BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Portions of AB117 Concerning Community Choice Aggregation	R.03-10-003 (filed October 2, 2003)

COMMENTS OF LOCAL POWER ON THE PHASE I WORKSHOP ON THE CUSTOMER RESPONSIBILITY SURCHARGE, TARIFFS AND COST-RECOVERY MECHANISMS AND INFORMATION REQUESTS

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A. SUMMARY

The January 14 Workshop's goal is to develop common understandings of related issues, determine common objectives, and reach agreements where possible in order to reduce the need for evidentiary hearings in R0310003. Questions:

> **1. CRS - cost elements that should be included in fulfillment of AB117; allocation of responsibility for the costs and whether they are nonbypassable.**
> **2. CRS exemption for baseline residential customers - whether the utilities should pass along these subsidies to CCA customers and, if so, how to accomplish that.**
> **3. Utility transition and transaction costs - keeping utilities and their customers indifferent to the costs of implementing the CCA portions of AB117**
> **4. Meter, billing, and distribution costs.**
> **5. Utility customer information - information CCAs and prospective CCAs need to determine viability of CCA service and promote good customer service and reliability costs.**

B. ANSWERS

1. CUSTOMER RESPONSIBILITY SURCHARGE (CRS)
The Commission's existing Direct Access (DA) CRS analysis does not apply to Community Choice Aggregations (CCA). As customers are not currently contributing to any undercollection, and are in fact financing the DA CRS undercollection, it is not appropriate to take the DA CRS analysis and rules. Instead, CRS analysis and rules are needed for the Commission to calculate a CCA CRS. It The CCA CRS may be lower than the DA CRS, and the Commission should avoid unfair cost shifting to CCA customers.

The OIR correctly notes that costs "not reasonably attributable to a community choice aggregator shall be recovered from ratepayers." (OIR at p. 9.) Local Power agrees that it is appropriate and consistent with the statute to limit the assessment of transaction charges on CCAs to those costs that are specifically attributable to a specific CCA.

The CRS should reflect *actual costs attributable* to a CCA's proposed Implementation Plan as required by 366.2(c)(7) of the Public Utilities Code:

> "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)."

Clearly AB117 outlines a case-by-case process in which a specific CCA submits a specific implementation plan to the Commission, based on which the CPUC provides a specific CRS assignment.

This is not consistent with a uniform CRS modeled on the Commission's DA CRS calculation based on the "indifference principle." In that case, the Commission determined that bundled customers should be indifferent to suspension of DA as of September 20, 2001 rather than the earlier date of July 1, 2001. The DA CRS was thus calculated based on the additional costs to bundled service customers that resulted from the migration of load from bundled service to DA during that time period. The Commission then capped the level of the DA CRS at 2. 7 cents/kWh to spread the recovery of the undercollection over several years.

A uniform CRS should not be applied to customers of CCAs. Geographic, temporal, energy resource and other distinctions are statutory factors outlined in AB117's Implementation Plan-based CRS calculation process. A uniform CRS is inconsistent with statute, and would hobble the initiation of the CCA program in the name of convenience to the Commission's exiting policies.

In addition, CRS Calculation should be sensitive to energy efficiency and renewable resource development by CCAs, and should ensure that its CCA CRS not only avoid zero sum game cost-shifting but also *credit* the monetary and public health benefits of renewable resource and energy efficiency development. We share others' concerns that the only discussion of renewables in the OIR is a statement that the issue will be addressed in the generation procurement case R.01-10-024). Given that the costs attributable to ratepayers differs according to different resource decisions, it is critical that the CCA CRS reflect such resource decisions as outlined in CCA Implementation Plans that come before them.

To provide a "customized rate," or set of rates that varies by CCA, the Commission would not create unnecessary complexity nor administrative impracticality. Indeed the principal opportunity of Community Choice is to design energy services that match local conditions, needs and community values. A one size fits all approach would result in a failure to facilitate Community Choice transactions between CCAs and Electric Service Providers (ESPs).

The Commission should consider approaches, such as: 1) classifying procurement contracts or generation costs by date and energy resource portfolio, and making an individual CCA's customers only responsible for contracts and costs classified as in existence before the CCA's formation date (so-called "vintaging"); 2) allowing for the allocation of specific DWR contracts to individual CCAs; or 3) other Implementation Plan elements that individual CCAs may innovate in order to minimize the CRS that should be reasonably attributable to their customers.

A uniform rate approach would inappropriately export the Commission's cost-plus and DA-based practice of setting rates for residential customers based on the average cost of serving all residential customers throughout the service area, without reflecting or seeking to account for regional differences, portfolio decisions or other details of a CCA's Implementation Plan. For example, except for baseline differences, customers residing in San Francisco take electric service under the same rate schedule as those living in Vacaville, even though any or all of the following variables of their Implementation Plans could be different:

> (A) An organizational structure of the program, its operations, and its funding.
> (B) Ratesetting and other costs to participants.
> ©) 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"[Public Utilities Code 366.2(c)(3)].

Nothing prevents third parties from being parties to DWR contracts, renewable resource developers, ESCOs or other entities that will present unique load forecasting information that is critical to maintaining a reliable and secure energy supply in California.

Furthermore, AB117 provides for CCAs to improve their load profiles, administer and tailor energy efficiency programs based on customer patterns of usage, and develop renewable resources.

AB117 establishes the right of Community Choice Aggregators to administer locally-paid energy efficiency funds to competitive installers/operators. Moreover, California municipalities now can improve their load profiles as a bundled component of their ESP service. AB117 specifically requires that load profile improvement is a statutory criterion of a CCA's data request to its utility:

> "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" [AB117, Public Utilities Code Section 366.2©)(9)].

The integrated planning of not only grid commodity but also load shaping improvements measurable at the substation, requires a more creative and flexible use of data more appropriate to the century we are, after all, already in. There is first the legal requirement that utilities must provide the data to the CCA for this purpose. Second is AB117's requirement that the utilities must even install, maintain and calibrate new interval meters and report their data to the CCA at its request and expense (Public Utilities Code Section 366.2(c)(18). It is well known that San Francisco and the other California cities seeking to implement Community Choice are primarily concerned with the load shaping side of the Community Choice opportunity. Thus it is critical for the jurisdictional authority and curtailed load forecasting capabilities of the Commission that the CRS be calculated on a case-by-case basis

The failure to integrate CRS calculation with gatekeeping is already a problem at the Commission and deserves urgent action. As R0310003 begins to look at how to calculate the CRS, R01-10-024 is now on the verge of approving a framework for utility procurement based on AB57 of 2002. If approved, the electric procurement framework will impose a substantial non-bypassable surcharge and even make decisions about the responsibilities of CCAs in paying for reserve margins.

The Commission must connect the dots between its ongoing utility procurement proceeding and community aggregation, which should not be difficult as both proceedings share the same Assigned Commissioner (Peevey). Indeed, Local Power has requested that R01-10-024 delay its electric utility procurement framework six months to allow time for R0310003 to catch up. It is critical that the Commission establish an evidentiary record of prospective CCAs who wish to depart from utility procurement, so that a rational, holistic and balanced gatekeeping of utility procurement with CCA can be undertaken.

The utilities have asked for a gatekeeping of departing and returning load, and this is correct. But on the other hand it is equally critical - to apply the indifference principle to CCA customers - that the gatekeeping be also used to minimize electric procurement impacts on CCAs and not merely “calculate” them while blindly rate-basing utility contracts. We do not disagree with the utilities will need time to process transfers of customers, upgrade business and information systems - and will need protocols for returning customers. But this must be a two-way street.

Finally, AB117 allows CCAs to design local programs according to local conditions, and requires utilities to provide data to CCAs on their constituents “electricity needs and patterns of usage”[((Section 366.2(c)(9)]. AB117 also orders the Commission to direct the administrator of energy efficiency funds to “work with the community choice aggregator, to provide advance information where appropriate about the likely impacts of energy efficiency programs and *to accommodate any unique community program needs by placing more, or less, emphasis on particular approved programs”*[PUC Code Section 381.1(c))]. While also protecting the effectiveness of broader statewide or regional programs, AB117 clearly provide for local communities to plan for the shaping their aggregated loads - an activity that directly impacts and is directly impacted by, load forecasting and utility procurement.

These provisions for load shaping clearly require the Commission to follow the Implementation Plan CRS calculation process outlined in AB117. Under DA CRS decision 02-11-022 the Commission rightly rejected establishing different CRS rates for individual DA customers "based on pro rata allocations for the specific period of time that each DA customer took bundled service." Under Community Choice, the gatekeeping process outlined by AB117 makes the determination based on the Implementation Plan adopted by a CCA's governing board, not based on what a period of time a customer departs. And whereas the Commission's decision to apply a uniform CRS identified "practical limitations in (the utility) billing system that would make such customer-by-customer determinations of charges impractical and unduly costly," Community Choice replaces customer-by-customer determinations with a *single* calculation of a CRS to be assigned to the CCA based on its community-wide, city council-adopted Implementation Plan.

Recognizing the case-by-case nature of Community Choice Aggregation Implementation Plans.
Multiple tracking and multiple rates should not be required because the Commission is not authorized to regulate rates, but merely to assign a collective CRS. Thus it would not significantly increase implementation requirements, time or cost. One community's success in arguing for a lower CRS would not mean higher overall costs to the extent that the Commission accurately calculated the costs reasonable attributable to the CCA.

An issue related to Implementation Plan-based CRS calculation is the critical need to allow interested CCA's to seek assignment of DWR contracts to CCAs as an alternative to shouldering the associated CRS. As currently drafted the OIR benefits the UDC by subsidizing the avoided cost by passing it to CCA ratepayers, but still allowing the UDC the right to the power to be resold or delivered to customers. Under this framework the CCA members are paying twice for something they only get once (electricity) while the utility is "given" the resulting capacity. The power supply arrangements should transfer with the obligation to pay the CRS at the current market value at the time the CCA takes possession of the customers if mutually agreeable to both the CCA and the UDC. If not acceptable, the CCA should be "credited" with cost of the electricity supply that does not transfer. This might entail the utility scheduling trades with the community choice aggregator's scheduling coordinator for a percentage of the its load requirements. The CCA could pay for the contract electricity based on the average cost of the DWR contracts. This arrangement may benefit the CCA, while fully compensating remaining bundled service customers for the actual cost of the DWR contracts. In particular, to the extent that some DWR contracts include take-or-pay capacity payments, it may be more cost effective to take the energy at the combined capacity/energy cost than to pay the unavoidable capacity payment through the CRS, without getting the associated energy.

It is in the interest of the State of California that the DWR CRS be reduced through an opt-out process that would relieve ratepayers of the burden of the contracts while also enriching the availability of competitive supply in California. Liability for a utility's DWR contracts can be assumed by the CCA to reduce the actual costs attributable to its load departure, thus reducing that a particular CCA's CRS. Given successful negotiation among parties, it is entirely feasible for a CCA to assume all or portions of a DWR contract(s) It should be left to CCAs and ESPs to seek opportunities to match loads between the DWR contract and the CCA, such that a contract could be signed. Finally, anticipated disagreements between CCAs and utilities on which contracts should be assigned to the CCA should be mitigated by the Commission's authority to set the resulting CRS to reflect any costs resulting from an imperfect matching of contract and load. The indifference standard would be protected, the state's energy resources diversified. Local Power believes the CPUC should adopt rules encouraging this approach.

In short, the "indifference principle" should be applied both ways by the Commission - not only to the utilities' bundled service customers, but the CCA customers who are departing not as individual large commercial and industrial elites but as whole communities seeking new "bundled" services who share the same local democratic institutions, Control Areas, grids and microgrids, substations, and load conditions.

Thus, the Commission should not calculate a uniform CRS for CCA customers based on the amount of load that leaves bundled service for community aggregation. As the Commission decided in DA CRS decision 02-11-022 to reject establishing different CRS rates "based on pro-rata allocations for the specific period of time that each DA customer took bundled service." The a uniform CRS cannot be adjusted periodically, though DWR and utility stranded costs may increase or decrease with changes in the market. Instead, the Implementation Plan-based CRS calculation process outlined in AB117 is the only process that will ensure mutual "indifference" by evaluating the particular plan the CCA has put on the table.

A common misunderstanding of Community Choice Aggregation is that it will increase regulatory complexity. In fact it does the opposite. In Ohio over a million customers are served by just three CCAs. From an administrative perspective the burden of assigning a CRS to three CCAs is insignificant compared to the burden of assigning a CRS to a million customers individually.

Indeed, as assigning a CRS to Implementation Plans is the principal regulatory authority granted the Commission by AB117, a case-by-case approach to the CRS will give the Commission needed leverage in influencing CCA Implementation Plans and more accurately forecasting load conditions in California. Where unanticipated costs arise, the Implementaiton Plan-based CRS would enable the Commission to have more authority in integrating utility procurement with CCA departures so as to both influence resource planning decisions and minimize the costs to both CCA and bundled service customers. In contrast, a uniform CRS would limit the Commission to a rubber stamp role with CCAs, put pressure on the Commission to reverse its 02-11-022 decision, and result in poorer forecasting accuracy and ultimately higher costs to all consumers.

Moving along, there is the issue of whether the CRS cap on DA should be applied to CCAs. Local Power feels that in any case CCAs should not be forced to pay a higher CRS than a DA customer. First, as stated above, CCA imposes fewer costs than DA customers do. Second, whereas DA customers are nearly all large commercial and industrial customers, CCA customers are predominantly small residential and business customers. The Commission should not put CCA in a disadvantage to DA customers or the result could be a high opt-out rate for large customers seeking the capped rate. The results would be both regressive and chaotic.

Placing the same CRS cap on CCA that is enjoyed by DA customers would not require that bundled service customers be forced to make “loans” to community aggregation customers any more than any other existing non-bypassable surcharge constitutes a “loan.” Just as DA successfully argued in R. 02-01-011 that their cost responsibility surcharge should be “capped” at 2.7 cents, in order to “preserve DA” and to avoid DA contracts becoming uneconomic, the same need exists for AB117, and whereas DA is now suspended, AB117 is law; thus there is no basis for discrimination. While concerns about after-the-fact applicability of DA are not present, a faithful implementation of AB117 requires that CCA not be subjected to prejudicial CRS conditions.

Finally, and most importantly, AB117 establishes a ***gatekeeping*** process to allow for CCA with a minimum cost impact:

> 366.2©) (7) “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.”

Thus, while under AB117, CCAs and/or their customers are required to pay the implementation costs for community aggregation that are *reasonably attributable* to the CCA and all reasonable transaction-based costs of notices, billing, metering, collections, communications or other customer services provided to a CCA or its customers, the Commission should adapt its mechanisms not merely to *calculate* the assignment of costs but also to *schedule* and *gatekeep* among CCAs and utility procurement in a manner that minimizes costs to prospective CCA ratepayers resulting from utility procurement contracts as well as costs to utility bundles service customers resulting from CCA load departures.

That Chapter 835 and 838 of 2002 clearly intended both activities to co-exist, it is critical that the Commission integrate related aspects of R0110024 and R0310003. With R0110024 now considering approval of a multi-year utility procurement framework on January 22 that would impose a massive new CRS on CCAs, this issue becomes clearer. Unless the Commission embraces its new gatekeeping role, utility procurement is on a crash course with CCA-based ESP procurement. We need to get on the same page and establish an even playing field that allows for utility procurement alongside CCA.

2. CRS EXEMPTION FOR BASELINE RESIDENTIAL CUSTOMERS

The OIR's discussion is silent on the issue of the ABIX subsidy, which cannot be eliminated through rate design since it is based on a public policy of protecting residential ratepayers. The Commission should preserve the existing Water Code section 80110 exemption for 130% of baseline usage for residential customers, prohibiting the Commission from increasing electricity generation charges for these customers.

Unless it can somehow be integrated into the CRS as a credit for communities that are predominantly residential, CCA's with predominantly residential ratepayers will face unfair and major price barriers, making the CRS communities would have to charge for residential load under 130% of baseline more expensive than what the IOUs can offer. This improper subsidization should be accounted for in the CCA CRS, calculating a separate CRS for usage below 130% of baseline.

Thus, the AB 1X subsidy to residential customers should move with those customers whether served by a utility or CCA. Moreover, the need to calculate the subsidy in a time-specific manner underscores the need for and appropriateness of a case-by-case, CCA Implementation Plan-based CRS calculation by the Commission. With different communities having very different load factors from each other, calculating a separate CRS for each CCA that would uniquely capture
both its load factor and percentage of residential customers is needed and would NOT be administratively burdensome, because of the countervailing efficiencies introduced through economies of scale (the smallest CCA in the United States has 100,000 customers, the largest 650,000.

Questions about the order in which these calculations should be made and the potential appearance of unfairness of ultimately reflect on the ironic truth of the matter which is that the uniform CRS secretly imposes dramatic unfairness while appearing fair, whereas a case-by-case Implementation Plan-based CRS by the Commission might raise more controversy but is inherently more based on actual costs attributable to the CCA load departure, and is therefore inherently more fair to ratepayers.

An Implementation Plan-based CRS would be calculated based on the DA, distributed generation, municipal, and CCA load at the time of certification, would be time-differentiated to account for differences in load factor between different entities included in the calculation, and would be used by the Commission to plan electric utility procurement. Then a separate adjustment to this CRS could be developed that would account for the difference in the percentage of tier 1 and tier 2 residential load between the IOU and CCA.

The level of the CRS for CCA customers would not be the same as that for DA customers because "DA customers assume certain undercollection that may not logically apply to CCA customers and may not be liable for certain future costs. The main past undercollection that SCE's DA customers still pay for is the Historic Procurement Charge. The CRS for CCA load should not include this element because utilities' bundled customers (who are the potential future CCA load) have already paid

3. UTILITY TRANSITION AND TRANSACTION COSTS

While it is true that the myriad processes related to implementing Community Choice Aggregation will incur incremental start-up and ongoing implementation costs for the services the utilities are required to provide for community aggregation, it is critical that any resulting tariffs or mechanisms charging CCA customers for these costs reflect an accurate attribution. As directed in the OIR, the utilities will propose tariffs and mechanisms to recover these costs.

The utilities' costs of implementing the first CCA will impose an up-front cost on the utility, but many of the changes made will clearly benefit (1) all ratepayers that subsequently implement CCA, (2) bundled service customers, and will even benefit (3) the utilities themselves. The Commission should take a flexible net-based approach to monetizing benefits and allocating fees and credits.

An actual "attribution" of cost makes it inevitable that utilities should indeed be made to "finance" these costs for CCAs and their customers by allowing the recovery of such costs to be deferred over a period of time. CCAs should not be prepared to shoulder these costs to the utility unilaterally at the time the costs are incurred. Scheduling and allocating obligations for the full recovery of these costs is an appropriate gatekeeping mechanism that would not result in an improper shifting of community aggregation costs and burdens to bundled service customers.

The utilities must learn to live with the presence of the competitive forces created by AB117 rather than requiring a prejudicial treatment of departing customers under the auspices of “protecting” their (otherwise captive) customers. On the other hand, the Commission should recognize the fact that the ability of customers to depart from utility procurement in a reasonable window is a benefit to all ratepayers. Indeed, the need to provide LSEs with an incentive to enter into contracts with terms long enough to allow for financing of new generation sources cannot justify illegal or unwise restrictions on departure any more than it justifies making ratepayers responsible for those investments.

- TARIFFS AND MECHANISMS

The commission is addressing cost-recovery issues for DA customers in R.02-01-011and has adopted a cost-responsibility surcharge (“CRS”) for DA customers in that proceeding. AB117 requires the Commission to determine whether its adopted cost-recovery mechanisms for DA customers are sufficient to comply with AB117 and, if so, to submit its report to the Legislature.

Local Power generally supports a modified application of existing DA rules to CCAs based upon the peculiar attributes and efficiencies of CCA. Some of these rules, rates and protocols can and should be adapted to CCA transactions; yet significant differences between direct access and CCA should be considered in establishing the rules for CCA implementation.

The Commission should make changes to reflect CCA’s greater efficiency and thus reduced transaction costs compared to DA transactions. The scale, simplicity and geographic concentration of the CCA customer base likely presents substantial opportunities for efficiency improvements in the account transfer process. CCAs’ will switch hundreds, thousands, tens of thousands, hundreds of thousands, or even millions of accounts in a single contiguous group rather than processing each customer one at a time.

Changes to the tariff rules should also reflect CCAs greater cost benefits to both the utilities’ retained bundled service customers, both in the form of creating downward competitive price pressures, leveraging investment in infrastructure (through CCAs long-term contracts) and offering formerly captive large and small ratepayers a permanent non-captivity option.

Changes should also reflect CCA’s superior benefits to residential and small commercial customers over DA. Considering that residential customers and small businesses will be the principal constituents of CCA compared to DA (which served primarily large commercial and industrial customers), CCA “cost” calculations should incorporate these benefits that will now occur across ratepayer classes. Among these benefits is a more equitable opportunity for bundled service customers of all classes to have recourse to competitive suppliers. The availability of competitive ESPs to residential and small businesses will also offer competitive pressure for the utilities to limit their own rate increases or face an increase in customer load departures. Clearly this was the intention of the legislature and governor in making Community Choice (AB117, Chapter 838) law on the same day it made utility procurement (AB57, Chapter 835) law - September 24, 2002.

If the CPUC determines that a different set of CRSs should be applied to CCAs relative to those applicable to DA customers, then it would be appropriate to re-evaluate all of the direct access transaction fees to ensure that they properly reflect the actual costs associated with providing service to a CCA.

- NOTIFICATION & OPT-OUT

If a CCA requests its utility to notify customers of the community aggregation program, the utilities should be required to use their monthly electric bill for such notifications in order to minimize the associated costs. This is clearly the least-cost option and requires only basic business and information system upgrades to accommodate. Rather than overcharge CCA after CCA for an expensive notification process, the Commission should order the appropriate upgrades and share associated costs equally among CCA and bundled service customers. Direct mailers to all customers within the CCA's jurisdiction impose unnecessary costs that should not be recoverable by utilities. Utilities should be required to make the necessary business and information system changes to provide the capability of processing an opt-out "check" mark on the utility bill, process the opt-out information and send a confirmation to the customers. Because CCAs are a "communitywide electricity buyers' program" [Section 381.1(a)] and not ESPs, there is no justification for the added cost of employing an independent third party to manage or verify the opt-out process. Community Choice is not "slamming."

- DATA

Existing DA requirements for ESPs should remain the ESP's obligation before it can provide community aggregation service to the CCA's customers. The DA should place technical requirements on the ESP, not the CCA except voluntarily:

CCAs should submit an executed Service Agreement. The CCA or ESP should satisfy any applicable credit-worthiness requirements as determined by their Service Agreement and as determined by the Commission. The CCA or ESP must satisfy applicable Electronic Data Interchange (EDI), requirements, including:

a. The CCA or ESP must complete all necessary electronic interfaces for the CCA and utility to communicate for DASR, other data exchange and general communication purposes.

b. The CCA or ESP must have the ability to exchange data with SCE via the internet. Alternative arrangements may be allowed upon mutual agreement between the utility and the CCA.

c. The CCA or ESP must have the capability of performing EDI and enter into appropriate agreements regarding the exchange of billing information.

- CUSTOMER RE-ENTRY

The OIR proposes to "apply to CCA customers the re-entry fees assumed by DA customers returning to utility service". It then states "The utilities currently do not impose re-entry fees." In lieu of re-entry fees, the OIR appears to require CCA customers who return to utility service to receive spot prices for the first six months after their return.

The OIR proposes that the existing rules applicable to DA customers who terminate direct access service apply to CCA customers. We agree.

Those rules require a customer to provide notice of return to bundled service at least 6 months in advance. If customers are returned by CCA prior to expiration of 6-months notice they would pay a transitional price. The OIR proposes that the CCA notify the customers of program termination twice during the 60 day period before termination and explain the customers' liability for the spot prices. The OIR also proposes that the CCA registration packet include a service agreement with the utility, a signed agreement with a scheduling coordinator authorized by the ISO, and evidence of a bond or insurance adequate to cover re-entry fees.

No new charges should be imposed on Community Choice Aggregators that are not imposed on DA customers. The CCA may not be required to reimburse the utilities and post a bond or insurance for these extraordinary costs," as this option may be carried by either the CCA or its ESP pursuant to 394.25(e):

> "If a customer of an electric service provider or a community choice aggregator is involuntarily returned to service provided by an electrical corporation, any reentry fee imposed on that customer that the commission deems is necessary to avoid imposing costs on other customers of the electric corporation ***shall be the obligation of the electric service provider or a community choice aggregator***, except in the case of a customer returned due to default in payment or other contractual

> obligations or because the customer's contract has expired. As a condition of its registration, an electric service provider or a community choice aggregator shall post a bond or demonstrate insurance sufficient to cover those reentry fees. In the event that an electric service provider becomes insolvent and is unable to discharge its obligation to pay reentry fees, the fees shall be allocated to the returning customers" (My emphasis).

AB117 requires that any re-entry fees be the same as those applied to DA customers. Under AB117 re-entry fees are to reflect the costs of re-entry. Section 366.2©)(11) of the Public Utilities Code also states that customers that return to the utility for procurement services shall be subject to the same terms and conditions as are applicable to other returning DA customers.

Thus the "indifference principle" should be applied to all customers involved in the cost calculation of a CCA load departure. The cost of re-entry should not be calculated solely based on the impacts to the utilities' retained customers, but should also consider the impacts on CCA customers. Given the Universal Service requirement of AB117, Community Choice load departures do not involve large commercial and industrial customers departing at the expense of small customers, but, rather, whole communities of small and large customers availing themselves of a legal option to manage their own procurement.

It is not acceptable to calculate a re-entry fee exclusively based on the amount necessary to keep bundled customers indifferent if its procurement costs for bundled service customers increase significantly as a result of re-entry to bundled service by a large amount of community aggregation load. A calculation based on how much bundled service rates will rise if community aggregation load returns at various percentages (e.g., 5%, 10%, 15%, etc.) of total bundled service load would thus discriminate against departing customers.

As there are currently no re-entry fees set by the Commission or charged to customers returning to UDC service from DA, this clearly runs the risk that utilities may to charge any amount they want for this fee once they decide to implement it. The Commission should approve any utility DA re-entry fee before it may be implemented.

Finally, a advance notice of return/departure and a rolling commitment upon return to bundled service for its procurement planning purposes is a good starting point, but ultimately should be decided as part of the overall gatekeeping role outlined in these comments.

4. ACCOUNTING, BILLING AND METERING

The lower transaction costs, credibility and efficiency of Community Choice should allow IOUs to charge less for accounting, billing and meter reading services. A CCA will occupy one geographically contained region of an IOU's service territory and it is likely that almost all of the retail customers within that geographic region will be CCA customers. This makes for an economy of scale, with regard to IOU support services, that is not present with a DA service customer arrangement.

ESPs also sign up DA customers based on customer response which could occur anywhere within an IOU service territory with the result that direct access service requests (DASRs) tended to take much more individual attention from the IOU and were processed relatively infrequently. However CCAs will submit one request for hundreds of thousands of account transfers in a single geographic region.

The IOUs should be able to charge CCAs much less than they charge ESPs for consolidated utility billing services. For example PG&E's existing E-ESP tariff bills ESP's 70 cents per service account per billing cycle for the energy supply portion of the bill. With hundreds of thousands of accounts in the average CCA, this one-off system is charged hundreds of thousands of dollars per months or millions per year - which might be significantly reduced based on
the economies of scale enabled through consolidated processing of thousands of accounts as a single group.

The OIR states that the utilities should propose specific tariff language to meet the requirements of Section 366.2(

c)(18), which require the utility to instal, maintain and calibrate metering devices at mutually agreeable locations within or adjacent to the CCA's political boundaries at the request and expense of the CCA. Section 366.2(c)(18) also states that if the CCA requests a metering location that would require alteration or modification of a circuit, the utility shall only be required to alter or modify a circuit if the alteration or modification does not compromise the safety, reliability or operational flexibility of the electrical corporation's facilities. All costs incurred to modify circuits are to be paid by the CCA.

5. UTILITY CUSTOMER INFORMATION

In addition to the installation of load-monitoring meters, AB117 requires the utilities to cooperate "fully" with CCAs, including "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" (PUC Section 366.2(c)(9). These are clearly intended to allow for CCA load shaping purposes.

The OIR invites parties to comment on whether the information requirements adopted in D.03-07-034 in the energy efficiency proceeding R.01-08-028 are adequate for purposes of Section 366.2(c)(9). Local Power believes the information identified in D.03-07-034 is NOT sufficient to meet the requirements of section 366.2c9 and to enable CCAs to investigate and pursue community aggregation as outlined in AB117. Commission decision D.03-07-034, specified information to be made available by the investor-owned utilities (IOUs) to cities, counties and CCAs in Attachment C:

SEMPRA shall provide aggregate annual usage data broken out by city, zip code and customer and rate classes, on a monthly basis, Public Goods Charge customer payments by zip code and city, Quarterly or monthly aggregated participation data already tracked for Commission reports, Aggregated annual usage data for programs that are not customer specific (for example, information programs), the proportional share in a CCA's territory or proposed territory as defined in the Commission's energy efficiency policy manual

PG&E shall provideEnergy consumption for each customer class for a given period of time and a given city ·Systemwide residential and nonresidential load shapes and most recent hourly load shapes (usually from the previous year) for a given climate band; Dynamic and static load profiles posted daily at PG&E's website by rate categories; The proportional share in a CCA's territory or proposed territory as defined in the Commission's energy efficiency policy manual

SCE shall provide the number of accounts in each rate group; aggregate consumption for each rate group; Aggregate noncoincident demand in each rate group where metered demand data is available; Coincidence factors which estimate coincident demands where metered data is available; Standard system average load profiles by rate group, to estimate load shapes; The proportional share in a CCA's territory or proposed territory as defined in the Commission's energy efficiency policy manual

The information requirements should not be different for the three major IOUs, and the data made available is inadequate for CCAs seeking to establish load-shaping strategies for renewable resource and energy efficiency development. More information, including a sharing of database fields, customer-specific peak load data, as well as load profiles by rate group, aggregate annual usage data by rate group, energy efficiency program implementation plans, impact forecasts, microgrid congestion, and more specific information should be made available by the IOUs to prospective CCAs. This is clearly an appropriate subject for workshops.

C. SUMMARY

We urge consideration of Implementation Plan-based CRS & look forward to the workshops.

Respectfully,

Paul D. FENN
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CERTIFICATE OF SERVICE

I, the undersigned, hereby declare:

1. I am a citizen of the United States of America over the age of eighteen years. My business address is 4281 Piedmont Avenue, Oakland CA 94611.

2. On January 9, 2004, I caused service of

:

COMMENTS OF LOCAL POWER ON THE PHASE I WORKSHOP ON THE CUSTOMER RESPONSIBILITY SURCHARGE, TARIFFS AND COST-RECOVERY MECHANISMS

to be made by EMAIL upon the parties or their attorneys of record for R.03-10-003.
I declare under penalty of perjury that the foregoing is true and correct. Dated in Oakland, California, this 9th day of January, 2004.

____

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2. Commissioner Wood
3. Commissioner Kennedy
4. Commissioner Brown
5. Commissioner Lynch
6. Administrative Law Judge Malcolm

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