August 11, 2011

Chairman Mary Nichols and Members of the Board
Office of Climate Change
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Treatment of Electricity Use and CHP Generation for Energy Intensive Trade Exposed Entities in Greenhouse Gas Cap-and-Trade Market

Dear Chairman Nichols and Members of the Board:

The Cogeneration Association of California[1] (CAC) offers these comments to address the treatment of combined heat and power generation (CHP or cogeneration) and bundled utility electricity service under the AB 32 cap-and-trade (C-T) regulation. CAC CHP facilities provide thermal and electric energy to refineries and enhanced oil recovery operations, which are considered energy intensive trade exposed (EITE) industries.

These comments offer important refinements to CARB's current draft regulations to eliminate CHP disincentives. In particular, the regulations should be modified to:

- ✓ Include indirect electricity and thermal emissions in the calculation of product benchmarks to avoid distortion and to avoid creating a disincentive to CHP operation and development;
- ✓ Eliminate the disincentive to new CHP generation created under the regulations in the transition from bundled utility service to CHP self-generation;
- ✓ Clarify the use of heat and power adjustment factors in benchmark calculations; and
- ✓ Revise the definition of "cogeneration" to ensure alignment with the existing regulatory framework that permits CHP to deliver energy "over the fence" from the generating site.

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[1] CAC represents the power generation, power marketing and cogeneration operation interests of the following entities: Coalinga Cogeneration Company, Mid-Set Cogeneration Company, Kern River Cogeneration Company, Sycamore Cogeneration Company, Sargent Canyon Cogeneration Company, Salinas River Cogeneration Company, Midway Sunset Cogeneration Company and Watson Cogeneration Company.

Each of these issues is discussed below.

1. Indirect Emissions Should Be Included in Product Benchmark Calculations to Avoid Distorting the Benchmark and Creating Disincentives for Combined Heat and Power Facilities.

Appendix J to the October 28, 2010, Initial Statement of Reasons (ISOR) addresses free allowance allocation to EITE facilities through product benchmarking. Appendix J explains that under product benchmarking, "*the benchmark is a function of the quantity of GHGs released per unit of industrial product output*."[2] While it would be logical to assume that the amount of GHG released per unit of output would include all emissions -- both direct and indirect -- CARB's recent revisions to the regulation suggest otherwise. Appendix B to the July 25, 2011, revised regulation (Revised Regulation) proposes to exclude from the product benchmark calculation indirect emissions associated with "*power purchased.*"[3] The proposal appears to be based on the concern that reflecting indirect emissions would compensate an EITE facility for these emissions through the benchmark. Consequently, if grid power users receive benchmark compensation *and* utility compensation for indirect emissions, they could receive double recovery for the same emissions costs.

CARB's concerns are misplaced. While complications arise from separate treatment of direct and indirect emissions in allowance allocation, these issues do not need to be solved in the benchmark calculation. The primary goal should be first to get an accurate benchmark that reflects all emissions arising from the facility's production. If necessary, depending on the outcome of the CPUC's allocation process, adjustments can then be made to the benchmark award to prevent double recovery. Moreover, the exclusion of indirect grid power emissions from the benchmark calculation would turn the state's goal of supporting CHP operation and development on its head, incentivizing purchased power over the continued operation and development of CHP.

For these reasons, CAC recommends that all emissions, whether direct or indirect, be included in the calculation of a product benchmark. Once the benchmark is established, CARB can then address the potential for duplicative compensation through the adjustment of benchmark allocations.

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2 Appendix J, at J-26.

3 It is not clear whether "power purchased" means only grid power purchased from a utility or also power purchased "over the fence" from a third-party under Public Utilities Code §218(b)(2). Indirect emissions from "over the fence" transactions should be included for the same reasons indirect emissions from grid power are included,

a. *Excluding Indirect Emissions from Grid Power Distorts Product Benchmarks.*

The aim of the product benchmark should be to determine the emissions intensity of producing a unit of output. The true emissions intensity is a function of both direct, on-site emissions and indirect emissions for energy consumed in production. Exclusion of indirect emissions thus leads to a distortion of a facility's and a sector's emissions intensity.

A simplified electricity-related example demonstrates the distortion. Assume that the benchmark is calculated as a weighted average of the emissions intensity of the facilities in the sector, where the numerator is emissions and the denominator is output. Assume further that there are only two facilities – A and B – in the sector. Finally, assume that Facility A and Facility B have the same output and the same electricity use of 60 MW. Facility A self-generates the full 60 MW of output, creating a corresponding amount of direct GHG emissions, while Facility B self-generates 15 MW and uses 45 MW of power purchased from the utility. Under CARB's current proposal, the GHG emissions of 100% of electricity use for Facility A would be included in the benchmark calculation because they would be direct emissions. For Facility B, however, only 25% of the electricity–related emissions would be direct and included in the benchmark. Averaging these electricity emissions in the benchmark numerator is like averaging apples and oranges, distorting the result. The benchmark in these circumstances would reflect emissions for only 37.5 MW of electricity use per facility, while the actual average electricity used to produce each facility's output is 60 MW. The calculated average GHG emissions intensity benchmark would be lower than the true benchmark, i.e., one calculated using 100% of emissions associated with Facility A and Facility B output. As discussed below, this distortion would have a material effect on CHP self-generation.

b. *Excluding Indirect Emissions from Grid Power Creates a Significant Disincentive for Continued Operation or Development of CHP Facilities.*

CARB has expressed clear support for the continued operation of existing and development of new CHP generation. The Scoping Plan estimates that increased reliance on CHP can generate 6.7 $MMTCO_2e$ in emissions reductions. Resolution 10-42 calls for appropriate incentives to increase reliance on CHP:

> *BE IT FURTHER RESOLVED that the Board directs the Executive Officer to review the treatment of combined heat and power facilities in the cap-and-trade program to ensure that appropriate incentives are being provided for increased use of efficient combined heat and power.*

Despite these clear directives, the regulations fail to establish any specific measures to encourage CHP. Moreover, excluding indirect emissions from grid power in the product benchmark calculation will strongly discourage continued operation of existing and development of new CHP.

The example in section a. above can be used to illustrate the CHP disincentive embedded in the benchmarking methodology. As explained above, if indirect emissions are excluded from product benchmark calculations, the effect will be to depress the benchmark to a level that fails to reflect the full scope of electricity GHG emissions resulting from a unit of output. Depressing the benchmark in this way will affect grid purchasers and self-generators differently. A grid power purchaser under this scenario could receive full compensation for its electricity emissions even with a depressed benchmark because its benchmark award will be supplemented with a utility allowance value allocation. A CHP self-generator, in contrast, can look only to its benchmark award to cover its emissions costs. If the benchmark is artificially depressed by the exclusion of certain electricity emissions, a CHP self-generator is highly unlikely to receive sufficient coverage of its electricity-related emissions. The natural effect will be to drive self-generators and their steam hosts toward a combination of boilers and grid power and away from CHP. Not only will this limit efficiency and reliability, it will put additional strain on the electricity supply and transmission system. For this reason, the product benchmark proposal runs contrary to the Scoping Plan and Resolution 10-42, which seek to encourage retention of existing and addition of new CHP facilities.

c. *Recommendation: CARB Should Include Indirect Emissions in the Product Benchmark.*

A variety of solutions could be applied to the problem created for CHP by excluding indirect electricity emissions from the product benchmark. Only one solution, however, would achieve all of CARB's goals: <u>including indirect GHG emissions costs in the product benchmark calculation</u>. Under this approach, the benchmark would most accurately reflect the sector's GHG emissions intensity. The benchmark could then be used to determine allowance allocations to all facilities, regardless of their electricity supply sources. The direct/indirect distinction would arise through an adjustment of the allowance award to reflect compensation received by a facility directly from the electric utility for indirect emissions.

CARB may be tempted to assume that a correct "price signal" for grid power would also solve this problem. This approach, however, would leave EITE grid power users burdened with the full cost of indirect GHG emissions and would run contrary to CARB's objectives of avoiding leakage. By definition, EITE entities cannot recoup GHG costs from their product markets due to the significant potential for leakage. Declining to allocate the allowance value out of the desire to ensure a price signal could also run contrary to the goal of mitigating the AB 32 rate impact on utility customers. Finally, it would do nothing to correct the accuracy of the benchmark as a measure of emissions intensity.

For these reasons, CARB should make clear that all electricity-related emissions – direct emissions, grid power emissions and third-party emissions[4] -- will be included in calculating a product benchmark.

2. Draft C-T Regulations Should Eliminate the Disincentive Created by the Regulations in the Transition from Bundled Utility Service to CHP Self-Generation.

The current regulatory scheme will discourage new CHP, not only by excluding indirect emissions in benchmarking but by failing to address the treatment of allowances when a facility shifts from grid power to self-generation. Assuming the CPUC implements the AB 32 goal of minimizing leakage, an EITE entity purchasing grid power will receive allowance value directly from its distribution utility to offset its GHG compliance costs embedded in electricity rates. If the EITE then decides to invest in additional CHP capacity, it will be responsible for increased direct GHG compliance costs and will lose its share of allowance value from the utility. Not only could it lose the existing allowance value from the utility, it would likely not receive an increase in allowances through benchmarking, since the benchmark[5] award once set will vary only with product output. As a result, the EITE entity's share of allocated allowance value will decrease even though it will face increased direct emission compliance costs. This is antithetical to encouraging new CHP development.

To avoid this CHP disincentive, CARB should require electric utilities to continue providing EITE ratepayers a share of allowance value once they leave utility service. This approach makes sense in light of CARB's approach to allocation of allowances to utilities; if the customer's load was a part of the 2008 usage CARB employed to calculate the 97.7 MMT electric utility allocation, it should take a proportional share of that allocation with it as it leaves the utility system. To reflect this change in the regulations, the following new language should be added to Section 95892(d)(3):

> *<u>Investor owned utilities shall continue to provide an energy-intensive, trade-exposed customer a share of auction proceeds to offset the greenhouse gas compliance costs based on historic usage if the customer leaves the system to be served by combined heat and power.</u>*

Two other approaches could be used. First, designing a product benchmark that both includes indirect emissions and adjusts for direct compensation of grid users by their

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[4] Third-party emissions arise when one facility purchases power from a nearby CHP generating over private distribution wires under Public Utilities Code section 218(b)(2).

[5] Staff has noted that benchmark values will not be recalculated over the course of the C-T program. If indirect emissions are not included in the benchmark calculation and an EITE facility adds self-generation after the benchmark has been established (increasing its direct GHG emissions), the sector benchmark will not adjust to reflect the overall increase in the sector's direct emissions. This penalizes all facilities in the sector and is an additional incentive to include indirect emissions in the benchmark calculation.

utility could mitigate some of the impact. Second, a methodology that provides a CHP adder to the applicable industrial benchmark could provide mitigation. Without a shift of allowances from the utility sector to the relevant EITE industrial sector, however, these approaches would result in short-changing the CHP developer and provide an undue windfall to the electricity sector.

3. CARB Should Clarify the Use of Emissions Values in Assigning CHP Emissions to CHP Thermal and Electric Energy Products.

Appendix B to the Revised Regulation discusses the general methodology employed in developing benchmarks for allowance allocation. It discusses "*Adjustment Factors"* that should be used to account for indirect carbon costs and address carbon cost recovery, identifying adjustment factors for heat and power in Table A:

Table A. Adjustment Factors to Account for Indirect Carbon Costs and Carbon Cost Recovery

Energy Type	Adjustment Factor	Basis	Applied To
Heat	0.0663 metric ton $CO_2e/MMBtu_{heat}$	Assumes that an 80% efficient natural gas boiler sets the carbon cost recovery rate in the market for heat.	Heat sold and heat purchased
Power	0.431 metric ton CO_2e/MWh	Assumes that a 42% efficient natural gas plant sets the carbon cost recovery rate in the power market.[7]	Power sold only[8]

Appendix B explains that *"[i]n the development of the product benchmarks, adjustment factors were used to account for the carbon costs embedded in energy flows as shown in Table A*." Presumably, these factors were used to assign CHP emissions to thermal and electric energy products to adjust emissions in or out of the numerator of a facility's emissions intensity. For example, if a facility that has an onsite CHP plant exports power to a utility or third party, the facility's MRR would be adjusted to remove emissions associated with those exports.

While CARB may have chosen appropriate values to use for each product, it is not clear how the values were used. One approach is to use a residual method. For example, thermal emissions from a facility could be determined residually by taking the CHP facility's total emissions and subtracting electricity emissions, calculated using the power adjustment factor (0.421 MT/MWh). Alternatively, electricity emissions could be determined residually by taking the facility's total emissions and subtracting thermal emissions, calculated using the heat factor (0.0663 MT/MMBtu). The second approach is to use the two adopted factors together to create a proportional assignment of emissions in a manner similar to the California Climate Action Registry (CCAR) methodology. Under this methodology, electricity emissions are determined as follows:

$$E_{TO} – (((O_{TH}/.8)/(O_{TH}/.8+ (O_E/.42)) * E_{TO})$$

Where:

E_{TO} = CHP Facility's Total Emissions
O_{TH} = CHP Thermal Output in MMBtu
O_E = CHP Electrical Output in MMBtu

EPUC recommends that CARB employ the adopted factors using the CCAR methodology, which offers the most moderate results among the options. There may be an inclination as a result of the CHP Settlement to use the power adjustment factor (8125 Btu/kWh or 0.431 MT/MWh) in a thermal residual calculation. CARB should avoid this result for three reasons. First, the heat rate employed in the CHP Settlement of 8125 Btu/kWh was intended to reflect an "avoided" heat rate, not an actual CHP heat rate. Second, the 8125 Btu/kWh factor is relevant under the CHP settlement only through mid-2014; using a factor that has relevance for only 18 months of an 8 year program does not seem balanced. Third, the electric residual method using 8125 Btu/kWh can result in distorted thermal efficiencies. For example, assuming a CHP with a simple cycle heat rate of 11,600 Btu/kWh and a 1.5 heat to power ratio, the residual electric method at 8125 Btu/kWh would allocate only 30% of the total emissions to steam. This compares with a thermal allocation of 49% under the 80% boiler residual method, 41% under the traditional CCAR method (using a 42% efficiency) and 60% under the CPUC's output method.

For these reasons, EPUC recommends employing the adopted heat and power adjustment factors in the CCAR methodology for purposes of splitting thermal and electric emissions from a CHP facility.

4. The Cogeneration Definition Must Be Revised to Ensure Alignment With Existing Regulatory Framework

The revised regulation modifies the definition of "cogeneration." The revision creates an ambiguity in the definition and fails to ensure alignment with the current California regulatory framework that defines and governs cogeneration.

The Revised Regulation defines cogeneration in a manner that requires "onsite generation":

> *(47) "Cogeneration" means an integrated system that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy. Cogeneration must involve* ***onsite*** *generation*

of electricity and useful thermal energy and some form of waste heat recovery.

The use of the term "onsite," which is not defined in the regulation, creates an ambiguity. The ambiguity arises from the fact that some facilities use cogeneration thermal or electric energy that is not produced onsite, but delivered "over the fence", on the site of another entity. Public Utilities Code (PUC) Section 218 permits "over-the-fence" transactions when electricity is delivered by the generator for:

(1) Its own use or the use of its tenants.
(2) The use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated or on real property immediately adjacent thereto ….,

The use of the term "onsite" in the current cogeneration definition could be interpreted to exclude these over-the-fence transactions that are currently permitted. To eliminate any ambiguity that could adversely impact the current regulatory framework governing cogeneration, the following modification should be incorporated in the regulation's definition of cogeneration:

(47) "Cogeneration" means …. energy. Cogeneration must involve ~~onsite~~ the generation of electricity and useful thermal energy and some form of waste heat recovery.

CAC appreciates your consideration of these recommendations. Please contact us with any questions.

Very truly yours,

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