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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 ENERGY PRODUCERS AND USERS COALITION AND THE COGENERATION ASSOCIATION OF CALIFORNIA ON COMBINED HEAT AND POWER

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March 9, 2012

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The Energy Producers and Users Coalition[1] and the Cogeneration Association of California (CHP Parties) [2] provide these comments on the *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*, prepared by ICF International (ICF Report), and the questions posed by the Commission during the workshop held on February 16, 2012.

INTRODUCTION

California's policy for promoting combined heat and power (CHP) resources is ripe for reconsideration. Many "kind words" have been offered for CHP over the years, expressing support for the continued operation and development of these resources. To advance CHP development beyond the existing fleet, however, will require clear and decisive policy changes. These policy changes must be based on a broad examination of CHP benefits and account for a variety of CHP characteristics. These comments outline the needed changes.

California's general support for CHP resources has been voiced repeatedly in high level policy statements:

- Section 372(a) of the California Public Utilities Code states: "*it is the policy of the state to encourage and support the development of cogeneration technology as an efficient, environmentally beneficial, competitive energy*

[1] EPUC is an ad hoc group representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, BP West Coast Products LLC, Chevron U.S.A. Inc., ConocoPhillips Company, Shell Oil Products US, THUMS Long Beach Company, and Occidental Elk Hills, Inc.

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

resource that will enhance the reliability of local generation supply, and promote local business growth."

- The CPUC recently found in D.10-12-035: "*Public Utilities Code Section 372(a) and Energy Action Plan II both demonstrate that state policy supports the development of "efficient, environmentally beneficial" CHP. In the 2009 Integrated Energy Policy Report (IEPR), the CEC recommended the continued support and development of CHP as a means to meet state greenhouse gas (GHG) goals and other policy objectives. In D.08-10-037 the Commission, joining with the CEC, recognized CHP as an emissions reduction strategy, provided for action to remove barriers to CHP penetration, and acknowledged the need for CHP policy review*." [3]

- The California Air Resources Board (CARB) stated in its Scoping Plan that: "*Combined heat and power (CHP), also referred to as cogeneration, produces electricity and useful thermal energy in an integrated system. The widespread development of efficient CHP systems would help displace the need to develop new, or expand existing, power plants*."[4]

- CARB also committed to promote CHP in Resolution 10-42 which "*directs the Executive Officer . . . to ensure that appropriate incentives are provided for increased use of efficient combined heat and power;"* [5]

Consistent with these views, the CPUC has recently adopted and implemented the CHP Program Settlement in D.10-12-035. While all of these indications of support are positive, neither policy statements nor the CHP Settlement can breathe life into CHP development without further action. Indeed, as the CHP Parties have observed, the CHP Settlement is only a bridge to a long-term CHP policy – it should not be viewed as a pier. The CHP Parties thus strongly support this Commission's initiative to reexamine the state's CHP policy.

In designing a more robust policy, the Commission should broadly consider CHP benefits. The ICF Report states that *"[t]he contribution of CHP to statewide reductions in greenhouse gas emissions is the principal motivation for this market assessment and identification of policy measures that will increase CHP market penetration*." [6] While focus on GHG benefits has been keen since the passage of AB 32, the Commission should not lose sight of the other benefits of CHP generation:

- Increased efficiency of fuel used in generating electricity through the simultaneous production of electric and thermal energy;

- Increased grid reliability and voltage support results from the distribution of CHP resources across the statewide electricity grid;

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3 D.10-12-035 at 7.
4 Scoping Plan Document at 44.
5 CARB Resolution 10-42 at 11.
6 ICF Report, at 7.

- Greater business certainty and operational reliability, as well as the potential to manage and stabilize energy costs, accrue to California's commercial and industrial consumers;
- Transmission and distribution losses can decrease as customers self-serve their own load and when CHP locates in key load centers; and
- Deferral or avoidance of significant new transmission infrastructure.
- Diversity of ownership and geographic dispersion of resources at California business sites with supply that is committed to serve load within the state.
- Private in-state investment, increasing the industrial tax base, and providing high paying manufacturing jobs.

In short, the Commission's analysis thus should not stop with quantifying GHG benefits.

The Commission's analysis also should assess benefits of CHP and barriers to development taking into account the varied characteristics of these resources. California's fleet of CHP resources, as the ICF Report recognizes, will never be homogenous. The ICF Report analyzes a range of sectors, including industrial, commercial, institutional, and multifamily residential applications. The report further segments these applications by size, load factor, on-site versus off-site and other criteria. Given this diversity, drawing uniform conclusions risks distorting findings or recommendations in favor of one type of CHP resource over another. For example, the system benefits of several small commercial installations may not yield the same environmental benefits as the installation of a larger industrial CHP facility. Likewise, the structure of standby rates may be a deterrent to certain small project developers but not to larger CHP projects. Finally, power sales opportunities may be very important to a thermally matched resource whose electric generation exceeds its on-site electrical requirements, but not to a resource that is electrically matched and stays "behind the meter." California thus must be cautious in reaching for a "one size fits all" conclusion or solution.

With this concern in mind, these comments examine the ICF Report primarily from the standpoint of CHP development undertaken by large industrial customers, such as refiners and oil producers. In addition, they offer limited observations regarding the AB 1613 program. These comments thus propose solutions for the large-scale industrial CHP sector, nearly all of which have relevance for smaller applications. In particular, the California policy makers should:

- Provide secure, long-term opportunities to sell excess power into the market at compensatory prices with commercially reasonable contract terms and conditions;

- Eliminate departing load charges imposed on customer load served by CHP generation;
- Eliminate potential carbon-related disincentives to CHP development in implementing the AB 32 cap-and-trade (C-T) program;
- Permit CHP facilities to “self-wheel” over the grid to provide electricity to other commonly owned or affiliated operations;
- Reform scheduling requirements for resources with limited exports and highly variable thermal and/or electric loads behind the meter;
- Prevent utility interference with the installation of new facilities behind existing PPAs, by permitting a customer to determine which on-site generation will be used to serve its load; and
- Ensure that once installed, a customer may fully use its CHP output regardless of the on-site metering configuration.

The CHP Parties urge the Commission to move forward with this initiative, coordinating with the CPUC, CARB and other state agencies, to advance these changes in CHP policy.

RESPONSES TO COMMISSION REQUEST FOR COMMENTS

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?

Without having access to the ICF models, it is difficult to know precisely how or to what degree a particular assumption could have a “significant” influence on its findings. The CHP Parties thus simply identify assumptions that differ from their own development and operation experience without drawing clear conclusions. The CHP Parties have identified issues for further consideration in refining the ICF assumptions:

(1) The ICF Report assumes that “high load factor” customers operate 7,500 hours a year, or an 85% capacity factor;[7] many if not most of the EPUC facilities operate under base load conditions closer to a 95% capacity factor.

(2) The ICF Report does not appear on the surface to account for the age of existing heat production facilities. While an oil field, for example, may appear to have technical or even economically viable potential for additional CHP, that potential is illusory in cases where the field has recently installed new boilers with 20-30 year lives. In short, the report does not address CHP opportunities recently lost as a result of regulatory delay and uncertainty. While the CHP Parties do not have sufficient data to fully evaluate the impact

[7] ICF Report, at 41.

on boiler life on oil field potential, recent boiler acquisitions suggest that the actual development potential in this sector is lower than identified.

(3) While the natural gas price forecast is based on recent EIA data, it trends somewhat higher than forecasts being used for other purposes in the California regulatory environment.[8]

(4) The "net power cost" for large installations – 4.7 cents/kWh -- appears significantly understated. First, the capital investment assumptions of $1,254 per installed kW for a 40 MW CHP facility is less than the small gas-turbine simple-cycle technology of $1,292 per installed kW (2009 nominal $) presented in Table 2 on page 2 of the Commission's report CEC-200-2009-017-SF. This is significant because simple-cycle installations do not have the additional equipment cost associated with the CHP thermal production. Moreover, the fixed cost portion of the "net power cost" is based on an annual levelized cost of about $147/kW-year. The simple-cycle levelized cost in the Commission's report is on the order of $323/kW-year which is more than twice that of the CHP facility. Thus, the fixed carrying charge calculation also appears to be dramatically understated. Furthermore, larger CHP installations may be based on installing larger turbines, such as the nominal 85 MW GE 7EA gas-turbine which have different cost and operating characteristics than the smaller 40 MW gas-turbines. In addition, the net power cost excludes many of the costs actually incurred in the development of a CHP plant (e.g., construction, land, etc.). Finally, the assessment does not take into account that large CHP facilities encounter significant capital investments that are project specific and can greatly impact the overall costs to a project. Taking all of these factors into account, the actual installed costs for large CHP projects range from $1900 to $3000 per installed kW. Additionally, the annual levelized fixed carrying charge for these projects would range from 18% to 25% of the capital investment.

The CHP Parties observe that, on balance, the ICF Report appears to overstate the economic viability of large-scale CHP based on project analysis undertaken by the CHP Parties over the past several years.

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8 *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).

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

If California hopes to come close to achieving the goals in the CARB Scoping Plan or the Governor's platform, the ICF scenarios show that very material policy changes are required. The CHP Parties submit that, to meaningfully advance CHP operation and development, California should:

- ✓ ***Provide secure, long-term opportunities to sell excess power into the market at compensatory prices with commercially reasonable contract terms and conditions;***

If California seeks to encourage highly efficient, thermally matched CHP, the natural result will be excess energy and capacity that must find a home on the grid. An opportunity to take the daily market price, which will be highly variable and will depend on which resource is on the margin at a particular time, does not provide sufficient security to make a thermally matched CHP investment. Making available secure, long-term contracts for existing and new resources is a critical step in policy advancement.

- ✓ ***Eliminate departing load charges.***

Current departing load charges, which must be paid by a customer serving its own load, range from $13.72 per MWh (SCE TOU-8-Sub) to $22.22 per MWh (PG&E AG-5 customers). The customer must pay these charges on top of all other generation costs incurred directly in installing and operating the CHP – costs that include capital, fuel, operations and maintenance, emissions reduction credits, overhead and the cost of debt and/or any hoped-for return on the capital invested.

CGDL costs vary with usage, making them a variable cost in assessing decisions to self-generate. Assuming an attributed electric heat rate of 8,125 Btu/kWh, a gas price of $4.00, and an O&M cost of $2.50, the variable cost of generating would be roughly $35.00 per MWh. This means that on the SCE system, a TOU-8 subtransmission customer's CGDL charges of $13.72 per MWh would increase the typical variable cost of generating by nearly 40%. At the high end, for an agricultural customer on the PG&E system, these charges would increase the variable operating cost by 60%.

Examined from another perspective, CGDL charges have a strong influence on customers evaluating CHP as an alternative to the use of a boiler and purchase of grid power. To finance a CHP facility, a customer must either take on debt or employ internal capital, and many of these potential projects compete globally with other projects for internal capital. -Adding departing load charges effectively acts as a barrier by increasing the hurdle rate for project economics. For example, consider a customer generation project that has an installed cost on the order of $1,000,000/MW and an 11% internal rate of return. A project with an initial 11% hurdle rate (a rate slightly lower than a utility rate of return on equity) would require a total return on investment of nearly 23% to compensate for the entire $13.72/MWh of departing load charges assessed to a TOU-8 sub-transmission customer in order to justify development. In other words, the departing load charges materially and directly increase the cost of investment in CHP above the cost that would be faced by a utility installing the same facility.

The Commission should work together with the CPUC to avoid continued application of these charges to load served by CHP resources.

- ✓ ***Eliminate potential carbon-related disincentives to CHP development in CARB's cap-and-trade (C-T) program.***

As discussed further below, the C-T program, all other things held equal, will detrimentally impact the development of non-utility-owned CHP. When a customer leaves the grid to self-serve its load using CHP generation, its direct carbon compliance obligation will increase. Moreover, its total carbon cost may increase as a result of installing CHP, depending on the outcome of the CPUC and CARB resolution of these issues. These agencies should coordinate to remove any potential disincentive.

- ✓ ***Permit self-wheeling by a CHP facility to provide electricity to other commonly owned or affiliated operations.***

Today, a CHP generator that has excess power is for all practical purposes limited to selling the power in the wholesale market. Certain CHP generators, however, may have better economic options if permitted under state law to wheel their power to other commonly owned or affiliated operations in the state. Permitting self-wheeling would enhance the attractiveness of installing CHP.

- ✓ ***Reform scheduling requirements for resources with limited exports and highly variable thermal and/or electric loads behind the meter.***

The former CHP program under the Public Utility Regulatory Policies Act of 1978 (PURPA) did not obligate a CHP and its host to render a binding schedule for grid deliveries. The thermal host was in a position to operate its industrial operation without coordinating plant operations with grid export forecasts. Today, the CAISO maintains strict scheduling requirements, forcing CHP hosts to schedule their power exports for every 15-minute interval. Deviating from this schedule can result in economic consequences and ultimately could result in penalties. Creating a program similar to the Participating Intermittent Resource Program (PIRP) administered by the CAISO for renewable resources, which gives these resources greater flexibility in matching schedules to actual delivers, could ease this strain.

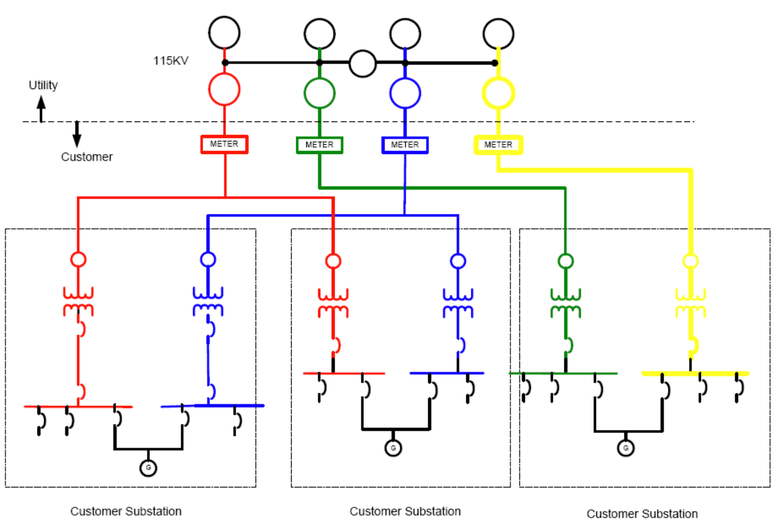
✓ ***Prevent utility interference with the installation of new facilities behind existing PPAs.***

Utilities have complicated and deterred customer plans to install new generation behind points of interconnection with an existing PPA. They argue that placing new generation behind an existing PPA could effectively increase deliveries under that PPA. They are concerned that if the new generation were sequenced first to self-serve load, reducing the existing generation needed for this purpose, exports under the existing PPA could increase. They have thus suggested that the customer should be forced either to give up its existing PPA or interconnect its new project at another point of connection.

California could eliminate a barrier to CHP development, particularly small resource development, by clarifying this issue. California policy should make clear that a customer can install new generation behind an existing PPA without having to sacrifice the existing contract. Specifically, the customer, at its election, should be permitted to sequence the new generation first to serve load.

✓ ***Ensure that once installed, a customer may fully use its CHP output regardless of the site boundary metering configuration.***

Using the output of a customer-owned CHP facility is straightforward in most circumstances, allowing the utility to measure exports or imports on a net basis at a single site-boundary meter. In some cases, however, CHP configuration may differ as a result of historical configurations or the cost-effectiveness of interconnection solutions. Consider, for example, a large industrial facility with four lines between load and generation and the point of interconnection. Two of the lines may have net generation, while the remaining two may have net load. The following schematic depicts this problem:



In the diagram above, there is no single site-boundary meter. Instead, the four lines serving the facility, which may have net load or generation, are separately metered by the utility using four separate meters in the same location. The meters are within a few feet, as depicted below.

It would seem logical for the utility to net the four meters to determine a net import or export from the industrial site. Instead, however, a utility has taken the position that any such netting would represent "retail wheeling" and has refused to net the meters. As a result, the customer must export generation that it could be using on site, while being forced to simultaneously purchase electricity from the utility in an amount roughly equal to the exported generation. California policy should provide that, regardless of the metering configuration, a utility should permit the customer to net all load and generation at a single site.

Each of these seven recommendations will move the state's CHP policy forward. Critically, to give these changes sufficient regulatory certainty to induce new investment, ***key elements of the state's CHP policy must be placed in statute***. As discussed below, the state's former success in encouraging CHP arose from both federal and state statutory reform.

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

Yes, for the purposes of formulating CHP policy at this time. The CEC should not, however, modify that methodology to reflect the reduction that may occur in a utility's RPS obligations when a MWh is self-served by CHP. The ICF Report states:

> *Analyzing greenhouse gas emissions in the context of all the other statewide reduction programs moving forward concurrently, particularly the RPS renewable percentage generation targets, results in a declining contribution to greenhouse gas emissions reductions over time. The reason for this reduction is that on-site CHP reduces utility demand for electricity. This demand reduction, in turn, reduces the amount of renewable energy capacity needed for utilities to meet their percentage targets. Therefore, with the RPS in place, the avoided*

utility emissions are only 67 percent of avoided emissions of the marginal fossil fuel electric system.[9]

Taking this broad approach to analyzing CHP GHG reductions seems unreasonable in light of other state policies. California has turned a blind eye to any indirect impact the RPS portfolio may have on the state's GHG emissions. The emissions associated with generation required to integrate, firm and shape renewable generation have not been accounted for in assessing the GHG benefits of the RPS portfolio. It thus seems inappropriate to take into account the indirect impact of CHP self-generation on the number of MWh needed to meet the RPS requirements. If, however, California seeks to view CHP through this lens, it must also broaden the analysis of RPS emissions impacts to include integrating fossil generation.

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?

The C-T program, all other things held equal, will detrimentally impact the development of non-utility-owned CHP. When a customer leaves the grid to self-serve its load using CHP generation, its direct carbon compliance obligation will increase. Moreover, its total carbon cost may increase as a result of installing CHP, depending on the outcome of the CPUC and CARB resolution of these issues.

Assume for illustration purposes that a PG&E customer has a demand of 50 MW and an annual usage of 400,000 MWh. Assume further that:

- ✓ The PG&E average grid carbon emissions rate is .25 MT/MWh, reflecting a blend of nuclear, hydro, renewable and fossil-fired emissions.
- ✓ The carbon emissions rate attributable to CHP electric deliveries, using a 1:1 heat to power ratio and after attributing emissions to heat using an 80% boiler proxy, is .43 MT/MWh.
- ✓ Cost of carbon is $30 MT.

Using these assumptions:

1) If the customer stays on the utility system, its direct carbon costs will be limited to boiler emissions. Assuming the energy value of the total heat and total electricity used are equal, the boiler emissions will be $2.7 million annually.[10] The customer will have indirect carbon costs for utility electricity

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[9] ICF Report at 123.

[10] 400,000 kWh = 1,364,800 MMBtu steam. To produce 1,364,800 MMBtu of steam at an 80% boiler efficiency rate requires 1,706,000 MMBtu of natural gas. Emissions from this amount of natural gas would equal 90,539 MT ((1,706,000 *117 lbs)/2204.6).

equal to $3 million annually (400,000 * .25 * $30). Total annual carbon costs for heat and power equal $5.7 million.

2) If the customer stays on the utility system and its carbon costs are offset using utility allowance value, the customer's direct carbon costs again will be $2.7 million annually for boiler fuel, and its carbon costs for electricity will be zero. Total annual carbon costs for heat and power equal $2.7 million.

3) If the customer leaves to install CHP, its direct carbon costs will include $2.7 million annually for heat and $5.2 million annually for power (400,000 *.43 * $30). Total annual carbon costs for heat and power will equal $7.9 million.

In short, because the utility's average cost of carbon reflects a blend of resources that cannot be duplicated – hydro, nuclear and certain renewable facilities – the direct carbon costs of CHP-generated electricity will always be higher than if the customer stayed on the grid. The distortion exists whether or not the CPUC uses utility allowance value to offset the carbon costs in rates. Consequently, a customer will have a clear financial incentive, all other things held equal, to stay on the utility grid. Moreover, the great uncertainty surrounding the C-T program roll-out will have a further chilling effect in at least the early program years.

The impact on a CHP developer should ***not*** be misunderstood to conclude that CHP is not a beneficial carbon reduction strategy. CHP creates higher GHG costs for the developer because its point of economic reference is its otherwise applicable utility rate, which reflects the average portfolio cost of emissions. The CHP resource cannot "compete" with this emissions rate because the portfolio blends the low emissions of historical utility investment in nuclear and hydro facilities (which can never be duplicated) and the 33% RPS into its overall emissions rate. Despite this disincentive for the CHP developer, CHP results in lower GHG emissions for society in general. In analyzing societal benefits, a CHP resource's emissions are compared not to the average utility emissions, but to the "marginal" system resource it displaces. Thus GHG benefits are determined by comparing the CHP emissions to separate heat and power emissions, including in all likelihood a "marginal" combined cycle gas turbine. The Commission must maintain an awareness of these differing reference points in conducting its analysis.

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.

Net metering is not an important feature for large-scale CHP, but could have relevance for smaller applications.

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?

Certain EPUC members are contemplating the installation of small AB 1613 CHP projects in the California oil fields. The availability of a feed-in tariff is a foundational element of a decision to install these projects. In combination with other problems identified for all CHP (*e.g.,* departing load charges), however, the curtailment provisions in the AB 1613 contract, as well as monthly scheduling fees, are barriers to development.

For CHP Developers and Project Owners

1) Comment on the following state programs and their influence on your project if it was available at the time of installation:

Self Generation Incentive Program incentives are very important to small projects.

The SGIP allows project developers to consider additional energy efficiency applications for bottoming cycle waste heat recovery. The incentives will be instrumental in the internal economic feasibility analysis. A variety of problems, however, can intervene and burden the project to infeasibility, including:

- Delay as a result of interconnection uncertainty;
- The inability to interconnect a small SGIP generator behind an existing interconnection, creating greater cost and defeating self-use; and
- Requirements limiting export percentages for incentives.

AB 1613 is an important consideration in small CHP projects.

Projects eligible for AB 1613 are also eligible for PURPA 20 MW and under contracts. So while AB 1613 is not critical to small CHP development, it expands the options available to these developers. In particular, the GHG related provisions, which allow for cost pass-through, provide greater certainty to developers than the PURPA framework.

Rule 21 is pivotal to timely development of small CHP.

Rule 21 worked very well for almost three decades, but the process currently presents nearly insurmountable uncertainty. At the very least, the uncertainty and costs of FERC-jurisdictional connection required today burden small project economics. The CHP Parties look forward to a more practical and lower cost process.

Cap & Trade is a material consideration in any CHP project economics.

See the response in the CHP Parties comments to Question II. 1).

2) Is your system capable of providing ancillary services? Does your interconnection agreement limit your ability to provide or be paid for those services?

Most existing CHP projects today can provide one or more ancillary services. Nearly all existing contracts, however, do not allow those products to be separately identified and sold in the market.

3) If applicable, how do air quality management district standards affect your CHP system's performance, emissions, and installation? Does your CHP system improve the level of emissions in the district it operates?

No response.

4) If applicable, how do local water quality board regulations affect your CHP system's installation/performance? Does your CHP system improve the water quality/reduce water use?

No response.

5) How was your project financed? Discuss any difficulties, unique situations, or special arrangements.

Most projects developed by the CHP Parties have been internally financed, either in whole or in part. The availability of internal capital can be important to investment in California during times when credit may be difficult to secure for generation projects. California must keep in mind, however, that internal capital for these projects must compete with other potential capital projects within a corporation. These competitive projects may be within California, but are equally as likely to be outside of the state. Thus, the thinner the return on a CHP project, the less likely it will be competitive within a corporation. Viewed from this perspective, mitigating barriers and reducing unnecessary cost burdens will advance capital investment in CHP in California.

6) What impact do departing load charges have on the viability or operation of your project?

Departing Load Charges are a significant barrier to entry. They factor into internal financial analysis and have a strong impact on the viability of small incremental energy efficiency projects. Although it varies by service territory, a project must be able to produce power cheaper than the local utility by the additional cost of the DLC. EPUC members have had at least two projects to self-supply that were not undertaken due primarily to the level of departing load.

7) If your project qualifies as renewable CHP, what were the barriers specific to a renewable-type project encountered? If yes, what were they? If they were overcome, how?

CHP, other than biogas or biomass CHP, are not renewable projects. Bottoming cycle CHP should, however, be considered a renewable technology. A pure bottoming cycle plant should be considered a renewable technology because the waste heat is recovered and generation produced without additional combustion but we were denied renewable energy status.

EPUC members have encountered problems with the potential installation of small renewable projects (not CHP renewable) behind an existing meter. A key factor in delaying or preventing these projects is the inability to install new small renewable projects behind interconnections with existing CHP PPAs. The utility concern appears to be the potential that installation of additional behind the meter generation could increase the exports from the existing generation. This issue is addressed further, above.

8) What impact do non-bypassable charges have on the viability or operation of your project?

See response to Question 6.

9) Is your project interconnected to the electric grid? If so, what interconnection procedure was used? Were there problems or unexpected delays? Was cost an issue? Were you able to get an interconnection agreement/FIT in a timely manner?

Nearly all CHP Party projects have been interconnected to the grid under Rule 21. Certain installations under development, however, are not yet interconnected. The complications of existing interconnection processes for small installations are a material barrier and have resulted in significant delays.

10) Does your project operate in a networked grid? What issues has this caused and how were they addressed?

Nearly all CHP Party projects are operating, having been developed under PURPA and Rule 21.

11) Can your project be dispatched?

While some CHP projects may be somewhat dispatchable, many have very limited dispatch potential due to the 24/7 nature of their industrial processes.

12) Can your CHP system run independently of the grid? Is your CHP system used for backup power? Does you facility act as an emergency shelter?

The availability of black start capability varies among projects.

13) Did your project involve a third party developer? What was their role in your project?

Some CHP Party facilities have involved a joint venture with the host and a third party, but only one has involved an entirely separate third party owner. In the latter case, the host later purchased the facility from the third party.

III. Technology Innovation to Overcome CHP Barriers

No response provided by the CHP Parties.

IV. QF Settlement and Infrastructure Planning

Questions for CPUC

No response provided by the CHP Parties.

Questions for the Investor-owned Utilities

No response provided by the CHP Parties.

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?

In all likelihood, yes. An existing QF resource is likely to be more price-competitive in an RFO than a new resource. New projects will need to recover their full cost of capital investment in their bid price, whereas some existing projects that may have already defeased their debt may be able to make lower economic bids.

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

No, not for the majority of CHP operations. In general, industrial customers that have installed CHP (or are the host for existing CHP facilities) are primarily focused on producing a product in a least-cost and reliable manner. Without a PPA, a CHP facility cannot provide the fundamental reliability and economic assurances that are critical to support industrial production. Uncertain revenues from generation offered into the CAISO Day-Ahead Market and capacity-related contracts that do not even reflect the elementary provisions necessary to sustain industrial production are too great a risk even for the more sophisticated industrial operators of existing CHP. Consequently, the CHP generator will most likely be unable to persuade an industrial host not to abandon CHP in favor of relying on IOU retail service for the electrical needs and self-supplying thermal requirements with non-CHP technology.

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?

See the list of actions required above in response to Question I.B. It is extremely unlikely that any developer would take the risk of installing a thermally matched CHP resource, where the electricity generated exceeds on-site needs, if it does not have a long-term PPA.

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 extent of on-site and export CHP will depend upon the robustness of power market opportunities, heat to power ratios of the developing projects and other factors. EPUC is not in a position to provide a meaningful response to this question.

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?

The CHP Parties do not have sufficient information to answer this question.

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.)

No response by the CHP Parties.

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

There are only two ways to ensure that a new CHP program will achieve the state's goals. The PURPA program relied on a "must take" obligation, as does the AB 1613 program. Alternatively, the RPS program uses percentage mandates. Either approach could be successful, but without one of these tools CHP is unlikely to develop.

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

If California seeks to jump-start a CHP program and invite ***large-scale*** development, each of the following actions is necessary in the near term:

- Provide secure, long-term opportunities to sell excess power into the market at compensatory prices;
- Eliminate departing load charges;
- Eliminate potential carbon-related disincentives to CHP development in CARB's cap-and-trade (C-T) program;
- Permit self-wheeling by a CHP facility to provide electricity to other commonly owned or affiliated operations;
- Reform scheduling requirements for resources with limited exports and highly variable thermal and/or electric loads behind the meter;
- Prevent utility interference with the installation of new facilities behind existing PPAs, by permitting a customer to determine which on-site generation will be used to serve its load; and
- Ensure that once installed, a customer may fully use its CHP output regardless of the on-site metering configuration.

Critically, to give these changes sufficient regulatory certainty to induce new investment, ***key elements of the state's CHP policy must be placed in statute***. As discussed below, the state's former success in encouraging CHP arose from both federal and state statutory reform.

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

Required actions are identified in the prior response.

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

No response by the CHP Parties.

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

No response by the CHP Parties.

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

No response by the CHP Parties.

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

CHP development occurred under PURPA in the 1980s as a result of two program features that reduced or nearly eliminated uncertainty. First, the program was enacted into federal law and supported by state statute. Statutory provisions provide greater certainty than do regulations that can shift with the ever-changing views of a regulatory agency. Second, California implemented long-term PPAs (the Standard Offers) with clear pricing options and used a strong hand to require execution of these contracts. The combination of these two features allowed utility customers to gain sufficient comfort to develop thousands of megawatts of CHP capacity. A statutory framework and clear, long-term, compensatory contract options would likely yield a similar result for new development.

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?

CHP power output from certain biogas arrangements today can be considered renewable. Output from CHP from traditional fossil fuels, however, could also be treated as a renewable in a reduced proportion. In other words a specific number of fossil-fired CHP MWh would equal 1 MWh of renewable energy. To determine a conversion value for CHP relative to RPS resources, however, RPS resources would have to be evaluated taking into account the emissions of firming and shaping resources and associated transmission losses.

While fossil-fired CHP would require a conversion factor, bottoming cycle CHP merits full renewable resource treatment. Bottoming cycle CHP can produce electricity, without supplemental firing, from waste heat that would otherwise have been released into the atmosphere. In this way, with emissions from the combustion of fuel resulting in the heat attributed to the underlying industrial process, bottoming cycle plants are essentially zero emissions resources. These resources thus should be included within the RPS portfolio on a one-for-one basis. Indeed, these resources may have greater overall value than other RPS resources because they do not require transmission upgrades, firming or shaping.

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?

No response by the CHP Parties.

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 CHP? What incentives are necessary?

The past utility role in CHP development in California has been limited to utility affiliates such as Edison Mission Energy. Beyond the utility affiliate structure, joint customer/utility projects that could be placed in ratebase are not inconceivable and have been done in other jurisdictions. Any such arrangement, however, would have to ensure that the customer would retain full operational control to protect the interests of the thermal host.

The CHP Parties look forward to further discussions with state policymakers on these issues.

Respectfully submitted,

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