CALIFORNIA COGENERATION COUNCIL
A Combined Heat and PowerAssociation

4391 N. Marsh Elder Ct|Concord|CA|94521

December 9, 2010

Steven Cliff and Sam Wade
Office of Climate Change
California Air Resources Board
1001 "I" Street
P.O. Box 2815
Sacramento, CA 95812

Subject: Comments of the California Cogeneration Council on the ARB Proposed Regulation for a California Cap-and-Trade Program

Dear Steven and Sam,

These comments are offered on behalf of the California Cogeneration Council (CCC)[1] which is an *ad hoc* association of natural gas-fired cogenerators located throughout California. CCC projects serve on-site electrical and thermal loads at industrial, commercial, and institutional facilities across the state and are located in the service territories of California's three major investor-owned electric utilities (IOUs). The CCC represents a significant share of the distributed combined heat and power (CHP or cogeneration) projects now operating in California.

The impact of the "Proposed Regulation to Implement the California Cap and Trade Program" (proposed regulation) on CHP facilities is an issue of significant importance as CCC members evaluate the regulatory landscape of California, and consider their options under the CHP Program Settlement Agreement.[2] These options include whether to continue operations in California and seek new contracts for existing facilities, sign contract amendments adopting an energy payment calculation based on perceived exposure to GHG risk, repower existing facilities, and develop new projects[3]. Investment in upgrading and developing new facilities requires substantial lead time, and as these decisions are being made now, regulatory certainty is essential.

[1] Members of CCC own and operate more than 30 different combined heat and power (CHP) projects in California that collectively generate about 1,300 megawatts (MWs). CCC member projects are "qualifying facilities" (QFs) that sell power to the IOUs under the provisions of the Public Utilities Regulatory Policies Act (PURPA) of 1978.

[2] QF and CHP Program Settlement Agreement filed at the California Public Utilities Commission (CPUC) on October 8, 2010.

[3] The contracts for external power sales referenced in this paragraph should not be confused with CHP contracts for electrical and thermal energy supply for industrial hosts. The majority of the industrial host contracts do not have provisions to accommodate the proposed Cap and Trade program.

There are a number of issues in the proposed regulation and supporting documentation that are of concern to the CCC. It is very difficult to offer a definitive solution for each of these issues because many of them are interrelated or are influenced by other sections of the proposed regulation that have not yet been finalized. The CCC would like to offer these preliminary comments and work with staff on developing the final solutions.

These comments focus on the following areas of concern:

(i) Legacy Contract Issues
   a. No provision for carbon cost pass-through
   b. Transition of CHP ownership
(ii) "Covered Entity" threshold for facilities with indirect emissions
(iii) Equal treatment for electricity suppliers
(iv) Clarify allowance allocation for emissions from CHP associated with electricity sold to the IOUs and/or exported to the grid
(v) Allowance allocation priority
(vi) Lack of detail concerning product-based and energy-use benchmarking
(vii) Process for finalizing the cap and trade regulation

I. Legacy Contract Issues

a. No provision for carbon cost pass-through

The issue of existing contracts for third-party thermal energy supply and electricity supply (collectively referred to as "energy supply") does not appear to have been fully contemplated in the proposed Cap and Trade regulation. Figure J-5[4] indicates that Heat Sold and Electricity Sold will have "Full Carbon Cost Pass-Through", but qualifies these statements by "assuming no existing contract issues". For the CHP sector, this assumption is more likely to be the exception rather than the rule. The majority of CHP contracts were executed with industrial hosts prior to the passage of AB 32 and do not contain provisions for carbon cost pass-through.

Natural gas-fired CHP facilities are inherently energy intensive. CHP facilities that can pass through carbon costs are not trade exposed, but those facilities with existing contracts that do not allow any carbon cost pass-through are arguably more trade exposed than any other industry in California. Unlike other energy intensive trade exposed (EITI) sectors, third-party CHP facilities with existing contracts are not eligible for any allowance allocation. The Cap and Trade program needs to have some mechanism to address this issue. The concern about legacy contracts may be a transition issue. When the commercial agreement between parties expires, any new agreement could include carbon cost recovery provisions.

b. Transition of CHP ownership

Transition of CHP ownership is another issue that will need to be addressed in the solution for third-party energy suppliers with existing contracts. For example, what happens if, at an EITE industrial site, the CHP facility is owned by a third party in 2012, but in 2014 it is purchased by the industrial host? If the industrial host did not emit enough emissions to be a "Covered Entity" or an "Opt-in Facility" in 2012, what happens in 2014 when the industrial host purchases the

[4] See Appendix J of the Initial Statement of Reasons at page J-20.

CHP facility and is suddenly responsible for the GHG emissions compliance costs associated with the CHP facility? Will the ARB provide an allocation of free allowances?

The preferred solution for this issue will likely depend on the solution implemented for allowance allocation for third-party legacy contracts.

II. "Covered Entity" threshold for facilities with indirect emissions

Another issue related to third-party energy supply is the requirement to be a covered entity in order to receive an allowance allocation. Table J-7[5] states that facilities will receive a direct allocation of allowances for thermal energy imported from off-site. But, in order to be eligible for any allocation of allowances, a facility must be a covered entity or an opt-in covered entity. This means the facility must report at least 10,000 metric tons of CO_2e to qualify to opt-in. Consequently, a facility that purchases the majority of its thermal energy from a third-party will have very high indirect emissions, but no direct emissions, and may have an incentive to increase direct emissions in order to become a covered entity and be eligible for an allowance allocation related to off-site thermal supply.

III. Equal Treatment for Electricity Suppliers

Electric distribution utilities as a group will receive an allowance allocation roughly equivalent to 90% of their historical emissions for 2012[6]. Facilities that produce electricity on-site (owned by the industrial entity, as opposed to a third-party facility physically on-site but considered off-site in the proposed regulation) and that qualify for Industry Assistance and are classified as High Leakage Risk will also likely receive a high percentage of their required allowances in a free allocation. All other CHP facilities that supply electricity to industrial hosts will be required to purchase a higher percentage or all of their required allowances. The proposed allowance allocation strategy does not create a level playing field for all electricity suppliers and may provide a disincentive to operate or install CHP. The staff report states that electric distribution facilities will receive free allowances on behalf of California ratepayers and that the utilities will use this allowance value to reduce the costs of AB 32 policies on their ratepayers. Consequently, the potential for a level playing field is slim, unless the auction proceeds used for ratepayer protection are thoughtfully and equitably directed.

The ISOR signals a desire to protect leakage-exposed industrial ratepayers by electric distribution utilities reducing carbon costs faced by industrial sources due to power purchased from the grid. Third-party electricity suppliers to industrial hosts eligible for assistance, should receive allowance allocations comparable to those received by the distribution utilities.

No such protection is envisaged in the proposed regulation for CHP installed at sites not considered a leakage risk. The details of how any compensation will be administered appears to be left up to the CPUC and POU governing boards. How auction proceeds are allocated could distort the market and skew choices away from installing efficient CHP to instead purchase electricity from the grid.

---

[5] See Appendix J of the Initial Statement of Reasons at page J-32.

[6] See Appendix J of the Initial Statement of Reasons at page J-15.

The CCC suggests that treating CHP facilities the same as other deliverers for allocation purposes could result in CHP facilities being economically disadvantaged if their role as a self-provider is not also accounted for. We believe that CHP facilities act essentially as their own retail provider. Consequently, the distribution of auction revenues to retail providers in proportion to the loads they serve without a comparable distribution of auction revenues to CHP facilities would treat CHP inequitably, and that this inequitable treatment would reduce the economic incentives for installing CHP facilities.

The CCC asks the ARB to reconsider the joint recommendation of the CPUC and CEC on this issue. The Joint Commissions in their Decision[7] stated, "We recommend that, for CHP facilities that meet a minimum size requirement, all CHP-generated electricity that is consumed in California, whether delivered to the grid or used on-site, receive allowances on the same basis as other deliverers, and that CHP-generated electricity used onsite receive allowances on the same basis that they are distributed to retail providers."

IV. Clarify allowance allocation for emissions from CHP associated with electricity sold to the IOUs and/or exported to the grid.

In various sections of the ISOR it is implied that the electricity produced by a CHP facility that is sold to an IOU or into the grid, will be governed by the same rules that will apply to independent generators competing in the electricity sector. Specifically, cogenerators will need to purchase allowances at auction for their emissions associated with the exported electricity.

On October 8, 2010, the CHP Program Settlement Agreement was filed at the CPUC and an expedited schedule was adopted with the goal of securing a Commission Decision before the end of 2010.

The new Short Run Avoided Cost (SRAC) energy pricing structure that will be implemented through the settlement, allows that in the event of a GHG cap and trade program in California, the energy price will be subject to a GHG Floor Test as described in §10.2.2 of the Settlement[8]. In this test, the energy price will be the higher of two formulas provided in this section. One of the formulas includes recovery of the GHG Allowance price up to a set heat rate for a specified calendar year. Consequently, it was envisaged in the settlement process that while the market should reflect the cost of allowances purchased by generators at auction, a GHG floor test would be available in the first compliance period to ensure a mechanism to recover the cost of carbon for those qualifying facility (QF) contracts that pre-date the mid-2000s.

After the first compliance period the SRAC energy price will be at "market" and presumably the full cost of allowances will be in the market. While this seems to be a universally accepted notion, it would seem prudent for some mechanism to be put in place to regularly monitor electricity market prices to examine whether the prices permit full recovery of carbon costs for efficient cogeneration facilities.

The ARB appears to suggest in the ISOR, specifically in Figure J-5, that the ARB will **not** provide an allocation of allowances to cover CHP emissions associated with exported power to

[7] CPUC and CEC Joint Recommendation to the Air Resources Board, D.08-10-037 dated October 16, 2008, pg. 250.

[8] See QF and CHP Program Settlement Agreement Term Sheet, pages 47-48.

a utility or to the market. This implication should be made explicit in the cap and trade regulation.

V. Allowance Allocation Priority

§95870 of the proposed regulation prioritizes allowance allocation in the following order:

1. Allowance Price Containment Reserve
2. Advance Auction
3. Allocation to Public Utilities
4. Allocation to Industrial Covered Entities

According to §95870(d)(3), the total number of allowances allocated to industrial covered entities can be reduced in order to ensure that there are sufficient allowances available for the electric distribution utilities. If there are not enough allowances, then what remains will be prorated equally across all eligible covered entities. AB32, however, requires ARB to design measures to minimize leakage to the extent feasible. Consequently, it seems unfair to favor assistance to the public utilities over industrial covered entities. A more equitable approach would be to prorate the remaining allowances between the electric distribution utilities and the industrial entities.

VI. Lack of detail concerning product based and energy-use benchmarking

In reviewing the ISOR it is clear that the development of product based benchmarking and the identification of output metrics to establish benchmarks is at varying stages of development, depending upon the industrial sector. For those industrial entities where CHP is an integrated part of the process and will be subject to product based benchmarking, there is some confusion as to how the energy (both thermal and electric) and associated emissions will be incorporated into the product based and energy use benchmarks. We anticipate that if the proposed regulation is adopted in December, work will continue into 2011 to finalize the benchmarking design. Members operating in specific industrial sectors would like to provide input to that process.

VII. Process for finalizing the proposed cap and trade regulation

We understand from discussions with ARB staff that while the Board may adopt the cap-and-trade regulation at the Board meeting on December 16, 2010, the Board can also delegate authority to the Executive Officer to modify the regulation over the coming year, finalizing the regulation no later than October 2011.

It is our recommendation that work on benchmarking be completed as soon as possible so that affected parties can actually calculate their exposure and accurately forecast budgets for 2012. Affected entities need at least a year to prepare for the new cap-and-trade regime commencing in January of 2012, and the gaps in the current regulation make it difficult to accurately develop budgets and make investment decisions.

Related to the work involved in developing benchmarks, is the issue of clarifying the direct and indirect carbon costs associated with the industrial product, and how allowances are allocated when a third party supplies energy to the industrial entity. As described in these comments, there is a real concern about legacy contracts between industrial hosts and third party CHP.

We look forward to discussing our comments with you in more detail, and to work with ARB staff over the next few months to clarify and refine the cap and trade regulation.

Yours sincerely,

Beth Vaughan
Executive Director