BEFORE THE CALIFORNIA ENERGY COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of: Preparation of the 2012 Integrated Energy Policy Report (2012 IEPR)	Docket No. 12-IEP-1D

COMMENTS OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION IN RESPONSE TO REQUEST FOR COMMENTS ON THE TECHNICAL AND MARKET POTENTIAL FOR NEW CHP IN CALIFORNIA

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In response to the Assigned Commissioner's ruling of February 2, 2012, the California Large Energy Consumers Association (CLECA) provides these comments on the ICF Report on technical and market potential of combined heat and power (CHP) and related questions from the agenda for the February 16, 2012 Workshop, set forth below. CLECA does not respond to all of the questions listed.

The Energy Commission seeks to "*determine where the opportunities for development of new [CHP] facilities are greatest*" in order to "*develop policies and regulations to encourage CHP and support the state's GHG emissions reductions goals*".[1] CLECA strongly supports this goal. We caution, however, that the flawed assumptions in the ICF Report will impede an accurate determination of CHP potential. We provide some details on these assumptions below. We also make recommendations for policy changes that could facilitate the development of new CHP or, at a minimum, eliminate current disincentives for new CHP.

I. ICF Report on technical and market potential of CHP including scenario analysis

1) Are there major flaws in the assumptions or errors in the report that would have a significant influence on the findings?

Yes, there is one glaring omission and there are several major flaws in the assumptions used in the analysis.

The glaring omission is the complete neglect of bottoming cycle CHP in the analysis. It is not even included in the schematic of CHP provided in

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1 Notice for Lead Commissioner Workshop on Combined Heat and Power in California, at 2.

the report. (See, for example, p. 13 and p. 37 which focus entirely on topping cycle.)

The flawed assumptions include the following:

1. The forecasts of the price of natural gas as boiler fuel, delivered, on page 66 are much too high; for the 2011 to 2015 period, the report forecasts a range from $5.60/MMBtu to $8.23/MMBtu.[2] Current gas price forecasts are much lower, as reflected in various parties' testimony served in the ongoing Southern California Edison Company (SCE) Phase 2 general rate case proceeding.[3] The three-year average forecast price for natural gas, delivered, for the electric sector for 2012-2014 should be closer to $4.32/MMBtu. Furthermore, it is very likely that gas transportation costs will increase due to the safety review for gas pipelines,[4] although we understand that the consultants do not have an estimate of the associated rate increase at this time.

2. The assumption on page 76 that the transmission and distribution part of rates should be fixed in real terms for the rest of the forecast period is totally unfounded. Major transmission additions are being made to bring renewable generation to load centers,[5] and these additions have their costs front-end loaded through the use of Construction Work In Progress at FERC. SCE has a pending Phase 1 general rate case in which the utility is asking for major increases in rates to replace what it characterizes as aging distribution infrastructure.[6] San Diego Gas & Electric Company (SDG&E) also has a pending Phase 1 general rate case with distribution-related increases, and Pacific Gas & Electric Company (PG&E) will file a

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2 ICF Consultant Report: Combined Heat and Power: Policy Analysis and 2011-203 Market Assessment (Feb. 2012), at 66. This leads to similarly inaccurate forecasts of CHP fuel prices on the same page.

3 *See, e.g.*, Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association, served February 6, 2012 in A.11-06-007, at 41 (recommending an average 2012-2014 gas price of $4.28/MMBtu); *see also* Testimony of Dr. Barbara R. Barkovich and Catherine E. Yap on Marginal Costs, Revenue Allocation and Rate Design on Behalf of The California Large Energy Consumers Association and The California Manufacturers and Technology Association, served February 6, 2012 in A.11-06-007, at 20 (recommending a $4.40/MMBtu gas price); *see also* Prepared Direct Testimony of James A. Ross on behalf of the Energy Producers and Users Coalition, served February 6, 2012 in A.11-06-007, at 25 (recommending an average 20120-2014 gas price of $4.47/MMBtu).

4 *See, e.g.,* California Public Utilities Commission Rulemaking 11-02-019.

5 The new transmission currently planned to meet the 33% RPS is estimated to cost approximately $7.1 billion. The planned new transmission lines are in various stages of permitting and/or construction; they include: the Sunrise Power Link; Tehachapi Transmission Project; Colorado River-Valley; Eldorado-Ivanpah, the Carrizo-Midway reconductoring; the Boden-Gregg reconductoring; Pisgah-Lugo; West of Devers reconductoring; Coolwater-Lugo; and Mirage-Devers. *See* California Energy Markets, Feb. 10, 2012, at 14-15.

6 *See, e.g.,* California Public Utilities Commission Application 10-11-015 (SCE's 2012 GRC Phase I, seeking a 2012 base distribution revenue requirement increase of $597 million).

test year 2014 Phase 1 general rate case in late 2012, which is sure to include distribution-related increases. The proposed distribution-related revenue requirement increases are well in excess of inflation.

3. The discussion of what generation-related costs can be avoided through CHP is at best confused. While the marginal cost of generation may be based on a natural gas-fired power plant, the changes in generation revenue requirement will be a function of the size and mix of generation resources used to serve load. These generation-related revenue requirement increases, which will be reflected in the generation component of rates, will in significant part be driven by the cost of new renewable generation to meet the 33% RPS goal. The CPUC has reported that new renewable generation is being procured at significant cost and this will result in greater increases in the generation revenue requirement, and thus greater increases in generation-related rates, than those forecast by ICF.[7]

Since the electric revenue requirement for generation, transmission, and distribution is likely to see substantial increases for the reasons stated above, the increase in electric rates that can be avoided through on-site use of CHP is likely to be significantly greater than that shown in Table 20.

4. The statement on page 86 that SCE and SDG&E rates are low currently for larger customers compared to 2009 may be true, but again, it ignores the fact that both utilities have Phase 1 general rate cases pending as well as Phase 2 cost allocation cases pending.[8] Both will increase utility revenue requirements and both have the potential to increase larger customer rates regardless of revenue requirement increases.

5. The report refers to an avoided transmission and distribution (T&D) cost for CHP of $50/kW-year. However, there is no explanation of the source of this figure. While CHP has the ability to avoid or defer T&D costs, this is likely to be location-specific. An assumption of a blanket avoided T&D cost is thus questionable.

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[7] *See* Renewables Portfolio Standard Quarterly Report 4th Quarter 2011 (available online at: http://www.cpuc.ca.gov/NR/rdonlyres/3B3FE98B-D833-428A-B606-47C9B64B7A89/0/Q4RPSReporttotheLegislatureFINAL3.pdf). In 2009, when the RPS contract costs averaged around 10¢ per kWh, the projected costs of a 33% RPS, incremental to the 20% RPS, ranged from an additional $1.9 billion to an additional $7.4 billion. *See generally* 33% Renewables Portfolio Standard Implementation Analysis Preliminary Results (June 2009) (available online at: http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf).

[8] *See, e.g.,* California Public Utilities Commission Application 10-11-015 (SCE's 2012 GRC Phase I, seeking a cumulative base revenue requirement increase of ~$1.845 billion); *see also* California Public Utilities Commission Application 11-06-007 (SCE's 2012 GRC Phase 2, seeking significant rate increases for large power customers).

2) Using the various scenarios as a guide for outcomes of regulatory changes, what regulatory changes should the state pursue and why?

A review of departing load charges should be undertaken across all utilities to determine whether these are still justifiable for customer-side generation. In addition, a review of standby charges in each utility's general rate case Phase 2 is also appropriate to determine if these standby charges appropriately recover the cost imposed on the system by the on-site generation and reflect the diversity of backup generation requirements. It is useful to note that smaller customers with renewable on-site generation can avoid many costs through net energy metering that CHP customers cannot avoid.

We note that bottoming cycle CHP, which uses waste heat to generate electricity, is essentially pure energy efficiency (EE). Just as customer load reductions resulting from increases in EE do not trigger departing load charges, customer load reductions due to use of on-site bottoming cycle CHP should likewise not trigger departing load charges. To the extent that bottoming-cycle CHP is assisted by some supplemental natural gas firing, as long as this supplemental firing results in an electrical efficiency greater than a new combined cycle plant and has less GHG emissions, which can be demonstrated through engineering calculations, that supplemental firing should not automatically trigger departing load charges either.

It is also important to note that there are trade-offs between traditional EE investments and production of electricity from waste heat. All industrial facilities with high temperature processes use the waste heat to reduce overall energy usage, e.g. by recirculating the waste heat in order to preheat process streams. However, the more the waste heat is used for such purposes, the less heating value there is for electricity generation. Furthermore, the optimal mix of uses for the waste heat recovered is likely to vary by facility. Any state EE policies should take this trade-off into account.

Furthermore, the state should address the fact that new on-site CHP will be disadvantaged by the inability of customers to receive GHG allowances or allowance revenue to cover their increased emissions under the CARB decision to provide free allowances for the benefit of electricity consumers, unless customers with new CHP can take their share of the allowances with them. We have addressed this matter in comments before the CPUC, which are excerpted below.

"State policy expressly and repeatedly has recognized the value of CHP resources. CHP nonetheless faces a number of barriers in California, not the least of which is the significant nonbypassable charges carried by a customer investing its own CHP capital. ARB has expressed its intent that the C-T program not further burden CHP, and that it actually provide incentives to CHP investment. This Commission, in coordination with ARB, must carry out this intent by examining potential CHP disincentives and designing an express solution.

California policy expresses clear support for the continued operation of existing and development of new CHP generation.

• ARB's Scoping Plan estimates that reliance on CHP could generate 6.7 $MMTCO_2e$ in emissions reductions.

• The Governor's Clean Energy Jobs Plan calls for the addition of 6,500 MW of new CHP by 2030.

• Executive Order S-3-05 requires an 80% reduction in emissions when compared to 1990 levels by 2050.

Resolution 10-42, adopted by its Board in December 2010, goes one step further by calling 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.

Perhaps most importantly from this Commission's perspective, D.10-12-035 approves a CHP program aimed in part at encouraging installation of additional CHP capacity.

Despite these very strong policy signals to CHP, the cap-and-trade (C-T) program will create disincentives to CHP investment absent an express design choice by this Commission. An energy-intensive, trade-exposed (EITE) or non-EITE consumer investing its own capital in CHP will materially change its emissions profile. Its indirect emissions will decline, commensurate with its reduction in grid electricity purchases, and its direct emissions will increase, commensurate with its self-generation of electricity. These increased direct emissions increase the facility's C-T compliance obligation, if it has such an obligation, requiring the consumer to surrender allowances to cover them. While its direct compliance obligation and costs will increase, its overall emissions cost coverage as an EITE or non-EITE will decline. The current ARB EITE benchmarking methodology, however, will not provide this EITE facility additional free allowances when it leaves the grid, absent a change in output. Moreover, unless this Commission provides otherwise, the EITE facility could also lose its share of utility auction revenues when it discontinues utility service. The net effect would be to fully expose the EITE facility to the added direct emissions cost. Under these circumstances – exacerbated by other CHP barriers -- it is unlikely that an entity would make the business decision to install CHP unless the risks of increased compliance obligation are mitigated.

Solutions are available to address this issue. The correct solution, however, will depend on which EITE methodology the Commission elects as explained further in Section III.

In mitigating the potential underinvestment in CHP, these solutions address another objective raised in the Ruling: they will maintain competitive neutrality across load-serving entities. CHP can be seen as a competitive alternative to utility or electric service provider services. Thus, to maintain competitive neutrality, the Commission needs to ensure that when a consumer chooses an alternative to utility service, it is not disadvantaged." (R. 11-03-12, "Large User Proposal for Allocation of Utility Allowance Value under Cap-and-Trade, October 5, 2011, pp. 18-21).

3) Is use of the Scoping Plan's GHG reduction accounting method appropriate? If not, provide an alternative.

Not addressed.

II. Small and Large CHP project development in California

1) What impact will Cap and Trade have on development of non-utility owned CHP? Would having a utility contract change the likelihood of development? How large a factor is the uncertainty of Cap and Trade prices in the decision to install a CHP unit?

Our previous response explains how the implementation of Cap and Trade and the allocation of the revenue from the sale of free allowances granted to utilities on behalf of their customers will have a negative impact on new CHP unless customers can take their allowance value with them when they develop on-site CHP. They will have increased allowance requirements if they use natural gas in the CHP and will lose the allowance value provided by the utility unless that allowance value is portable. This problem can be overcome if customers are given the full value of the free allowances granted to the utilities on their behalf (i.e. part or all of this value is not siphoned off for increasing already-substantial energy efficiency or similar programs) and these customers can take this allowance value with them if they adopt CHP. This requires action on the part of the CPUC as well as CARB.

Having a utility contract is not the primary consideration for all non-utility owned CHP. For CHP that produces less electricity than needed on site, (*e.g*. bottoming-cycle CHP,) to our knowledge customers generally intend to use the output on-site to avoid buying electricity from the utility or another LSE. (We note, as an aside, that utility-owned CHP is not the model in California.)

2) Net-metering for CHP is restricted to fuel-cells and projects that use biogas. Under these parameters have there been any net-metered CHP projects and what are they? Should net-metering be expanded to apply to additional CHP technologies? If so, up to what capacity? Explain.

There has been extreme political resistance to allowing net energy metering (NEM) for any technologies other than renewables, fuel cells, and biogas or for applications greater than 1 MW. Thus, NEM has resulted in preferential treatment for these technologies and project sizes. Since NEM allows for the avoidance of T&D costs by the customer that are not in fact avoided by the on-site generation, this results in cross-subsidies by other customers, including those with CHP, of the NEM customers. This creates an actual disadvantage for CHP. While we believe that allowing NEM for CHP is a political non-starter, eliminating or reducing the current subsidy of NEM customers would help eliminate an inequity. We also note that NEM allows a customer to avoid some of the nonbypassable charges that other customers with on-site generation must pay. In the case of the former Public Goods Charge, this charge was not supposed to be bypassable through NEM, but it was; the replacement Energy Procurement Investment Charge and Procurement Energy Efficiency charge will likely also be bypassable for NEM customers.

3) A key feature of AB 1613 is that it allows for export and payment of excess electricity. Will the availability of an AB 1613 feed-in tariff effect your decision to pursue a CHP project in California? Are there any deficiencies in the current implementation of AB 1613? How should they be changed?

We note that the utilities have strongly resisted payment for excess electricity for any source, as opposed to a defined quantity under contract. We are aware of the situation where a customer can have excess generation, *e.g*., if the customer has on-site renewable generation and its business operations are down for maintenance. Interconnection requirements have inhibited the ability of customers to provide such generation to the grid, especially for projects over 1 MW. There could be a similar situation with CHP, although it would not likely apply to bottoming cycle CHP, since the waste heat used to generate electricity is a central part of the manufacturing process and the CHP output is only a fraction of the total load of the customer.

For CHP Developers and Project Owners

Not addressed

III. Technology Innovation to Overcome CHP Barriers

Not addressed

IV. QF Settlement and Infrastructure Planning
Questions for CPUC

Not addressed

Questions for the Investor-owned Utilities

Not addressed

Questions for CHP Representatives

The standard planning assumptions in the 2010 LTPP included continued operation of existing CHP, and 1,872 MW of new CHP (1,522 MW in the IOU service territories) that operates at very high capacity factor and evenly divides its output between on site use and export.

1) Are existing QF resources that meet the double benchmark likely to be more or less competitive than new projects in CHP RFOs?

Not addressed

2) Is it reasonable to expect that existing resources that fail to meet the double benchmark will continue to operate without a PPA?

Not addressed

3) What conditions are/might be necessary to realize this quantity of new CHP? What is the likely impact of failing to get a long-term contract for exports on development?

Elimination or significant reduction of departing load charges, with no potential for later increases, and a workable, timely interconnection process are necessary. The impact of a long-term contract for exports would depend on the size of the CHP and the size of the onsite load.

4) If large quantities of new CHP are developed, is the assumption of a 50/50 *split between on-site use and export a reasonable one? If not, what might a more reasonable split be?*

The split between on-site use and export depends on the nature and amount of the process heat or steam load in the case of topping cycle CHP, which is a function of the type of facility. As stated earlier, for bottoming cycle CHP, the use is most likely to be on-site.

Questions for All

1) *What is a reasonable planning assumption (single point or range) for the peak capacity value of CHP development during 2013 – 2022?*

Not addressed

IV. General Questions for All

1) What additional analysis can complement the work completed to support changing CHP development regulations and goals? (i.e. GHG emissions comparison to displaced technologies, etc.)

Not addressed

2) Should the state create incentives or penalties to ensure achievement of targets? If so, please suggest program design and implementation.

Not addressed

3) What are the near-term and long-term actions needed to achieve 6,500 MW by 2030?

Near term actions are recognition of bottoming cycle CHP, elimination of departing load charges, and reformation of the interconnection process. In addition, the disincentives created under Cap and Trade for new CHP should be eliminated as discussed above.

4) What additional steps could the state take to encourage further development? Prioritize and explain.

Not addressed

5) What market opportunities exist for bio-powered CHP?

Not addressed

6) What challenges limit the penetration of bio-powered CHP at existing facilities, such as waste water treatment plants or food processing facilities?

Not addressed

7) What can the Energy Commission, or the state, do to increase market penetration of bio-powered CHP?

Not addressed

8) What can be done from, a regulatory standpoint, to reduce uncertainty for CHP development?

Eliminate the departing load charges; their rate of growth is uncertain and the imposition of these high charges inhibits the investment of private capital in CHP. In addition, clear and timely resolution of the disincentives for new CHP under Cap and Trade is important, since the fact that this matter has not been addressed by CARB is hindering new CHP.

9) What is the potential development of CHP that could be classified as renewable? What are the major regulatory barriers to renewable CHP development and how can they be addressed?

Not addressed

10) AB 1613 also encourages utilities to take advantage of CHP. Will utilities take advantage of this opportunity? If not, why? What would it take?

Not addressed

11) Utilities have had a role in CHP development in the past. Is there a role for CHP in the utility portfolio and what role would it play? What interest do utilities have in developing of CHP? What incentives are necessary?

Not addressed

Respectfully submitted,

/S/

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