costs while we finalize CCA charges.

In sum, we adopt the utilities' proposed costing methodologies for those services which are not already included in the utilities' rate base. Any service for which the utility is already reimbursed, at any level, shall not be included in CCA tariffs at this time. The utilities are ordered to submit and serve tariffs consistent with this order within 30 days of the issuance of this order. We intend to approve final tariffs in Phase 2 of this proceeding and direct the utilities to apply the direct access CRS tariffs in the meantime.

We discuss several specific tariff proposals in following section.

C. Specific Transaction and Implementation Costs

1. Incremental Billing Costs

SCE and SDG&E state they will have incremental billing costs because they will have to receive usage and other information from the CCA, then bill the customer on a separate page from the utility's bill, then remit the payments to the CCA. CCSF proposes that the utilities unbundle billing services so that inquiries about billings are charged separately, as with direct access customers. CCSF also proposes that when an inquiry is required to reconcile a utility error, the CCA should not be charged.

Discussion. We agree with the utilities that the CCA program will impose incremental billing costs beyond those that are already included in utility revenue requirements. The utilities should estimate those costs consistent with this order and propose a recovery that does not include the costs of mailing the bill to the customer, since those costs are already recovered in existing customer bills. SCE notes that the utilities may incur additional postage costs for including CCA information in utility bills. In such cases, we agree with the utilities that CCAs should assume this incremental cost.

We also adopt CCSF's proposal for unbundling billing processing fees. We agree that a CCA should not be required to pay for a service that it may choose not to use and should not incur fees for billing errors attributable to the utility. We expect to explore this issue in more detail in Phase 2 of this proceeding as we consider issues relating to program operation and administration.

2. Incremental Call Center Costs

SCE states it will incur incremental costs relating to helping customers at its call centers. CCSF objects to the utilities' proposals to charge for such calls since other customers do not pay individually for those calls. CCSF proposes these costs be assumed by ratepayers as a group, as they are currently.

Discussion. We are not convinced that the CCA program will significantly increase the number of calls to utility call centers. Because the utilities already recover the costs of customer call center operations in customer bills, and assuming CCA customers do not call the utilities more frequently than they would as utility bundled customers, the utilities are not penalized if they do not charge CCAs for CCA customer calls. To the extent that the utilities are able to demonstrate in future general rate cases that a CCA program has caused incremental costs to operate the call centers to address CCA business matters, we will consider approving an associated fee at a later time. In that case, we would expect the utilities to make corresponding reductions to the revenue requirement for call center services to bundled customers. In addition, fees to CCAs should not include the costs of calls that concern utility services. While CCAs should ultimately pay for the services they or their customers receive, they should not be charged for calls that involve utility distribution, transmission, or other utility services.

Prior to the utility's general rate case, the utility may track and recover incremental call center costs, should they occur, by establishing an "800" number dedicated to CCA customer service calls and billing the individual CCA separately for those calls, as SCE proposes. This separate call system will help assure that CCAs do not inadvertently pay for calls about utility services while allowing the utilities to recover incremental costs of the CCA program.

3. Incremental Costs for Opt-Out Provision and Re-entry Fees

SCE and SDG&E believe they will incur incremental costs relating to the "opt-out" provision of AB 117, that is, the option for utility customers to remain bundled utility customers rather than transfer to the CCA. SCE argues that neither its shareholders nor its remaining ratepayers should assume liability for those costs. ORA suggests the initial implementation costs for this part of the program should be assumed by the general body of utility ratepayers. After that, ORA argues that utility shareholders should assume the cost of luring a customer back to its bundled service. ORA believes it would be "fundamentally unfair and against the basics of a competitive market place to make a CCA pay its competitor's cost of taking away its customer."

CCSF proposes that utility ratepayers assume the cost of processing the opt-out provisions of the CCA program, while recognizing that the opt-out notification costs are allocated to CCAs by the statute. CCSF also believes it is inappropriate for the utility to charge the CCA an opt-out fee for the cost of transferring a CCA customer back to the utility. LA/CV makes similar points.

Discussion. Start-up costs associated with implementation of the opt-out provision should be assumed by CCAs individually because such costs are primarily incurred to implement each CCA program and are not infrastructure development costs. The costs the utilities incur to create, mail or otherwise facilitate a CCA's notification shall be included in utility tariffs.

As CCSF, LA/CV and ORA suggest, the cost of transferring a customer from the CCA to the utility should not be assumed by the CCA. With regard to "re-entry" fees referred to in R.03-10-003, we find that the utility may charge the customer for the transfer back to the utility once that customer is again a bundled utility customer. The re-entry fee as we use the term here refers to the utility's administrative cost of making the transfer. We will address how to calculate and allocate the cost of incremental procurement and reliability in Phase 2 of this proceeding. As a general matter, the CCA should not have to assume the cost of activities that ultimately deprive the CCA of a customer.

SDG&E suggests utility customers receive a notice of the CCA program in advance of the CCA's notice. These preliminary notices would give customers information about the program and the release of customer information. We agree this notice might provide important information to the customer about potential changes in service. However, we do not believe the CCA should pay for a notice that is not required by the statute and is sent at the utility's discretion. Therefore, if the utility chooses to send such a notice, the associated cost should be assumed by the general body of utility ratepayers as start-up costs and consistent with the Commission's treatment of all customer notices regarding changes in markets and rules, and utility programs and services. If a utility chooses to send such a notice, it shall receive review from the Commission's Public Advisor office of its draft notice to assure the notice may not be misconstrued as a marketing tool for utility services. The notices shall provide basic information to customers explaining what the CCA will do, and how it may affect relevant customers and their service options.

In sum, we herein allocate the start up costs for opt-out provisions to each CCA. CCAs shall also assume all costs associated with their own opt-out notices. The utilities shall not charge the CCA for the CCA customer's transfer back to the utility once the customer becomes a utility customer. The utilities may charge these customers a re-entry fee for such a transfer, once they again become a utility bundled customer. The costs of customer re-entry associated with procurement and other liabilities will be considered in Phase II of this proceeding.

4. "Detailed Processes" Outlines

SCE, PG&E, and SDG&E each developed an initial proposal of "detailed processes" required to implement the CCA program. The utilities discussed these outlines with all interested parties at Commission workshops conducted prior to evidentiary hearings and were subsequently included in the utilities' testimony. SDG&E asks the Commission to adopt the specific processes in Phase 1 to facilitate Phase 2 of this proceeding, where the Commission will be addressing terms of service and operational issues. Except as discussed in other sections of this order, no party took issue with the content of these outlines.

The detailed processes outlines are useful explanations of internal procedures and form a reasonable foundation for considering cost and processing issues. Unless stated otherwise in other parts of this order, we state our intent to use them as foundation for future CCA program tariffs and further development of operational issues in Phase II of this proceeding.

5. Recovery of Implementation and Transactions Costs

The utilities propose accounting mechanisms to ensure that they are made whole for the costs they incur to implement AB 117. SCE proposes a memorandum account and seeks funding for CCA program implementation in advance. PG&E would include a forecast of CCA costs in its distribution revenue adjustment mechanism with a true-up at a later date, which is substantially similar to SCE's proposal. LGCC suggests the Commission adopt a forecast of utility costs and hold the utilities to that amount.

PG&E and SCE propose to update transaction costs by way of advice letters, which would be deemed automatically effective within 40 days unless protested, or suspended by Commission staff.

Local Power and other parties oppose upfront funding of implementation costs, arguing that CCAs are captive customers of the utilities for many services and should not be subjected to extraordinary financial burdens.

Discussion. We agree with the utilities that, for initial program costs prior to general rate case review, implementation costs should be recoverable dollar-for-dollar. We refer here only to implementation costs that would be recovered from the general body of utility ratepayers and ultimately subject to review in general rate cases. We take this step to permit the creation of balancing accounts only for the period prior to each utility's next general rate case. For subsequent periods, the utilities should treat CCA costs like those incurred for any other customer service or operation cost and include the amount in the general rate case revenue requirement.

To the extent the utilities provide services to CCAs, CCAs would be customers of the utilities and, consistent with our treatment of the operational costs of serving other customers, the utilities should assume some risk for serving them and be able to reap the benefits of cost savings they implement between general rate cases. Moreover, CCAs should not have to assume liabilities for infrastructure development in advance. Such a requirement would be unprecedented in our treatment of utility customers and is unjustified here.

Consistent with the foregoing discussion, the utilities shall establish balancing accounts for the initial period of program implementation and prior to their next general rate cases. As part of their respective general rate cases, they should recover those costs and propose forward looking CCA implementation and infrastructure costs as part of their revenue requirements, consistent with treatment of similar costs for other types of customers.

For transaction costs, we will not permit the utilities to develop balancing accounts and instead order them to develop tariffs for transaction costs. Rates for recovery of transaction costs should be forecast based on incremental costs and, as the utilities propose, imposed on CCAs directly and included in tariffs. CCAs, like all customers, are entitled to some expectation that their charges will be predictable and subject to review by the Commission. As we suggest in our discussion of implementation costs, we are concerned that open-ended balancing accounts and true-ups will undermine incentives for cost containment by the utilities and corresponding opportunities to make a reasonable rate of return on the provision of related services. Moreover, as LA/CV suggests, we wish to avoid constant litigation concerning the level of dozens of possible tariffed charges, which would be expensive for the utilities, the CCAs and the public. The utilities should track their transaction costs to justify prospective changes to charges included in CCA tariffs, which we will consider in general rate cases. We will not consider changes to CCA tariffs between general rate cases or, where general rate cases are deferred, more than every three years. In the latter case, we will consider utility applications for CCA changes. Between general rate cases, utilities may file advice letters if they wish to propose changes in CCA tariffs to components other than increases to existing rates, or for new services or to reflect changes in the industry or CCA program operation.

IV. Cost Responsibility Surcharge

Section 366.2(d)(1) of AB 117 provides that the costs associated with CCA's procurement of power for local residents and businesses must not require remaining utility customers to assume additional costs, that is, those power procurement costs that would be unavoidable when the utility loses customers to the CCA. In that way, AB 117 anticipates "ratepayer indifference" to the CCA program. No party disputes this principle, although how to calculate and implement the CRS raises some complex and somewhat controversial related issues, discussed below.

The Commission has already adopted such surcharges for other types of customers who stop taking power from the utility, including those who depart from all utility services and generate their own power, direct access customers and departing load customers of municipal utilities that reduce their demand from the utility in favor of other power procurement resources. Where possible, we apply the lessons learned and the policies adopted in those cases to the CRS we adopt for CCAs.

A. The CRS Model

All parties agree that AB 117 requires the CCA CRS to include a variety of costs incurred on behalf of CCA customers prior to their transferring to the CCA. Such costs include (1) costs associated with power contracts and bonds entered into by DWR during the energy crisis; (2) utility power costs, including those of utility retained generation, purchased power and other commitments in approved resource plans; and (3) CTC and historic revenue undercollections and credits applicable to the customer at the time the CCA transferred the customer. No party disputes these cost elements.

The CRS model that was the basis for most discussion was presented by DWR and operated by Navigant Consulting. In general, DWR recommends that the Commission adopt for CCAs its CRS methodology, which is referred to variously as "CCA-in/CCA-out," "total portfolio" model or the "indifference fee" approach. This methodology analyzes the liabilities that would otherwise be assumed by bundled utility ratepayers when the CCA begins serving local customers. Those liabilities would then be incorporated in the CRS so that bundled utility ratepayers are not penalized by the utilities' loss of energy customers. This methodology is the one adopted in D.02-11-022 for direct access customers. It is a forecast of those DWR power costs that are assumed by PG&E, SCE and SDG&E and that are expected to exceed market prices. The CRS will fluctuate according to changes in market prices, that is, as prices goes up, the CRS and related liabilities will fall. Under AB 117, these power cost liabilities must be incorporated in the CRS so that bundled utility ratepayers do not assume liabilities relating to the utilities' loss of energy customers to CCAs. The methodology DWR presented in this proceeding is the one adopted in D.02-11-022 for direct access customers.

In a memorandum to the Commission dated July 9, 2004, DWR presents several recommendations on how to implement the CRS in a way that prevents cost-shifting and promotes administrative simplicity and revenue certainty, where applicable. It did not present a final proposed cost allocation in this proceeding but agrees to work with the Commission and utilities following its resolution of outstanding controversies in how to set the CCA CRS.

The utilities and most parties support DWR's "CCA-in/CCA-out" methodology and truing up the difference between the forecast and actual costs annually. SDG&E recommends removing from DWR's illustrative calculation SDG&E's CTC and bond charge, nonbypassable components applied to the direct access customers that are not relevant to the calculation of a CRS for CCAs. SDG&E also argues against a cap on the CRS, which the Commission applied to direct access customers.

Discussion. No party challenges the utilities' proposal with regard to the types of costs that should be included in the CRS or even the methodology DWR presents. The methodology has been subject to considerable scrutiny in other proceedings and it is reasonable to adopt it here.

The CCA CRS should be calculated separately from the CRS for direct access customers to reflect the utilities' concurrent power purchase liabilities, which may differ from those incurred in previous years. We direct the utilities to impose the CRS on new customers as well as existing customers because both would have been required to assume those liabilities if they had taken service from the utility rather than the CCA. In addition, the CRS should incorporate any refunds to or credits associated with the accounts, bond charges and power purchase contracts that are subject to CRS treatment, which SCE proposes and no party opposes. Consistent with our view that the CRS for each CCA should reflect the costs incurred on behalf of CCA customers, the CRS for each CCA in each period should reflect the cost savings or refunds associated with commitments made on behalf of those CCA customers. The CRS should not include any avoidable costs, such as ISO charges for ancillary services.

B. CRS "Vintaging"

The parties addressed whether and how the CRS should change at regular intervals to reflect changes in utility portfolios that might increase or reduce power purchase liabilities, an exercise the parties refer to as "vintaging." The CCA would then assume liability going forward for only those DWR and utility liabilities that were current at the time the CCA began its operations. The utilities and other parties generally agree that vintaging this portion of the CRS is appropriate to reflect the utilities' prevailing power cost liabilities and to assure CCA customers pay for those resource commitments, and only those commitments, that were incurred on their behalf. PG&E would defer vintaging until there has been more progress in resource planning policies and practices.

We agree with the parties that vintaging the CRS for each generation of CCA would provide equity between CCAs because none would have to assume the stranded power costs incurred on behalf of another. A vintaged CRS may also provide the appropriate forum for updating utility power liabilities that are incurred in the future and would be otherwise unrecoverable if customers are served power by a CCA. On the other hand, we are concerned that vintaging as we understand it may create a complex regulatory process by requiring the Commission and the parties to review potentially many CRS charges, each of which would be updated annually. We do not think any of the parties would endorse such an elaborate regulatory effort if there were options that would obviate the need for it. We also wonder whether the existing proposal would permit dramatic fluctuations in the CRS over time, a type of financial uncertainty that is a significant concern to parties representing CCAs and prospective CCAs. Moreover, we are not certain precisely what "vintaging" would entail on the basis of the existing record and whether in fact the parties agree on what it would entail.

For these reasons, we state a predisposition toward the concept of vintaging but will defer adopting a way of allocating CRS liabilities until after we have explored the matter in more depth in Phase 2. As a preliminary matter, the approach we ultimately adopt for how to develop a CRS for each generation of CCA should, to the extent possible, balance several criteria. It should balance accuracy, equity among different generations of CCAs, administrative simplicity, and certainty for CCAs and the utilities. We also anticipate that each CCA's CRS liability would terminate at some point. We are also interested in an approach that would permit the utilities to develop the forecasts themselves, to the extent possible rather than relying on DWR. One possible model is to adopt a package of liabilities for each generation of CCA that would be fixed (although the dollar liability would vary with changes in market prices) and could therefore be paid off by a forecast date. We also need to consider specifically what liabilities would be included in each generation of CRS and how to incorporate future procurement obligations in any future CRS. We need to consider whether CRS liabilities would be in all cases paid in a charge per kilowatt-hour or whether a CCA could negotiate a quicker pay off CRS liabilities. There may be other options to explore.

We will direct the ALJ to convene workshops and, if necessary, additional hearings on this topic. Because the parties appear to agree on the underlying principles of how to approach this issue, we encourage them to work together to develop a detailed proposal that meets the several criteria we have identified here and which reflects the parties' various and common interests.

C. Utility Resource Planning

The creation of CCAs and transfer of utility customers to them will change the utilities' load and resource plans. The cut-off date for what is included in the CRS for each "vintage" was a matter of considerable concern to all parties. Prospective CCAs want to limit their liability for power commitments made by the utility on behalf of CCA customers. Utilities on the other hand are concerned about system reliability and financial risks to their bundled customers.

SCE proposes that CCA customers be required to pay for all utility procurement incurred up to the date that service is switched from utility service to the CCA. LGCC opposes this, arguing that Section 366.2(f)(2) permits only the recovery of "unavoidable" electricity purchase contract costs that are "attributable to the customer."

PG&E would have the Commission vintage CCA charges only after all long-term procurement matters have been resolved, including those implicated in Phase 2 of this proceeding, and the procurement docket, R.04-04-003. PG&E is especially concerned that issues relating to switching be resolved so that PG&E can plan for procurement contingencies in its role as provider of last resort.

LA/CV and most parties agree that the utility and its bundled customers should assume full responsibility for any future procurement costs and risks assumed after the CCA is established. LGCC would go further by excluding from the CRS costs from any contracts signed after the passage of AB 117.

LA/CV express concern that SDG&E, and potentially other utilities, may fail to consider changes in their resource plans to reflect future changes in load resulting from CCA operations. LA / CV argues that SDG&E has already failed to reflect CCA load in its recently-signed power contracts (approved in D. 04-06-011) even though it was aware that the City of Chula Vista had created a CCA in mid-2001. It argues that SDG&E appears to be racing to sign contracts in a manner that will force CCAs to subsidize such purchasing decisions.

Discussion. The objective of AB 117 in requiring CCAs to pay a CRS is to protect the utilities and their bundled utility customers from paying for the liabilities incurred on behalf of CCA customers. Our complementary objective is to minimize the CRS (and all utility liabilities that are not required) and promote good resource planning by the utilities.

We agree with the parties that the CRS must change to reflect changes in the utilities' resource portfolios. We take PG&E's concerns seriously with regard to the many elements of long-term planning that are implicated by the CCA program. On the other hand, PG&E seems to argue that implementing various rules will make its forecasting job substantially simpler. However, we are not convinced that implementing a switching rule and finalizing a single long-term resource plan will alone substantially reduce forecasting uncertainty. Utility resource plans will need to balance supply security with enough flexibility to accommodate many market contingencies in addition to those associated with the CCA program, as we have recognized. Because it would ideally recognize and anticipate changing markets and supply sources, resource planning will necessarily be an ongoing, interactive exercise.

We do not agree with LGCC that the CRS should exclude any energy commitments entered into following passage of AB 117. As long as the utilities have made reasonable assumptions about future electricity demand, the CRS must include all stranded costs that occur when customers transfer their accounts to the CCA. Although some cities and counties have formed CCAs or expressed an interest in forming CCAs, the utilities have had little basis on which to forecast reductions in load that would occur as a result of AB 117.

On the other hand, SCE's proposal to include in the (vintaged) CRS all contract costs incurred up to the date customers transfer to the CCA is not consistent with the law. There will surely be circumstances where contracting for more energy, assuming all CCA load, would be "avoidable" and where those commitments would not be "attributable to the customer." We share the parties' concerns that the utilities must recognize CCA load in their resource planning and should not sign contracts that might create new liabilities for CCA customers and utility customers where available information suggests the power might not be needed. We understand the utilities face a difficult balancing act by assuring adequate and reliable power supplies in amounts that reflect forecasts that are changing constantly. However, the utilities are accustomed to using available information to forecast customer demand and should incorporate CCA load losses into their planning efforts, just as they would include any other forecast variable related to expected changes in supply or demand.

We will address these matters in more depth in the utilities' resource planning applications and related dockets. With this in mind, we state our commitment to continue to coordinate CCA program elements with our oversight of utility procurement portfolios and resource planning. This should minimize unneeded power purchases by utilities and therefore the CRS.

D. Unbundling of CRS Components

LGCC proposes the CRS be unbundled in order to permit a comparison of each component of the CRS with market benchmarks. LGCC expresses concern that the model currently cannot be understood by any except modelers at DWR and Navigant. Unbundling would make the model components more transparent. LGCC believes unbundling would obviate the need for frequent true-ups and will promote better decision-making by CCAs.

TURN, ORA and SDG&E support some unbundling on customer bills. SDG&E bills for past power purchases with a Competitive Transfer Charge (CTC) that is separately stated on customer bills and therefore need not be included in the CRS. SCE proposes that the Commission confirm that its current CTC would be imposed on CCA customers. PG&E has a "historic utility charge," which should be identified on customer bills the way SDG&E has unbundled its CTC.

Discussion. We understand LGCC's concern that the CRS model is not transparent to most and that identifying cost components individually may provide CCAs and customers with more of the kind of information they need to make good decisions. On the other hand, we cannot tell from the record exactly what LGCC's proposal entails beyond requiring the utilities to break down the CRS components according to the types of costs they incur. LGCC does not make a convincing case that we should abandon DWR's model for forecasting those components.

In order to address some of LGCC's concerns with regard to the components of the CRS relating to utility costs, we direct the utilities to provide to Energy Division staff and any party so requesting that information calculations of each utility cost component, a description of each related assumption, and an explanation of how each component conforms to this decision. The remaining components would relate to DWR costs. The Energy Division will consider requests for a workshop to discuss the information the utilities and DWR provide. To the extent such information is claimed to be confidential, the utilities and DWR may require parties to sign nondisclosure agreements.

We will also direct the utilities to propose a tariffed offering that unbundles CRS elements on CCA customer bills that are not already unbundled or which they do not plan to unbundle.

E. Credits or Liability for "In-Kind" Power

The CRS is intended to collect liabilities associated with power purchase contracts entered into by DWR and the utilities. These liabilities would become "stranded" if utility customers become CCA customers in the absence of the CRS. Because CCAs would be paying for this power, some suggest they should be entitled to take delivery of the power.

Cal-CLERA and King's River propose that the Commission order the utilities to provide energy to the CCAs in proportion to their CRS liability. SDG&E and SCE argue that CCAs are not entitled to these utility assets and that AB 117 does not suggest this is an option. SCE recommends that if the Commission were to require an assignment of power to the CCA that it should require the CCA to take all power assigned to CCA customers rather than only the power that is priced above market. SCE and DWR believe there may be administrative difficulties transferring power liabilities to CCAs. PG&E argues that it cannot assign a power contract or part of it to another entity.

Discussion: Prospective CCAs would like to receive power from specific DWR contracts, which constitutes a physical allocation. The physical allocation of power from the DWR contracts to CCAs, to the extent it is possible or beneficial, may entail some negotiations and the development of service agreements. We assume that financial liability for the DWR contracts should remain with DWR, and do not believe it is possible for DWR to assign its contracts to CCAs. In any event, we should not pass on an opportunity to minimize the state's liability for overpriced and otherwise stranded assets on that basis. We doubt whether the Legislature in its enactment of AB 117 would endorse a circumstance wherein an entity of local government and its citizens are required to pay for energy supplies they do not receive and which could be provided at little or no cost, assuming this is a possible scenario.

We do not understand the utilities' view that a CCA who takes part of a contract obligation should have to assume the entire contract obligation. If that proposal is intended to present a deterrent to or penalty for the economic use of an asset, we would decline to adopt it. PG&E's argument that it cannot assign only a portion of a contract "since scheduling and dispatch rights under a contract generally reside with only a single party" seems to be circular reasoning: it cannot assign rights to a portion of the contract because it has the only rights to the contract. DWR recognizes PG&E's concerns with regard to the administration of allocating contract portions to CCAs but recommends the Commission explore this approach as a way to mitigate stranded costs.

At this point, the record does not allow us to reach any final conclusions about the extent to which CCAs can or should be able to take power from existing contracts. As a general matter, we believe a CCA should have the opportunity to take delivery of any portion of a DWR or utility contract for which it pays through the CRS. On the other hand, we are not sure what this might entail. Accordingly, we will consider this matter further in subsequent workshops or hearings in Phase II of this proceeding.

F. Open Season

SDG&E proposes that the utilities conduct an open season during which a CCA or prospective CCA would be required to commit to a specific load forecast identifying the load expected to be served by the CCA. The open season would be conducted before the utility buys power for that load and according to the utility's resource planning schedule. The objective would be to mitigate the possibility that both the utility and the CCA would be procuring power for the same group of customers. SDG&E proposes that the CCA assume liability for differences between its load forecast and actual demand (and presumably be credited in cases where the difference results in lower costs as well). The proposal presumes that the utility would act as provider-of-last resort in cases where the CCA did not have access to adequate power. If the Commission were to adopt this proposal in concept, SDG&E would provide more details about its operation in Phase 2.

CCSF, ORA, SCE, and TURN support this idea in concept. TURN suggests the utilities be permitted to impose penalties for a CCA's failure to meet its commitments with regard to the timing and demand forecasts of its operations. LA/CV believes an open season would be duplicative of long-term resource planning efforts. It also raises a concern that the CCA's failure to meet its commitments may be due to the failure of the utility to perform services for which the CCA pays.

Discussion. We agree with the parties who advocate in favor of an open season as a way to promote sound resource planning by the utilities and the CCAs, and also facilitate operations. SDG&E's proposal for CCAs to assume the risks associated with forecasting errors is reasonable and similar to the balancing fees we have approved for gas transportation tariffs. Utility tariffs should include fees that bear a reasonable relationship to the costs the utilities will incur as a result of the suspension of the CCA's initial operations or to schedule power on behalf of CCAs. We expect utility tariffs to provide for the forgiveness of such penalties for CCA non-performance if the reason for that non-performance relates to a failure of the utility to meet its commitments to the CCA in any way, for example, with regard to connections, transfer of customer information, mailing of customer notices or any other operational activity.

Although we state our support for an open season here, we agree with the parties who suggest this is a matter that requires further exploration in Phase II of this proceeding. For that reason, we include the matter in Phase II and expect to develop and adopt the details of an open season in a subsequent order. However, we do not intend to delay the initiation of service by CCAs while we are considering this matter. In the interim, the utilities must accommodate CCAs that wish to begin delivering power.

The issue of whether and how the utilities have obligations to CCA customers as "providers of last resort" is a matter we consider in R.04-04-003. We direct the utilities to submit draft tariffs for such services as back-up power and balancing services and will address these matters further in Phase II of this proceeding.

G. Responsibility for CRS Liabilities

LA/CV and CalCLERA raise the issue as to whether the CCA or its customers should be responsible for the CRS. Whether the CCA or its customer receives the bill and pays it, the customer will ultimately assume the cost. The issue is whether the CCA or the utility should determine cost allocation and the arrangements for payment if the CCA assumes liability for the payments. DWR, the utilities and bundled customers would be indifferent on this issue as long as the utility and DWR received the CRS revenues. SCE, however, believes these utility liabilities should be billed directly to customers so the Commission is certain that the way they are allocated is just and reasonable. DWR expresses concern that the assumption of this liability by a CCA may have some implications for its bond and power charge obligations.

Discussion. AB 117 requires the CRS charge to be imposed directly on the customer. Section 366(d)(e) and (f) refer to the obligations of "retail end-use customers" assuming the costs of the components of the CRS in "commission-approved rates." Because of DWR's expressed concern, we adopt the utilities' proposals for billing customers directly for the CRS.

H. Collection of Amounts Relating to CRS Exemption for Baseline Customers

Water Code Section 80110 provides that so long as DWR is recovering its energy procurement costs, the total rate for residential customers with usage below 130% of baseline amounts must remain at the same level as those rates in effect on February 1, 2001. This subsidy is referred to as the "Baseline Exemption." Cost liabilities adopted since that time have been allocated to other customers. The resulting shortfall has been allocated in equal portions to residential, commercial and industrial customers. This subsidy program created by AB1X does not apply to CCAs, although they could voluntarily implement it by structuring their energy cost recovery so that baseline customers do not pay the CRS. Bundled service customers, however, should not have to subsidize residential CCA customers. All parties agree this subsidy should be assumed by the CCA, not bundled customers.

Each utility proposes a different way to implement the subsidy for baseline customers. PG&E is concerned that this subsidy to low-usage customers would promote "cherry picking" of customers by CCAs. To ameliorate this possibility, PG&E would calculate each CCA's CRS liability by estimating the composition of the CCA's customer usage. SCE would allocate the costs of the residential baseline subsidy in a rate component that would apply equally to bundled service customer, direct access customers and CCA customers. SDG&E's proposal is similar to SCE's except that SDG&E would bill CCA customers for the CRS as a nonbypassable surcharge, and unbundle the same amount on its own bundled customer bills in order that no customer may escape liability for related costs.

LGCC and CCSF support SCE's proposal. CCSF and SCE oppose PG&E's proposal to impose the CRS according to the composition of a CCA's customer base. CCSF believes this disparate treatment of CCAs on the basis of customer class characteristics would violate the prohibition on cost-shifting. SCE objects to SDG&E's proposal on the basis that its objective to collect CRS revenues is more readily implemented without the need for another nonbypassable surcharge. SDG&E comments that PG&E's proposal fails to recognize that the AB 1X requirement applies to CCAs as well as utilities and may violate AB1X for that reason.

Discussion. As a preliminary matter, we make no determinations about whether and how a CCA should apply a baseline rate. Because CCAs would be governmental agencies that are accountable to the public, they can be entrusted to design cost allocation according to the needs of their local communities and the types of liabilities they incur with respect to allocating the revenue shortfall. SCE's proposal has the benefit of administrative simplicity and avoids cost-shifting. SDG&E's proposal raises the issue of whether it is wise to add another line item to customer bills, especially for a cost component that is so small and may, as SCE suggests, be reduced further in the future. Although the parties complied with the ALJ's directive to consider the baseline issue, we believe the scope of this proceeding is not broad enough to resolve a rate design issue that goes beyond costs and revenues related to the CCA program. For that reason, we do not resolve the baseline issue here. Instead, we herein direct all three utilities to propose ways to allocate the costs of the subsidy in ratemaking proceedings such as general rate cases, rate design windows or a baseline application.

I. Exclusion for Norton Air Force Base

IVDA seeks an exemption for Norton AFB from the DWR cost component of the CRS in order to promote economic development at the air force base. It justifies its request for an exception on the basis that SCE did not include Norton's load in the demand forecast DWR relied upon when it purchased power that is subject to CRS treatment. IVDA argues its proposal is consistent with the "fair share" principle adopted in orders addressing similar issues for municipal departing load (D.03-07-028) and customer generation departing load (D.03-04-030). IVDA argues that granting an exclusion for Norton AFB is consistent with the prohibition against cost-shifting because DWR did not incur any power costs on behalf of Norton. IVDA believes the prohibition against cost-shifting should be applied consistently to permit a CCA or its customers to receive the benefit of that prohibition as well as assume the liabilities. LGCC supports IVDA's proposal for reasons similar to those put forth by IVDA.

The utilities oppose this exclusion on the basis that it requires other CCA customers or utility customers to make up the difference in contravention of AB 117. PG&E argues the exclusion would be inconsistent with Commission policy on exclusion from DWR bond costs and that DWR forecast no CCA load prior to entering into subject contracts. SCE admonishes IVDA for seeking to capitalize on base closures and argues that IVDA is seeking an exclusion for more acreage than that which comprised Norton AFB.

Discussion. SCE's forecasts to DWR, and upon which DWR relied in signing purchased power contracts, assumed that Norton AFB would close and therefore demand no power during the periods in question. Since that time, IVDA plans to build out at the site.

Because DWR did not purchase any power on behalf of Norton AFB, ratepayers would not be harmed if IVDA is excluded from the DWR component of the CRS. IVDA's interpretation of AB 117 that the prohibition on cost-shifting should work in both directions is reasonable. Although we do not assume the statute requires this reciprocal treatment, we believe we can lawfully permit an exclusion or exception to the CRS requirements on that basis.

The acreage which would apply in this case is not relevant. The exclusion would apply to the load removed from the SCE forecast. For all the forgoing reasons, we direct SCE to exclude IVDA from the DWR component of the CCA CRS for amounts equal to the reduction in demand included in SCE's forecast to DWR. In its brief, SCE states this amount is 523 MWh or 120 kW capacity. IVDA should be permitted to confirm this amount or challenge its accuracy in Phase II of this proceeding.

We clarify here that IVDA's adopted exemption from the CRS applies only in the event IVDA establishes a CCA pursuant to the requirements of AB 117 and proceeds to purchase power for residents and businesses located on the Norton Air Force Base. If IVDA seeks an exemption from the CRS generally, it must seek that exemption in R02-01-011.

J. CRS True-Up

The utilities, DWR, and CCSF propose that the CRS be "trued-up" annually so that undercollections or overcollections are recognized in the subsequent year's CRS. These credits or debits, with interest, would be applied equally to all CRS vintages. PG&E illustrates the risks of forecasting a CRS by observing that DWR estimates for PG&E for 2006 ranged from about $21/MWh to about $51/MWh, depending on market conditions.

CalCLERA and Local Power argue for a forecast CRS for which the utility would be liable. Local Power interprets AB 117 to require the Commission to set a CRS on the basis of a forecast and retain the CRS from year to year. Related to this, several parties proposed a cap on the CRS or a mechanism that would effectively cap the CRS. CCAs and prospective CCAs argue that the cap will provide much-needed certainty. Local Power appears to advocate that the utilities' shareholders should assume the risk associated with a cap. The utilities, ORA and TURN oppose a cap, arguing that a cost cap could cause unlawful cost-shifting or expose shareholders to risks AB 117 does not intend.

Discussion. AB 117 does not refer explicitly to a true-up of the difference between a forecasted CRS amount and actual CRS liabilities, which can only be precisely identified retrospectively. Local Power argues that the statute prohibits a true-up. It refers to Section 366.2(c)(7), which states that "After certification of receipt (from the CCA) of the implementation plan and any additional information requested (of the CCA), the commission shall then provide the community choice aggregator with its findings regarding any cost recovery that must be paid by customers of the community choice aggregator to prevent a shifting of costs…" This language might suggest that the Commission would inform the CCA of a specific total dollar amount for energy contract liabilities.

However, other elements of the statute are clear that utility bundled customers must not have to pay for energy contract liabilities that were incurred on behalf of customers that are ultimately served by the CCA. This is the provision referred to as the “prohibition against cost-shifting.” For example, Section 366.2 (c)(5) refers to developing a cost recovery mechanism that would “prevent shifting of costs.” Section 366.1(d)(1) states the Legislature’s intent “to prevent any shifting of recoverable costs between customers.” Section 366.2(f)(2) directs the Commission to set a CRS based on “costs attributable to the customer.” Here, the statute states a broad intent to prevent cost-shifting and subsequently refers to that intent clearly and explicitly in sections implementing the cost in question, namely, the CRS. Although the statute never refers to a true-up by any name, it assumes a true-up by implication: because a forecast of the CRS will never exactly match actual costs, setting the CRS according to a forecast that could not be trued-up would permit shifting costs between CCA customers and utility bundled customers. In contrast, the section that might imply a fixed and specific dollar liability is referred to obliquely in a section that describes a transaction between the Commission and the CCA, namely the Commission’s duty to “inform” the CCA of its cost liability following review of the CCA’s implementation plans and other information. In a case, such as here, where the statute might appear to present a conflict, we must look to the statute as a whole and follow that requirement that is articulated in the statements of Legislative intent and supported by explicit language in subsequent sections of the statute.

We find that AB 117 requires that CCA customers pay the actual rather than forecasted costs that are components of the CRS. We agree with the utilities and consumer groups that the CRS should be trued up annually. An annual true-up is reasonable because it will mitigate the possibility of large swings in CRS levels that more accurately match costs with cost causation than true-ups over longer periods. Similarly, we do not adopt a CRS cap for CCAs. Whether or not the idea is sound from a policy perspective, we believe AB 117 prohibits a rate recovery mechanism that might result in cost-shifting between customers and we would not put the utilities at risk for investments that are stranded for reasons they could not control or foresee.

The utilities should enter CRS costs and revenues into relevant balancing accounts, as they propose, which will be reconciled annually in proceedings addressing the CRS for direct access customers. At this time, the appropriate docket is R.02-01-011.

K. CRS Implementation

Having considered the general methodology and cost allocation treatment for the CRS, we must decide how to implement it. The utilities do not assume the Commission will adopt a number in this phase of the proceeding, preferring to address the issue again and in more detail in subsequent hearings. DWR presented illustrative CRS values but explicitly does not endorse any at this time. DWR offers to work with the utilities to develop final values after the Commission resolves outstanding issues about the CRS methodology and its application. Only one party proposed a specific CRS number for the Commission's consideration. CCSF proposed the Commission adopt a 1.5 cent CRS for a two-year period, which it estimated using DWR's methodology and forecast gas prices. CCSF originally referred to this number as a "cap" but clarifies its view that it should be subject to subsequent modification to reflect market conditions and power commitments, consistent with the utility proposals. CCSF argues that CCAs need some early indication of the level of the CRS for planning purposes.

PG&E argues that CCSF's CRS is substantially below those DWR presented using various market scenarios and was not proposed for SCE or

SDG&E. PG&E argues that this phase of the proceeding was not designed to develop an actual number for the CRS.

Discussion. We clarify first that one objective in Phase 1 of this proceeding is to quantify the costs of service and the CCA CRS. This objective should be clear on the basis of the parties' discussion at the prehearing conference with regard to the need to bifurcate the proceeding. Many stated a concern that their litigation of operational issues in this proceeding would be superfluous if the Commission were to set costs at levels that CCAs and prospective CCAs believed were too high to justify developing energy procurement programs. The scoping memo agreed to bifurcate the proceeding on the basis of that discussion. An ALJ ruling dated January 29, 2004 also stated the Commission's intent to develop a CRS in Phase 1.

The utilities' current proposal to delay adoption of a specific CRS amount until after Phase 2 would undermine the Commission's commitment to provide CCAs and prospective CCAs with some early indication of the costs they can expect to incur if they choose to procure energy. Agreeing to wait until after the resolution of Phase 2 issues could delay implementation of the CCA program until mid- or late-2005, almost three years after the enactment of AB 117.

Nor do we agree with the utilities that the record does not provide adequate information to adopt an interim CRS. In fact, we are not sure what the utilities would have the Commission explore in Phase 2 hearings on this issue since the parties agree to the DWR model and its components and this decision resolves related issues.

Adopting an initial CRS amount at this point would require a leap of faith, but one that is reasonable considering the results of the DWR's modeling. DWR presented a sensitivity analysis that included illustrative ranges of CRS amount that vary depending on assumptions about market conditions. DWR explains that components of the CRS related to the DWR bonds and historic utility stranded costs are fairly stable and do not depend much on market conditions. The more variable components of the model are the utility CTC and DWR power charge, which may vary considerably depending on market conditions such as gas prices, load growth, capacity additions, and reserve margins.

Importantly, DWR's analysis shows that the CRS may vary markedly from period to period, and is unlikely to be predictable or stable because of its sensitivity to changing market conditions. This understanding that minor changes in market conditions may have a pronounced effect on the CRS is disappointing from the standpoint of our effort to accommodate the CCA's need for some degree of certainty with regard to their CRS liabilities. On the other hand, it removes one of the arguments for delay, that is, that additional work in this area will provide a more accurate CRS. Additional precision in the modeling may be technically appealing but market conditions that are largely unpredictable and out of our control appear likely to have a more pronounced effect of the level of the CRS level than additional precision in the modeling.

For all the foregoing reasons, we find the record in this proceeding is adequate to adopt an initial CRS using the analysis presented by DWR and CCSF. To avoid further delay, we proceed to fashion an interim CRS that is based on available information and analysis and which may be modified immediately if final CRS calculations are substantially higher or lower than the one we adopt today. This charge, like all CCA CRS amounts, shall be subject to true-up based on actual DWR and utility liabilities.

DWR presented the following range of CRS levels in cents per kilowatt-hour for each of the three electric utilities for 2005 and 2006:

	2005	2006
PG&E		
Range	1.60-2.99	1.00-3.99
Base case	2.28	2.59
SCE		
Range	1.75-3.40	.650-3.85
Base case	2.51	2.35
SDG&E		
Range	2.24-3.34	1.03-3.71
Base case	2.60	2.18

CCSF's estimate of \$.015/kWh is on the low end of DWR's range because it applied higher gas prices using more recent market information which reduces CRS liabilities.

While we acknowledge that these estimates are not perfect, they nevertheless permit us to adopt a CRS today that may be trued up later, on the basis of the costing principles we adopt in this order. We will therefore establish a CRS today that may be modified either in 18 months or sooner in the event the utilities' final CRS estimates, using more recent forecasts, are at least 30% higher or lower than the adopted CRS. We set the first CRS at \$.020/kWh which lies well within the range of CRS estimates presented by DWR. For SDG&E and SCE, DWR's forecasts for 2006 are considerably lower than those for 2005 and gas prices have fallen substantially since DWR conducted the forecasts presented in this proceeding. For these reasons, we believe \$.20 is a reasonable estimate of outstanding liabilities for the next 18 months and may ultimately turn out to be high. Our objective is to avoid a circumstance where a CCA relies on an artificially low CRS only to later have to make up the difference with a substantially higher charge. We balance this objective with our wish to avoid setting the CRS too high and thereby create a barrier to CCA development. We believe $0.020/kWh achieves the appropriate balance. This amount would be in addition to nonbypassable surcharges already on customer bills for bond liabilities or historic utility costs. In subsequent periods, the CRS would differ for each utility because, as DWR explains, utility power liabilities differ.

Consistent with our previously-stated concerns that the CCA program move ahead in spite of slow progress to implement program elements, we direct the utilities to file tariffs within 60 days of the effective date of this order that would set the initial CRS at $.020/kWh, effective January 1, 2005. This amount will be trued-up and recalibrated in 18 months or when the utilities' forecast CRS is more than 30% higher or lower than $.020/kWh. Thereafter, the CRS shall be trued-up every year and possibly vintaged in related DWR revenue requirement proceedings, the details of which will be examined in Phase 2.

V. Informational Needs of CCAs

CCAs must have certain types of information in order to plan their procurement strategies, assess the viability of offering energy services, and to contact customers. Section 366.2(c)(9) anticipates the needs of CCAs for certain types of customer data and information:

> "All electrical corporations shall 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."

D.03-07-034 has already directed the utilities to provide CCAs with certain information at no charge to the CCA. R.03-10-003 and the ALJ's November 26, 2004 ruling found that remaining issues regarding the provision of information to CCAs should be resolved in Phase 1 of this proceeding. Accordingly, the ALJ directed the utilities to meet with interested parties on these issues and to file a report on the results of the meetings. The utilities held such meetings and on January 30, 2004, the utilities filed a Joint Utility Report on Community Choice Aggregation Information Issues which formed the basis for the debate on related issues.

In this area, the main issues addressed in this proceeding concern the kind of information the CCAs should be entitled to receive and the confidentiality of customer information.

The information the CCAs may need from the utilities may be confidential, for example, (1) basic load and usage data required to estimate energy procurement needs and (2) customer information needed to contact customers and provide services, including name, address, and meter information. A major dispute is over whether the type and nature of information should differ before and after the CCA initiates service and the customer is officially transferred to the CCA.

The utilities raise general concerns that they not be required to provide confidential information to CCAs except with strict protections for utility customers. SDG&E argues that CCAs must have the written consent of the customer, prior to the customer transferring to the CCA, in order to receive such information, which is current practice for utility release of customer information. Prior to customer cut-over, the utilities agree to provide information on customer load and usage if it is aggregated in order to mitigate confidentiality concerns.

SDG&E argues that CCAs would not need more since, as cities and counties, they would have information about local customers. PG&E proposes to aggregate customer information until the customer is transferred to the CCA and then release all customer information to the CCA. It would continue to offer basic information required by D.03-07-034 at no charge to the CCA and provide a standardized list of information to the CCA at cost. It asks the Commission to approve tariff provisions that would have the CCAs indemnify the utilities from liabilities they might occur from the release of customer information.

ORA generally agrees with the utilities' proposals and suggests that customer notification letters be drafted by the CCAs but mailed by utilities to accommodate confidentiality concerns that arise before cut-over to the CCA. ORA shares the utilities' concerns that load data remain aggregated and argues that CCAs do not need more in order to forecast load. In response to CCA concerns that they cannot market services without specific customer load data, ORA agrees with SDG&E and PG&E that cities and counties have access to tax rolls that they may use to contact individual customers.

LGCC objects to the many rules the utilities would implement to limit the amount of information LGCC argues is required for CCAs to market and provide energy services. LGCC, for example, objects to the utilities' proposed requirement that a CCA provide projected load forecasts to the utilities, and assume the risk that the forecast is accurate, while simultaneously proposing to deny the CCAs access to load information that it could not otherwise obtain. It argues that aggregated load data would not provide enough information for CCAs to conduct meaningful marketing and load forecasting. LGCC believes customer confidentiality would not be compromised if the individual load data was masked so that it did not identify the customers. ElectricAmerica goes into some detail about the kinds of information CCAs may need, most of which would be included in existing utility data bases.

Local Power believes the statute is clear with regard to its requirement that utilities provide all relevant information to CCAs that are "investigating, pursuing or implementing" CCA programs and suggests that confidentiality concerns may be addressed by imposing limits on the CCA's use of the information it gets.

LA/CV contends that customers have implicitly agreed to the release of their information when their duly elected public representatives form the CCA. LA/CV believes the CCA is a consortium of customers, as distinguished from the direct access program, where customers must affirmatively choose to change their service provider rather than opt-out of service offered by the CCA. LA/CV and Local Power also observe that AB 117 requires the CCA to notify utility customers of the CCA's plan to offer service, a requirement the CCA cannot satisfy without customer billing information.

The utilities assert that they should only be required to provide information that is directly relevant to the CCA's energy operations. LGCC suggest that the information requirements adopted in D.03-07-034 on behalf of CCAs is the minimum necessary for prospective CCAs but suggests the utilities have not been cooperative with prospective CCAs in working on their other information needs.

Discussion. AB 117 is clear in its intent to require the utilities to provide CCAs all customer and usage data that is relevant to CCA operations even before the CCA begins offering service. In addressing the informational needs of CCAs, Section 366. 2(c) (9) provides that the utilities shall "cooperate" with CCAs that "investigate or pursue" CCA programs. Because a CCA is most likely to "investigate or pursue" CCA programs before it begins offering service, we read the plain language of the statute to mean relevant information must be provided on demand, without distinguishing between a customer who is still with the utility or a customer of the CCA or between the time a CCA is created and the time it provides service. By law, CCAs are entitled to receive certain types of information as long as they are investigating, pursuing or implementing a CCA program.

Section 366.2(c)(13) (A) supports this finding in its requirement that CCAs provide opt-out notifications to prospective customers prior to cut-over. Although Section 366(2) (13)(B) gives the CCAs the *option* to request utility assistance with the notifications, each CCA must assume ultimate responsibility for the notices. The CCA cannot satisfy this responsibility without access to customer names and addresses. Thus, if the Legislature had intended for customer information to remain with the utility, it would have not required the CCA to issue the opt-out notices.

SDG&E argues that D.01-07-032 and D.90-12-121 should apply in this case. Those orders prohibit a utility from disclosing customer information even to a district attorney without either the customer's consent or the order of a judge. The facts in that case, however, are distinguishable from those here, primarily because the statute itself directs the provision of customer information to a CCA. Moreover, unlike a district attorney investigating criminal activity. The statute permits the CCA to receive such information. Unlike the unwilling subject of a criminal investigation, the customers for whom the CCA seeks information have implicitly agreed to permit the CCA to aggregate their energy requirements and offer service.

We believe AB 117 assumes, as we do, that CCAs can be entrusted with confidential customer information. Unlike energy service providers offering direct access, CCAs are government agencies. As long as some basic protections are in place, the risks of providing confidential information to these entities is outweighed by the dictates of the statute and the potential benefits CCA customers would realize only if CCAs have the information they need to make fully informed decisions regarding energy procurement, service requirements and resource planning decisions. To help assure that cities and counties do not seek information casually, we will require as a condition of receiving utility information that the mayor or chief county administrator sign a letter attesting to the city or county's intent to "investigate" or "pursue" status as a CCA.

In addition to its requirement that utilities provide information to CCAs before and after they initiate operations, AB 117 specifies the types of information the utilities must provide to CCAs. Section 366. 2(c)(9) refers to "appropriate billing and electrical load data, including, but not limited to, data detailing electricity needs and patterns of usage." The statute specifically refers to "billing" data as distinct from "electrical load data." We are not aware how aggregated or masked billing data could satisfy the statutory requirement. Again, the plain language of the law means that the CCA is entitled to any and all billing data that is reasonably useful to the CCA. It also refers to information "detailing" electricity needs and patterns of usage. Use of such specific terms reflect the Legislature's intent for CCAs to have information that is neither masked nor aggregated, to the extent such information is required by CCAs that would reasonably "investigate, pursue or implement" a CCA program.

This approach is consistent with our understanding that CCAs may need specific usage information in order to market their services and tailor those services to customer needs. We are not convinced by utility testimony that city and county tax rolls will provide the kind of information CCAs need to accomplish those ends.

We direct the utilities to provide all relevant usage information, load data and customer information to CCAs. The CCA shall sign nondisclosure agreements for any confidential information that is not masked or aggregated. We will also require that all notices relevant to CCA programs inform customers that the utility may share customer information with the CCA and that the CCA may not use the utility's information for any purpose other than to facilitate provision of energy services.

We agree with PG&E and SDG&E that the utilities should be permitted to include language in their tariffs that CCAs indemnify the utility from liability associated with release of customer information, as long as the utility provided the information responsibly and according to Commission rules, orders and approved tariffs. Utilities should inform customers who complain about the release of customer information that California state law requires the release of that information to CCAs.

We also agree with PG&E that confidential information about a utility's market, market strategies, procurement efforts or contracts (as addressed in R.04-04-003) is probably not among the types of "appropriate" information to which CCAs are entitled. If a CCA seeks such information and the utility objects to its provision to the CCA, we will consider this disclosure on a case-by-case basis in this proceeding. Hopefully, as PG&E suggests, we will ultimately have a list of the types of information that are automatically available to CCAs and the types of information that would not be available to CCAs. This list can more readily be developed after the utilities gain experience with the CCA program.

Finally, we state our intent to enforce the law with respect to its requirement that the utilities "cooperate" with CCAs in the provision of all relevant information, a term which we interpret broadly. The utilities may not determine what information is "relevant" to CCA operations as long as the utility is reimbursed for the reasonable costs of providing the information. While we welcome the utilities' tariff proposals for the secure and cost-effective sharing of information, we will not tolerate utility actions or delays that may affect the provision of information to CCAs or CCA services to customers.

It may, however, be reasonable for utilities to provide aggregate data by customer type or geographic area at the beginning of the process, when a potential CCA is investigating whether to pursue becoming a CCA, whereas more detailed customer and billing information is warranted when the CCA is developing its implementation plan.

VI. Other Issues and Terms of Service

A. CCA Program Phase-In

LGCC, CCSF and other prospective CCAs suggest that a CCA should be able to phase in their programs, that is, offer service to some customers or customer classes before others. PG&E supports this concept to a limited extent as long as it does not lead to cost-shifting. SCE and SDG&E propose that the CCAs cut-over all customers concurrently to avoid the administrative costs of phasing and to avoid "cherry picking" of most valuable customers and thereby undermine those portions of AB 117 that refer to universal service and equitable treatment of customers. PG&E proposes to permit phasing, as long as the cut-over is accomplished within six months, in order to ease the administrative burdens of the transfer.

Discussion. AB 117 does not prohibit a phase-in of the CCA's program or customer cut-overs. In advocating for a prohibition on a phase-in, SCE relies on Section 366.2(c)(4)(A)(B) which directs CCAs to develop an implementation plan that "shall provide for…universal service" and "equitable treatment of all customers." SCE appears to argue that these terms require that all customers be treated equally in all respects. We do not agree that this is what the statute requires. The terms are not defined or discussed in any other portion of the statute and, alone, are so broad that they are subject to considerable interpretation. Indeed, "universal service" and "equitable treatment" are concepts that have been subjects of debate and policy decisions in numerous Commission dockets over the years. Without more guidance from the statute, we cannot assume these terms preclude a phase-in.

However, we need not delve further into statutory interpretation on this issue. Rather, we leave the matter to the CCAs. We note that a pilot program may facilitate a CCA's program implementation in some respects by, for example, allowing it to develop its administrative structure incrementally or to purchase power supplies in specified quantities. Thus, the barrier to a pilot program or phase-in would not be the law but the possible additional costs of administering the cut-over of customers from the utilities to the CCAs that might occur, for example, as a result of differing load profiles and shifting procurement requirements, as ORA suggests. PG&E proposes a limited phase-in that might actually mitigate costs. We direct the utilities to propose tariffs that offer a phase-in at rates and charges that would recover such costs, consistent with other portions of this order addressing implementation and transaction costs. Their tariffs should permit the utilities to negotiate with the CCA to phase-in the CCA's program in ways that promote cost-savings, as PG&E suggests, and the associated cost savings should be reflected in the negotiated outcomes.

B. CCA Requirements to Offer Service

LA/CV and other CCAs believe CCAs should be permitted to offer service to a portion of local customers. The utilities argue that AB 117 requires CCAs to offer service to all customers.

Section 366.2(b) requires the CCA to "offer the opportunity to purchase electricity to all *residential* customers within its jurisdiction." (Emphasis added.) A general rule of statutory construction provides that where the language of a statute is specific, all other things not specified are excluded from the application of the rule unless other terms of the statute clarify or conflict with the rule. Here, the statute requires service offering to all residential customers and does not mention a similar requirement for commercial or industrial customers. The reference to residential customers does not conflict with any other provision of the statute. We therefore find that AB 117 does not prohibit the CCA from offering service to a portion of customers in its territory, with the exception that it must offer service to all residential customers. As long as the utilities' tariffs reflect the costs of serving the CCA and the requirements of the utilities' tasks are reasonable and otherwise lawful, this Commission is indifferent to whether a CCA offers service to a portion of the community or all of it.

C. CCA-Specific Load Profiles

Some parties propose that the Commission use load profiles specific to individual CCAs in computing the CRS and for scheduling and settlements with the California ISO. CCSF observes that CCAs would have differing load profiles according to regional climate and economy. LA/CV proposes a relatively easy way to develop load profiles that may be useful for various purposes.

The utilities oppose this on the basis that the ISO still uses system average load profiles. If the Commission were to permit some but not all CCAs use specific load profiles, the utilities would realize a revenue shortfall which would have to be passed along to other ratepayers in contravention of the AB 117 ban on cost-shifting. The utilities also raise concerns that they do not have the data bases for creating CCA-specific load profiles and creating them could be expensive.

Discussion. We agree with the utilities that adopting CCA-specific load profiles would be costly and likely lead to cost-shifting. Even if we were to apply CCA-specific load profiles to all CCAs, cost shifting could occur if the bulk of CCAs had favorable load profiles compared to the average of the utilities' systems. While load profiling may make sense conceptually, the effects of its implementation under the current circumstances are unknown and potentially harmful to utility bundled customers. We may reconsider this proposal if the Commission or the FERC eventually unbundle utility systems by region.

Load profiles may be useful to CCAs for other purposes. The utilities believe they may be difficult and costly to develop, although SDG&E addressed a simplified method for developing a load profile that would adjust the system average according to local usage and climate. The utilities' tariffs may offer at cost the development of CCA-specific load profiles or a modified approach based on the system average.

D. Boundary Metering

Local Power suggested that the Commission order the utilities to install an additional CCA meter at every point at which a meter installed by the utility currently exists. SCE maintains concerns that this proposal is expensive and impractical, although it suggests considering the matter one case at a time. PG&E

and SDG&E would also support boundary metering if it were offered on a time and materials basis.

Discussion. Section 366.2(c)(18) provides that "at the request and expense of any community choice aggregator, electrical corporations shall install, maintain and calibrate metering devices at mutually agreeable locations within or adjacent to the community choice aggregator's political boundaries." Again, we read the plain language of this section and, as the utilities suggest, require that they include an option in their tariffs for boundary metering that would be provided at the cost of time and materials.

VII. Comments on Proposed Decision

The proposed decision of ALJ Malcolm in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Commission's Rules of Practice and Procedure. Comments were filed on November 18, 2004 and reply comments were filed on November 23, 2004. The final order adopted by the Commission contains several clarifications to the ALJ's proposed decision and a number of substantive changes with regard to the allocation of program costs and the development of more detailed program elements in Phase II of the proceeding.

VIII. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Kim Malcolm is the assigned ALJ in this proceeding.

Findings of Fact

1. Allocating implementation costs to ratepayers that are related to the development of the CCA program's infrastructure would be fair, relatively simple to administer and avoid the barriers to entry that might occur if a handful of individual CCAs were required to assume those costs.

2. Transaction costs and implementation costs that are attributable to individual CCAs should be charged to those CCAs in tariffs according to the costs of time and materials.

3. The utilities' incremental costing methodologies for CCA transaction costs are reasonable to the extent the utilities do not recover transaction costs twice.

4. Utilities are currently recovering the costs of certain transaction services to CCAs. Permitting the utilities to charge CCAs for those services prior to a general rate case would permit the utilities to recover related costs twice, to the extent the utilities do not incur incremental costs for those services.

5. Tracking revenues from CCA transaction services in an account for "other revenues" would not eliminate the prospect of double recovery because such an account does not provide for refunds for past paid costs; such accounts are considered in general rate cases for forecasted costs and revenues.

6. Approving balancing accounts for implementation costs is reasonable prior to a general rate case to assure the utilities recover reasonable implementation costs.

7. Approving permanent balancing account treatment for implementation and transaction costs would undermine utility incentives for cost containment and is contrary to the Commission's regulatory treatment of customer and operational costs generally. Forward-looking charges will provide certainty for CCAs, provide the utilities a reasonable opportunity to recover their costs, and permit the utilities to take advantage of cost savings and associated opportunities for making a reasonable return on serving CCA customers.

8. The utilities did not propose final charges for CCA services in this phase of the proceeding.

9. Delaying the effectiveness of CCA tariffs until after the close of Phase 2 in this proceeding would unreasonably delay the implementation of the CCA program.

10. Direct access tariffs provide a reasonable proxy for interim CCA tariffs until the Commission has approved final CCA tariffs.

11. The utilities are likely to incur incremental billing costs when they serve CCAs.

12. If CCA fees for processing utility bills are not unbundled, CCAs may be liable for costs related to utility customer services, rather than those incurred for CCA customers.

13. The utilities did not demonstrate that CCA customers will make significantly more calls to the utility than they made as utility bundled customers. The extent to which the utilities must respond to additional calls would be established by directing CCA customers to a separate "800" number for questions about CCA services.

14. Developing the infrastructure for opt-out procedures is an implementation cost attributable to the CCA program generally. The costs of issuing opt-out notices and processing related customer requests is a cost that is attributable to individual CCAs.

15. Re-entry fees are those that reflect the administrative cost of transferring a CCA customer back to the utility as a bundled service customer.

16. The utilities' "Detailed Processes" outlines provide information about how they propose to implement various operations and services for CCAs. These outlines form a reasonable foundation for resolving Phase 1 issues except as provided herein.

17. The Commission has adopted a CRS for certain types of customers in other proceedings.

18. DWR's methodology for developing the CRS reasonably reflects the energy liabilities that should be charged to CCAs, and would appropriately exclude avoidable costs, reflect DWR and utility bond or contract refunds or credits, and apply to new as well as existing customers. No party opposes DWR's methodology for estimating related costs.

19. "Vintaging" as defined by the parties would track the costs that are attributable to an individual CCA's customers depending on the timing of the CCA initiating operations, and reflects the changing liabilities of the utilities and DWR. As envisioned, it may also create substantial regulatory burdens for the parties and the Commission.

20. AB 117 provides that the CRS should include all costs that the utilities reasonably incurred on behalf of ratepayers, which may include costs incurred after the passage of AB 117 but should not include any costs that were "avoidable" or those that are not attributable to the CCA's customers.

21. Unbundling the components of the CRS may provide customers and CCAs with valuable information about the costs of their services.

22. Permitting CCAs to take delivery of power related to CRS liabilities may reduce California consumers' energy bills and promote the interests of the state and its economy. Whether and how power from some utility or DWR energy purchase contracts may be allocated to CCAs is unclear on the basis of the existing record.

23. An "open season," as SDG&E describes it, would help the utilities and CCAs plan for CCA operations in a way that may permit more efficient and effective resource planning.

24. The demand forecasts relied upon by DWR for purchasing power during the energy crisis assumed the installation of distributed generation in California.

25. The exemption from the CRS for baseline usage required by Water Code Section 80110 creates a revenue shortfall that must be recovered from the CCAs or their customers.

26. SCE's proposal to allocate the revenue shortfall from the baseline subsidy to all customers' distribution rates is administratively simple and avoids the customer confusion of an additional nonbypassable surcharge. However, this issue is more appropriately resolved in a ratemaking proceeding such as a general rate case or rate design window.

27. SCE's demand forecasts provided to DWR, and upon which DWR relied in purchasing long-term power, assumed load reductions at Norton Air Force Base in anticipation of the base's closing.

28. The utilities would overcollect or undercollect CCA CRS costs if they were not permitted to true-up in some fashion the difference between the forecasted CCA CRS rate and the actual CCA CRS liabilities, which can only be precisely specified after the fact. Similarly, a cost cap may permit a circumstance whereby the utilities might not be able to recover all CCA CRS costs, as mandated by AB 117.

29. Requiring utility bundled customers to assume liability for the CCA CRS forecast being equal to or more than actual CCA CRS liabilities would represent cost-shifting between utility bundled customers and CCA customers.

30. The Commission has always intended to set cost recovery for CCA services and the CCA CRS in Phase 1 of this proceeding.

31. Delaying the implementation of CCA costs until after the resolution of Phase 2 of this proceeding could delay implementation of the CCA program until almost three years after passage of AB 117.

32. The record in this proceeding does not permit the Commission to approve final rates and cost recovery amounts for CCA services that would be the subject of tariffs.

33. The utilities' tariffs that govern services to direct access customers address services and operations that are substantially similar to those needed by CCAs. They are reasonable proxies for the costs the utilities would incur in serving CCAs while the Commission reviews proposals for final CCA rates and tariffs.

34. DWR's model suggests that minor changes in market conditions could cause substantial variations in the CRS. For that reason, developing more precise specifications for the DWR model may not necessarily significantly improve the reliability of the CRS.

35. The record in this proceeding provides enough information about likely CCA CRS liabilities to set an interim CCA CRS in the amount of $.020/kWh, subject to true-up.

36. Permanent balancing accounts may undermine incentives for economizing.

37. Utility forecasts of the costs of CCA program implementation and transactions in general rate cases would promote certainty and cost management.

38. CCAs would "investigate or pursue" CCA programs prior to offering service and a CCA would need relevant customer and load data in order to conduct a meaningful investigation of CCA programs.

39. A CCA cannot notify customers of its intent to offer electrical service if it does not have access to relevant customer information.

40. In the CCA's effort to satisfy customer notice requirements, tax rolls are not a reasonable substitute for customer information held by utilities partly because property owners would not necessarily be a utility customer of record.

41. Nondisclosure agreements would provide reasonable protections against the disclosure by a CCA of a utility's customer information.

42. CCAs may need specific customer information in order to market energy services and tailor those services to individual customers or groups of customers.

43. CCAs need load data in order to develop cost-effective and reliable energy procurement strategies.

44. Customers would benefit from notification that contact information and usage data may be shared with the CCA and may not be disclosed to others.

45. A CCA phase-in or pilot program may facilitate the transfer of energy services from the utility to the CCA but may be costly.

46. Applying CCA-specific load profiles to ISO charges could increase liabilities to other customers.

47. Although developing CCA-specific load profiles may be costly, there may be simple ways to estimate them.

48. Boundary metering would help CCAs develop area load profiles.

49. Requiring a CCA to participate in an open season immediately would unreasonably delay initiation of service by CCAs because the Commission will not adopt guidelines for open seasons until Phase II of this proceeding.

Conclusions of Law

1. AB 117 provides the Commission discretion to determine which implementation costs should be allocated to individual CCAs and which of those costs should be allocated to ratepayers generally.

2. AB 117 defines transaction costs as those relating to metering, billing, and other customer services that are attributable to a single CCA.

3. Each utility should be permitted to establish balancing accounts for implementation costs incurred prior to the implementation of its next general rate case. Those balancing accounts should be eliminated once the Commission has authorized a related revenue requirement in that general rate case.

4. The utilities should be ordered to charge CCAs for transaction costs in tariffs that include charges based on incremental costs. The utilities should not be permitted to establish balancing accounts for CCA transaction costs that are recoverable in tariffs.

5. The utilities should not be permitted to “true-up” transaction costs included in tariffs but should be permitted to forecast those costs in general rate cases.

6. The utilities should be ordered to apply direct access tariffs for CCA transactions until the Commission has approved final CCA tariffs in this proceeding.

7. The utilities should be ordered to propose final tariffs for recovery of transactions costs from ratepayers within 60 days of the effective date of this order for consideration in Phase 2 of this proceeding.

8. CCA tariffs should unbundle elements of the billing and call center services tariffs so that CCAs are not charged for billing processes and customers services that are unrelated to CCA services and CCA customer billings.

9. AB 117 requires CCAs to pay for “opt-out” notifications mailed by the utilities to customers. The utilities should charge for these services in the CCA tariffs.

10. The costs of developing the initial "opt-out" procedures and infrastructure should be assumed by all ratepayers as an implementation cost.

11. The utilities should be authorized to charge customers a re-entry fee after those customers have transferred from the CCA to the utility as a bundled customer. That fee should reflect the administrative cost of transferring back to the utility.

12. The utilities should establish a CRS, consistent with this order and DWR's model, to allow the utilities to recover costs of power purchase commitments that become stranded as a result of the CCA initiating service. Such costs include DWR bond and power purchase contracts, utility power purchase commitments and balances in power purchase accounts but should not include costs that may have been avoidable or are not otherwise attributable to the CCA's customers. The CRS as described herein should be net of any existing "nonbypassable" surcharges for past liabilities that are included on all customer bills.

13. The utilities should be ordered to provide information about the components of the CRS and to provide a tariffed service to CCAs that would unbundle the components of the CRS on customer bills.

14. The Commission should consider in Phase II whether there may be opportunities for the utilities to allocate power to CCAs from DWR where a CCA requests.

15. Utilities should not be required to assume the risks of CCA forecasting errors or non-performance, and should propose tariff fees that reflect the cost of forecasting errors or non-performance attributable to the CCA.

16. Whether the utilities should be required to act as provider of last resort where CCA power supplies are inadequate is a matter for resolution in R.04-04-003.

17. AB 117 requires that retail end-use customers of CCAs to pay for the CRS.

18. The utilities should charge CCA customers directly for the CRS.

19. The utilities should propose ways to allocate the revenue shortfall from the baseline subsidy in appropriate ratemaking proceedings.

20. In the event customers of Norton Air Force Base are served energy by a CCA, SCE should exempt Norton Air Force Base from the CRS in amounts equal to the reductions it included in its forecasts to DWR and upon which DWR relied for long-term power purchases.

21. AB 117 does not permit cost-shifting of CCA CRS liabilities between utility bundled customers and CCA customers.

22. When read in conjunction with other provisions of AB 117, the requirement in Section 366.2(c)(7) that the Commission "inform" the CCA of its CRS liabilities is not a requirement that the CRS be capped or that utilities or utility bundled customers assume the risk for undercollections of CRS cost liabilities.

23. The utilities should establish balancing accounts for CRS costs and revenues and reconcile actual costs and revenues in the proceedings addressing the CRS for direct access customers, unless the Commission directs review of these costs and revenues in a different proceeding.

24. The utilities should not be required to assume the risk for CRS forecasts where CRS liabilities were reasonably incurred.

25. In the interim, the utilities should be ordered to apply the rates and cost recovery provisions of direct access tariffs to CCAs that begin operations prior to the Commission's approval of final CCA tariffs.

26. The utilities should file tariffs that implement an interim CRS of $.020/kWh, subject to true-up in 18 months or when the final CRS forecast is 30%

higher or lower than this amount. This CRS would not include costs already recovered by way of nonbypassable surcharges on existing utility bills for such liabilities as historic utility power liabilities or bond costs.

27. The utilities should be permitted to establish balancing accounts to track the costs of developing the infrastructure needed to implement the CCA program, and should allocate those costs to all ratepayers, as set forth herein. These balancing accounts should be eliminated following each utility's subsequent general rate case.

28. The utilities should be required to provide forecasts of CCA implementation costs in their general rate cases for recovery from all ratepayers.

29. The utilities should develop tariffs for transactions services to CCAs that include charges based on the incremental costs of each service but the utilities should not charge CCAs for services for which the utilities already recover costs in their revenue requirements, consistent with this order. The utilities should modify their CCA tariffs in general rate cases, consistent with the regulatory convention for adjustments to revenue requirements for other customers. In their general rate cases, the utilities may propose charges to CCA for transactions services that are currently included in utility revenue requirements and in such cases should propose offsetting reductions to other rates.

30. Section 366.2(c)(9) requires the utilities to provide all relevant information required by CCAs to "investigate, pursue or implement" meaningful programs. This requirement does not permit the utilities to deny CCAs access to relevant customer or load information.

31. Section 366.2(c)(13)(A) requires CCAs to provide customer notice of their intent to provide service, a requirement a CCA cannot satisfy without relevant customer information. Read in conjunction with Section 366.2(c)(9), this

requirement presumes that the CCA will have access to certain customer information held by the utility.

32. Section 366.2(c)(9) requires the provision of detailed billing and load data to CCAs that are investigating, pursuing or implementing CCA programs.

33. The utilities should require CCAs to sign nondisclosure agreements when they share confidential information about customers or electricity load and should require a county or city's chief administrative officer to attest that it is "investigating" or "pursuing" status as a CCA as a precondition to receiving confidential customer information.

34. Notices to prospective CCA customers should inform customers that the utility may share customer information with the CCA and that the information may not be used for any purpose other than to facilitate the provision of energy services to the customer by the CCA.

35. Utility tariffs should provide that the CCA must indemnify utilities from liability for the disclosure of confidential customer information in cases where the utility has take all reasonable precautions to prevent that disclosure.

36. AB 117 does not prohibit a phase-in or pilot program by the CCA.

37. Utility tariffs should offer a phase-in of a CCA program at cost.

38. The Commission will not determine which customers CCA should serve.

39. Utility tariffs should offer to develop an estimation of a CCA's load profile at cost, consistent with the proposal by SDG&E to adjust the system average load profile by use and climate.

40. Section 366.2(c)(18) requires the utilities to offer boundary metering. Utility tariffs should include an option for boundary metering to be provided at cost.

41. CCAs may initiate service prior to the Commission's adoption of open season guidelines.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) shall create balancing accounts for implementation costs incurred prior to cost recovery changes authorized in their respective general rate cases. The utilities shall not enter costs into those accounts after those changes to the revenue requirement in the general rate cases becomes effective.

2. PG&E, SDG&E, and SCE shall, within 60 days of the effective date of this decision, file tariffs that are substantively identical to those in effect for direct access customers and which shall apply in the interim to Community Choice Aggregators (CCAs) prior to the Commission's approval of final CCA tariffs.

3. PG&E, SDG&E, and SCE shall, no later than 60 days after the effective date of this order, serve tariffs on all parties to this proceeding regarding costs and terms of services for CCAs. Cost recovery proposed in those tariffs shall be based on incremental costs but the tariffs shall not include charges for services for which the utilities already receive remuneration in existing revenue requirements, consistent with this order. These draft tariffs will be considered in Phase 2 of this proceeding.

4. PG&E, SDG&E, and SCE shall, in their respective general rate cases, propose (1) a revenue requirement for CCA implementation costs and (2) changes to CCA tariffs for transactions including metering, billing, customer services and other services, which shall be authorized in the general rate case and

remain in effect until a subsequent general rate case order, consistent with this order.

5. PG&E, SDG&E, and SCE's proposed tariffs shall include (1) unbundled elements for billing and call center services tariffs in ways that assure CCAs are not charged for billing processes or customer services that are unrelated to CCA services and CCA customer billings; (2) an optional service to produce and mail opt-out notices to customers at cost; (3) a re-entry fee for customers who transfer from the CCA to the utility and which reflects the administrative cost of transferring the customer; (4) an interim cost recovery surcharge (CRS) set at $.020/kilowatt hour (kWh) and applying the terms and conditions set forth in this order, and which is subject to modification within the subsequent 18 months only if and when the CRS forecast is at least 30% lower than or higher than $.020/kWh; (5) an option to unbundle components of the CRS on customer bills, at cost; (6) provisions that would protect the utilities from assuming the risk of CCA forecasting errors or nonperformance at cost; (7) a service to provide back-up energy supplies and balancing services at cost; (8) a provision to charge CCA customers directly for CRS liabilities; (10) the establishment of a balancing account for CRS costs and revenues that shall be subject to reconciliation in Commission proceedings reviewing the Department of Water Resources (DWR) revenue requirement or other proceeding, as the Commission may direct; (12) the offer to provide access to all relevant customer information, billing information, usage and load information, consistent with this order and which shall be provided to the CCA at cost except that those information services already approved in D.03-07-034 shall be provided at no cost to the CCA; (13) a requirement that all confidential utility information shall be provided subject to nondisclosure agreement and a requirement that the chief administrative officer

of a city or county attest that the city or county is investigating or pursuing status as a CCA as a precondition of receiving confidential customer information; (14) a requirement that customer notifications about prospective CCA operations inform the customer that customer information may be provided to the CCA subject to nondisclosure for any purpose other than those related to facilitating the CCA's services; (15) a provision for CCAs to indemnify the utilities from liabilities associated with the CCA's disclosure of confidential customer information where the utility has taken all reasonable steps to prevent such disclosure; (16) an option to phase-in a CCA's program at the incremental cost of that option; and (17) an option to have the utility install meters at CCA boundaries, at cost.

6. In the event that the residents and businesses of Norton Air Force Base are served by a CCA for their energy requirements, SCE's proposed tariffs shall provide an exclusion from the CRS for Norton Air Force Base in amounts equal to the reduction it included in its forecasts to DWR and upon which DWR relied for long-term power purchases, consistent with this order.

7. PG&E, SCE, and SDG&E shall for Phase II of this proceeding develop a forecast for the CRS in their respective territories, consistent with this order, and serve a notice of availability of the forecast and work papers on all parties to this proceeding. Each cost component of the CRS shall be calculated and identified separately. Elements of the work papers that are confidential shall be provided subject to a standard nondisclosure agreement.

8. This proceeding remains open for the Commission's consideration in Phase 2 of final cost allocation and terms of services to CCAs and related issues as set forth herein.

9. In all respects, utility tariffs and practices shall permit CCAs to initiate service immediately following the filing of tariffs described in Ordering Paragraph 2.

10. This order is effective today.

Dated December 16, 2004, at San Francisco, California.

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APPENDIX B

ASSEMBLY BILL 117

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AB 117
Public Utilities Code

366.2. (a) (1) Customers shall be entitled to aggregate their electric loads as members of their local community with community choice aggregators.

(2) Customers may aggregate their loads through a public process with community choice aggregators, if each customer is given an opportunity to opt out of their community's aggregation program.

(3) If a customer opts out of a community choice aggregator's program, or has no community choice program available, that customer shall have the right to continue to be served by the existing electrical corporation or its successor in interest.

(b) If a public agency seeks to serve as a community choice aggregator, it shall offer the opportunity to purchase electricity to all residential customers within its jurisdiction.

(c) (1) Notwithstanding Section 366, a community choice aggregator is hereby authorized to aggregate the electrical load of interested electricity consumers within its boundaries to reduce transaction costs to consumers, provide consumer protections, and leverage the negotiation of contracts. However, the community choice aggregator may not aggregate electrical load if that load is served by a local publicly owned electric utility, as defined in subdivision (d) of Section 9604. A community choice aggregator may group retail electricity customers to solicit bids, broker, and contract for electricity and energy services for those customers. The community choice aggregator may enter into agreements for services to facilitate the sale and purchase of electricity and other related services. Those service agreements may be entered into by a single city or county, a city and county, or by a group of cities, cities and counties, or counties.

(2) Under community choice aggregation, customer participation may not require a positive written declaration, but all customers shall be informed of their right to opt out of the community choice aggregation program. If no negative declaration is made by a customer, that customer shall be served through the community choice aggregation program.

(3) A community choice aggregator establishing electrical load aggregation pursuant to this section shall develop an implementation plan detailing the process and consequences of aggregation. The implementation plan, and any subsequent changes to it, shall be considered and adopted at a duly noticed public hearing. The implementation plan shall contain all of the following:

(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.

(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) A 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.

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(4) A community choice aggregator establishing electrical load aggregation shall prepare a statement of intent with the implementation plan. Any community choice load aggregation established pursuant to this section shall provide for the following:

(A) Universal access.
(B) Reliability.
(C) Equitable treatment of all classes of customers.
(D) Any requirements established by state law or by the commission concerning aggregated service.

(5) In order to determine the cost-recovery mechanism to be imposed on the community choice aggregator pursuant to subdivisions (d), (e), and (f) that shall be paid by the customers of the community choice aggregator to prevent shifting of costs, the community choice aggregator shall file the implementation plan with the commission, and any other information requested by the commission that the commission determines is necessary to develop the cost-recovery mechanism in subdivisions (d), (e), and (f).

(6) The commission shall notify any electrical corporation serving the customers proposed for aggregation that an implementation plan initiating community choice aggregation has been filed, within 10 days of the filing.

(7) Within 90 days after the community choice aggregator establishing load aggregation files its implementation plan, the commission shall certify that it has received the implementation plan, including any additional information necessary to determine a cost-recovery mechanism. After certification of receipt of the implementation plan and any additional information requested, the commission shall then provide the community choice aggregator with its findings regarding any cost recovery that must be paid by customers of the community choice aggregator to prevent a shifting of costs as provided for in subdivisions (d), (e), and (f).

(8) No entity proposing community choice aggregation shall act to furnish electricity to electricity consumers within its boundaries until the commission determines the cost-recovery that must be paid by the customers of that proposed community choice aggregation program, as provided for in subdivisions (d), (e), and (f). The commission shall designate the earliest possible effective date for implementation of a community choice aggregation program, taking into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the commission.

(9) All electrical corporations shall 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. Electrical corporations shall continue to provide all metering, billing, collection, and customer service to retail customers that participate in community choice aggregation programs. Bills 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.

(10) (A) A city, county, or city and county that elects to implement a community choice aggregation program within its

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jurisdiction pursuant to this chapter shall do so by ordinance.

(B) Two or more cities, counties, or cities and counties may participate as a group in a community choice aggregation pursuant to this chapter, through a joint powers agency established pursuant to Chapter 5 (commencing with Section 6500) of Division 7 of Title 1 of the Government Code, if each entity adopts an ordinance pursuant to subparagraph (A).

(11) Following adoption of aggregation through the ordinance described in paragraph (10), the program shall allow any retail customer to opt out and to continue to be served as a bundled service customer by the existing electrical corporation, or its successor in interest. 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. Once enrolled in the aggregated entity, any ratepayer that chooses to opt out within 60 days or two billing cycles of the date of enrollment may do so without penalty and shall be entitled to receive default service pursuant to paragraph (3) of subdivision (a). Customers that return to the electrical corporation for procurement services shall be subject to the same terms and conditions as are applicable to other returning direct access customers from the same class, as determined by the commission, as authorized by the commission pursuant to this code or any other provision of law. Any reentry fees to be imposed after the opt-out period specified in this paragraph, shall be approved by the commission and shall reflect the cost of reentry. The commission shall exclude any amounts previously determined and paid pursuant to subdivisions (d), (e), and (f) from the cost of reentry.

(12) Nothing in this section shall be construed as authorizing any city or any community choice retail load aggregator to restrict the ability of retail electricity customers to obtain or receive service from any authorized electric service provider in a manner consistent with law.

(13) (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:

(i) That they are to be automatically enrolled and that the customer has the right to opt out of the community choice aggregator without penalty.

(ii) The terms and conditions of the services offered.

(B) 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).

(C) 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.

(14) The community choice aggregator shall register with the commission, which may require additional information to ensure compliance with basic consumer protection rules and other procedural matters.

(15) Once 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.

(16) Once 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.

(17) An electrical corporation shall recover from the community choice aggregator any costs reasonably attributable to the community choice aggregator, as determined by the commission, of implementing this section, including, but not limited to, all business and information system changes, except for transaction-based costs as described in this paragraph. Any costs not reasonably attributable to a community choice aggregator shall be recovered from ratepayers, as determined by the commission. All reasonable transaction-based costs of notices, billing, metering, collections, and customer communications or other services provided to an aggregator or its customers shall be recovered from the aggregator or its customers on terms and at rates to be approved by the commission.

(18) At the request and expense of any community choice aggregator, electrical corporations shall install, maintain and calibrate metering devices at mutually agreeable locations within or adjacent to the community aggregator's political boundaries. The electrical corporation shall read the metering devices and provide the data collected to the community aggregator at the aggregator's expense. To the extent that the community aggregator requests a metering location that would require alteration or modification of a circuit, the electrical corporation shall only be required to alter or modify a circuit if such alteration or modification does not compromise the safety, reliability or operational flexibility of the electrical corporation's facilities. All costs incurred to modify circuits pursuant to this paragraph, shall be born by the community aggregator.

(d) (1) It is the intent of the Legislature that each retail end-use customer that has purchased power from an electrical corporation on or after February 1, 2001, should bear a fair share of the Department of Water Resources' electricity purchase costs, as well as electricity purchase contract obligations incurred as of the effective date of the act adding this section, that are recoverable from electrical corporation customers in commission-approved rates. It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers.

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(2) The Legislature finds and declares that this subdivision is consistent with the requirements of Division 27 (commencing with Section 80000) of the Water Code and Section 360.5, and is therefore declaratory of existing law.

(e) A retail end-use customer that purchases electricity from a community choice aggregator pursuant to this section shall pay both of the following:

(1) A charge equivalent to the charges that would otherwise be imposed on the customer by the commission to recover bond related costs pursuant to any agreement between the commission and the Department of Water Resources pursuant to Section 80110 of the Water Code, which charge shall be payable until any obligations of the Department of Water Resources pursuant to Division 27 (commencing with Section 80000) of the Water Code are fully paid or otherwise discharged.

(2) Any additional costs of the Department of Water Resources, equal to the customer's proportionate share of the Department of Water Resources' estimated net unavoidable electricity purchase contract costs as determined by the commission, for the period commencing with the customer's purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the Department of Water Resources.

(f) A retail end-use customer purchasing electricity from a community choice aggregator pursuant to this section shall reimburse the electrical corporation that previously served the customer for all of the following:

(1) The electrical corporation's unrecovered past undercollections for electricity purchases, including any financing costs, attributable to that customer, that the commission lawfully determines may be recovered in rates.

(2) Any additional costs of the electrical corporation recoverable in commission-approved rates, equal to the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs attributable to the customer, as determined by the commission, for the period commencing with the customer's purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation.

(g) (1) Any charges imposed pursuant to subdivision (e) shall be the property of the Department of Water Resources. Any charges imposed pursuant to subdivision (f) shall be the property of the electrical corporation. The commission shall establish mechanisms, including agreements with, or orders with respect to, electrical corporations necessary to ensure that charges payable pursuant to this section shall be promptly remitted to the party entitled to payment.

(2) Charges imposed pursuant to subdivisions (d), (e), and (f) shall be nonbypassable.

(h) Notwithstanding Section 80110 of the Water Code, the commission shall authorize community choice aggregation only if the commission imposes a cost-recovery mechanism pursuant to subdivisions (d), (e), (f), and (g). Except as provided by this subdivision, this section shall not alter the suspension by the commission of direct purchases of electricity from alternate providers other than by community choice aggregators, pursuant to Section 80110 of the Water Code.

(i) (1) The commission shall not authorize community choice

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aggregation until it implements a cost-recovery mechanism, consistent with subdivisions (d), (e), and (f), that is applicable to customers that elected to purchase electricity from an alternate provider between February 1, 2001, and January 1, 2003.

(2) The commission shall not authorize community choice aggregation until it submits a report certifying compliance with paragraph (1) to the Senate Energy, Utilities and Communications Committee, or its successor, and the Assembly Committee on Utilities and Commerce, or its successor.

(3) The commission shall not authorize community choice aggregation until it has adopted rules for implementing community choice aggregation.

(j) The commission shall prepare and submit to the Legislature, on or before January 1, 2006, a report regarding 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.

(END OF APPENDIX B)