**BEFORE THE CALIFORNIA ENERGY COMMISSION**
**OF THE STATE OF CALIFORNIA**

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| In the Matter of: | ) | |
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| 2014 Combined Heat and Power Staff Workshop | ) | Docket No. 14-CHP-1 |
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# Comments of the California Cogeneration Council on Combined Heat and Power


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On behalf of the
**CALIFORNIA COGENERATION COUNCIL**

August 18, 2014

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# Comments of the California Cogeneration Council on Combined Heat and Power

The California Energy Commission (CEC) conducted a workshop on July 14, 2014, to discuss the benefits, challenges, and practical solutions to encouraging the development of clean and efficient combined heat and power (CHP) resources in California. The California Cogeneration Council (CCC)[1] participated in the workshop, and with the Cogeneration Association of California (CAC) and the Energy Producers and Users Coalition (EPUC), gave a presentation identifying the benefits of CHP that should be quantified and considered in the pricing and valuation of CHP. [2]

The CEC workshop public notice invited written comments to be submitted by August 4, 2014, however, on July 25, 2014 CEC staff posted a list of questions requesting written comments, and the deadline was extended to August 18, 2014.

The CCC appreciates the opportunity to submit these comments and has responded to the questions section-by-section in the remainder of this document.

[1] The CCC is an *ad hoc* association of natural gas-fired combined heat and power facilities located throughout California, in the service territories of all three of California's major investor-owned electric utilities (IOUs) – Pacific Gas & Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E). In aggregate, CCC members' 30 different CHP projects generate 1,300 megawatts (MW) of power, most of which is sold to the IOUs. The CCC represents a significant share of the distributed CHP projects now operating in California.

[2] The CCC presentation is posted on the CEC website at: http://www.energy.ca.gov/chp/documents/2014-07-14_workshop/presentations/02_Tom_Beach_Presentation_to_the_CEC_CHP_Workshop-July_2014-CCC-CAC-EPUC.pdf

## A. INTRODUCTION

California state policy has long supported the development of cogeneration projects in California. Embedded in Section 372(a) of the California Public Utilities Code, "it is the policy of the state to encourage and support the development of cogeneration technology as an efficient, environmentally beneficial, competitive energy resource that will enhance the reliability of local generation supply, and promote local business growth."

California derives substantial benefits from installed CHP, beyond the electric capacity and energy that these projects sell to the utilities. These benefits include:

- **Efficiency**, through natural gas savings;
- **Environmental**, through lower air emissions (including reduced carbon emissions) from the production of power and steam sequentially rather than if both forms of energy were produced separately;
- **Economic**, by reducing the cost of energy to industry in California, thus helping to maintain the competitiveness of the state's economy in regional, national, and global markets;
- **Reliability**, by relatively high levels of availability to supply power to California as indicated by IOU performance data for CHP projects;
- **Distributed and deliverable** generation, by increasing the stability and reliability of the state's electric grid due to the wide geographical distribution of CHP facilities, and specifically the large number of CHP facilities in load centers; and
- **Resource diversity**, by increasing the diversity of the state's electric supply.

Building on these benefits, over the past decade numerous regulatory proceedings and resulting public policy statements have reconfirmed the state's commitment to support the continued operation of existing CHP, and the state's intent to encourage the development of new and efficient CHP. Specific recommendations regarding CHP can be found in the CEC's Integrated Energy Policy Reports (IEPR) (e.g., 2003, 2005, 2007, etc.) and specifically the 2012 CEC staff paper which identified barriers to CHP development and recommended specific actions to address these barriers.[3] The Energy Action Plan II identified the role of CHP in the loading order, and CHP continues to be considered a preferred resource in the long term procurement of resources.

> The Energy Action Plan II states: "The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation."

Both the California Air Resource Board's (CARB) 2008 Climate Change Scoping Plan and the First Update in 2014[4] identify the contribution that efficient CHP systems can make in reducing greenhouse gas (GHG) emissions.[5] Governor Brown set a goal for 6,500 MW of additional CHP capacity by 2030 as part of his Clean Energy Jobs Plan. This goal builds upon the Scoping Plan's goal for emission reductions equivalent to 4,000 MW of new CHP generation by 2020.

The CCC hopes that this CHP workshop will do more than produce yet another report that identifies the benefits of CHP, the barriers to new development, and makes recommendations that are then ignored by other regulatory agencies. The First Update to the Climate Change Scoping Plan (First Update) makes the following observation,

> "Despite these policy actions and incentives for CHP, significant installation barriers for CHP systems still remain and very few new CHP systems have been installed since the initial Scoping Plan was released. Indeed, due to older system retirements, the State's overall CHP capacity may be lower now than it was in 2008."

[3] Neff , Bryan. *A New Generation of Combined Heat and Power: Policy Planning for 2030*. 2012. California Energy Commission. CEC-200-2012-005
[4] CARB First Update to the Climate Change Scoping Plan, May 2014: http://www.arb.ca.gov/cc/scopingplan/document/updatedscopingplan2013.htm
[5] CARB 2008 Scoping Plan, at pages 43-44. http://www.arb.ca.gov/cc/scopinplan/document/adopted_scoping_plan.pdf

This reflects the harsh reality that companies previously operating CHP systems are choosing to install boilers or relocate operations, rather than develop new CHP. The lack of action by the state to address the barriers to CHP development has led to this exodus from the industry. Our plea, to not only the CEC but also the ARB, CPUC, and CAISO, is to initiate action now. The benefits from this valuable resource are being lost and inaction by the state will detrimentally impact California's industrial and manufacturing base as well as lead to an increase, rather than a decrease, in overall GHG emissions.

## B. CCC RESPONSE TO CEC QUESTIONS

### I. Market Characterization and the Benefits and Costs of Combined Heat and Power

**1. What benefits, if any, do existing small and large on-site and exporting CHP resources provide to electric utilities and the ISO?**

**5. What other categories of CHP benefit and cost are relevant, and how should each be defined and/or quantified in ways that are meaningful to the system and the State?**

**CCC Response:** the CCC's presentation to the July 14 CHP Workshop focused on the benefits of CHP to utilities, grid operators, and ratepayers which extend beyond the avoided costs for energy, generating capacity, and line losses that are typically included in the standard avoided cost prices which the utilities pay for power exported from CHP projects. The "non-traditional" benefits which the CCC discussed at the workshop can be quantified and should be considered in the pricing for CHP generation, in setting utility procurement targets for cost-effective CHP, and, generally, in formulating policies that are supportive of further development of efficient CHP facilities in California. The benefits which the CCC discussed include the following:

- **Avoided costs for transmission and distribution (T&D) capacity.** CHP projects often serve significant on-site loads and are located in load centers where their power exports are consumed by nearby loads without significant use of the transmission system. As a result, they allow the utilities and the CAISO to avoid the costs of transmission capacity. Similarly, smaller CHP projects may avoid distribution capacity costs. There are well-accepted methods to calculate long-run marginal T&D costs – for example, through a regression of long-term transmission costs as a function of the growth in peak demand. The California utilities have long used such methods to calculate marginal transmission and distribution costs for retail ratemaking purposes and for use in cost-effectiveness evaluations. The CCC listed such marginal T&D costs in its July 14 presentation:[6]

[6] SCE's last GRC (A. 11-06-007) shows a marginal cost for CAISO-controlled transmission of $59.18 per kW-year (2012 $). See A.11-06-007, SCE Workpapers, "MCCR" sheet, "Input Sheet" tab, cells D17-D19. The recent San Diego Distributed Solar PV Impact Study used a marginal cost of CAISO transmission for SDG&E of $102.83 per kW-year, escalating at 3% per year. See http://catcher.sandiego.edu/items/usdlaw/sd-distributed-solar-pv-impact-study.pdf at 38, Table 18. The other values in the table are from the CPUC's 2013 Net Energy Metering Study, at C-43 to C-45 and Table 12. See http://www.cpuc.ca.gov/NR/rdonlyres/C311FE8F-C262-45EE-9CD1-020556C41457/0/NEMReportWithAppendices.pdf. The SDG&E marginal subtransmission costs is the utility's marginal cost for distribution substations.

| Utility | CAISO High Voltage ($/kW-yr) | IOU Subtransmission ($/kW-yr) |
|---|---|---|
| PG&E | 19 | 20 |
| SCE | 59 | 24 |
| SDG&E | 103 | 22 |

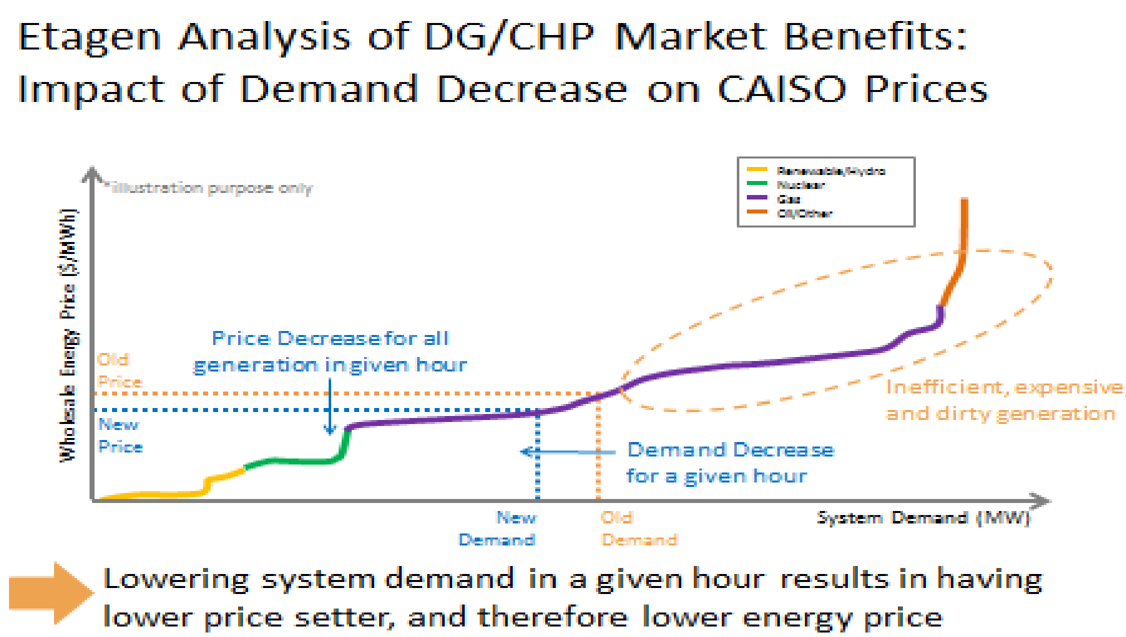
These avoided T&D capacity costs should be recognized and included in the payments which CHP projects receive for the capacity which they provide to the California grid.

- **Reductions in GHG Emissions.** The premise and promise of CHP is that it is a more efficient means to produce both the electric and thermal products needed at an industrial, commercial, or institutional facility. This efficiency results in lower emissions of greenhouse gases (GHGs). Efficient existing CHP projects, as well as thermally-balanced new CHP, exhibit higher efficiencies than the separate production of thermal and electric energy, as illustrated in the CCC's workshop presentation. Pacific Gas and Electric (PG&E) has suggested that CHP which serves on-site loads does not displace 100% marginal gas-fired generation. Instead, PG&E argues that CHP serving on-site loads displaces 67% gas-fired power and 33% renewable generation, because the reduction in utility sales lowers the utility's obligation under California's Renewable Portfolio Standard (RPS) program. As a result, PG&E suggests that the GHG emission benefits of CHP are minimal. However, this argument is no longer valid, given the passage in 2013 of AB 327, which clarified that the state's RPS goal is a floor, not a cap, on the amount of renewable generation which the utilities are to procure.[7] As a result, there is no longer a cap on the amount of renewable generation that is based on utility sales, and a reduction in utility sales as a result of CHP will no longer necessarily displace carbon-free renewable generation. In addition, the reality on the grid is that renewable generation has low or zero variable costs, so that the marginal generator is almost always a gas-fired resource, and the full power output from a new CHP unit will displace that marginal gas-fired generation in

[7] Public Utilities Code Section 399.15(b)(3), enacted as part of AB 327, authorizes the CPUC to have the utilities procure more renewable generation than the RPS goal.

most hours. For these reasons, efficient CHP is a cost-effective means to reduce carbon emissions and should be an integral part of the state's AB 32 program.

- **Market price mitigation.** It is basic economics that a reduction in the demand for electricity, or an increase in the supply, will reduce the market price for power. CHP which serves on-site load will reduce the demand for electricity in the CAISO's market (shifting the demand curve to the left), thus lowering the market price for electricity for all purchasers in that market.




Source: Drawn by EtaGen Inc. based on real CAISO supply stack data reported by Dynegy Inc.

Similarly, exports of CHP generation will be an infra-marginal, price-taking source of power, and thus will reduce market prices by increasing the available supply (shifting the supply curve to the right). The CHP developer Etagen has done important recent work to quantify this benefit in the CAISO market; this benefit is on the order of $20 per MWh. This benefit has also been quantified in the New England ISO market, and is used in New England in cost-effectiveness evaluations of demand-side programs.[8] The CCC agrees

[8] In the New England ISO markets, the price mitigation benefit, called the demand reduction induced price effect (DRIPE), has been estimated at 19-25% of combined energy and capacity prices . *See* Synapse Energy Economics,

with Etagen that the magnitude of this benefit fully justifies important and necessary policy changes such as the removal of departing load charges and exit fees from CHP which serves on-site loads.

- **Reliability and resiliency.** Events such as Superstorm Sandy have emphasized the importance of developing supplemental, distributed generation, as alternatives to traditional grid power, because during extreme weather events the grid cannot be relied on as the sole source of power. CHP units can serve as the foundation for local micro-grids to provide a resilient local source of generation for critical governmental or institutional customers. Even when the grid is operational, distributed generation resources will increase stability and reliability: they are installed as many small systems and are highly unlikely to fail at the same time. They also are located at the point of end use, and thus reduce the risk of outages due to transmission or distribution system failures. Not surprisingly, this benefit is difficult to quantify; one high-level estimate of the benefits of a 5% increase in reliability from the more widespread use of distributed generation resources is a 20-year levelized benefit of $22 per MWh.[9]

In conclusion, the prices paid for CHP exports should include at least one of the above benefits – avoided T&D capacity costs. The CPUC should recognize the other benefits – GHG emission reductions, market price mitigation, and reliability benefits – by continuing to set utility procurement targets for efficient existing and new CHP and by eliminating the departing load charges and exit fees that represent a real economic barrier to new CHP projects.

**2. What benefits/attributes do grid operators want from new CHP resources? Under what circumstances can CHP provide those characteristics?**

**CCC Response:** Given the mission of grid operators such as the CAISO, it is not surprising that they are most interested in resources that are fully dispatchable. CHP resources generally are not fully dispatchable because, to achieve high efficiencies, they must operate to meet a significant thermal

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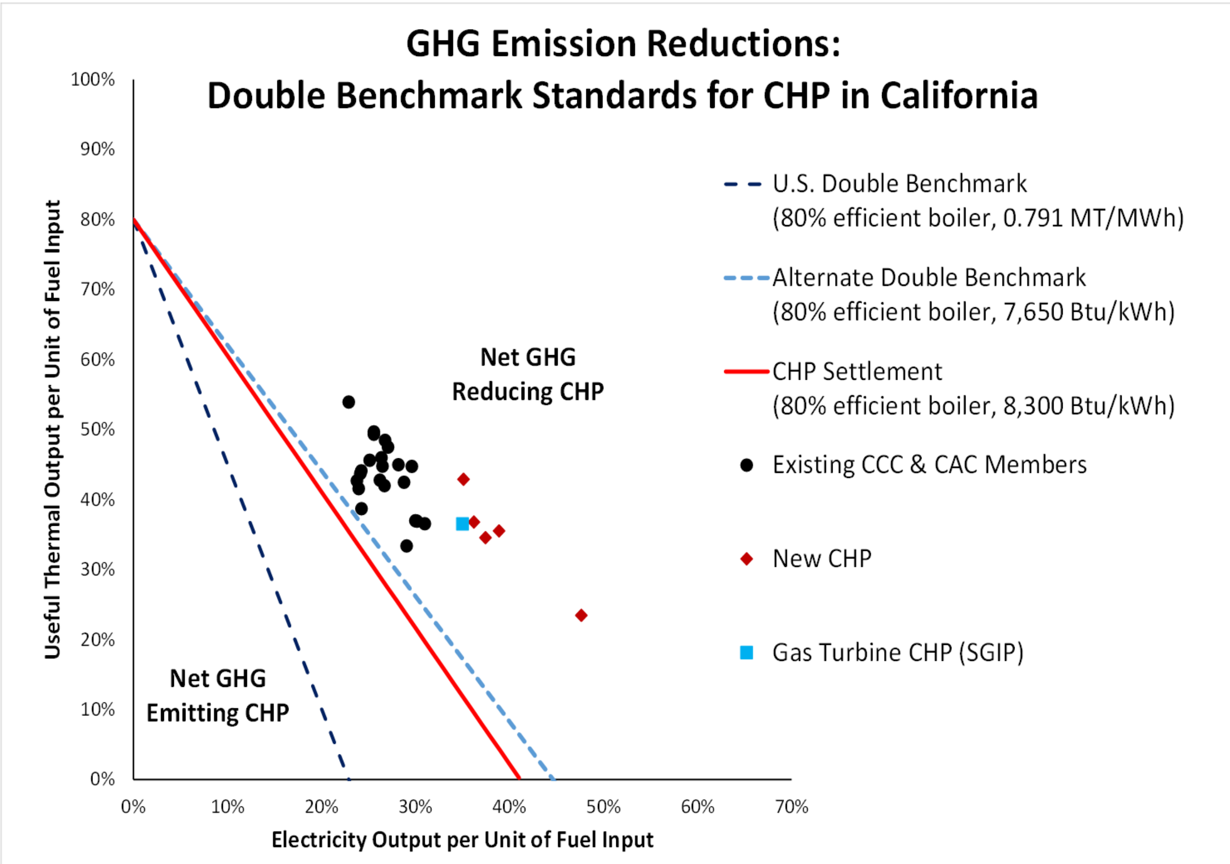
"Avoided Energy Supply Costs in New England: 2011 Report" (August 11, 2011), at Exhibit 1-1. Available at http://www.synapse-energy.com/Downloads/SynapseReport.2011-07.AESC.AESC-Study-2011.11-014.pdf .

[9] Hoff, Norris, and Perez, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania* (November 2012), at Table ES-2, available at http://mseia.net/site/wp-content/uploads/2012/05/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf.

demand. However, due to the wide range of thermal needs which CHP units serve, each unit is unique in its design and in the constraints under which it operates. As a result, many CHP units can offer some degree of useful flexibility to the grid. The CCC recognizes that the CAISO and the CPUC are developing new market mechanisms that will price the flexibility attributes of generation in California. The definition and pricing of these attributes should be as transparent as possible, so that CHP operators and developers can understand the economic value of the flexibility that their projects may be able to provide. For example, the CAISO and CPUC should require the utilities to make transparent the current prices for the flexible resource adequacy capacity that the utilities soon will be required to procure.

3. **Access to useful operational and economic data from utilities and CHP system owners is often restricted.**
   a. **What currently unavailable types and/or sources of data would allow for more complete and accurate analysis of the benefits and costs of CHP?**
   b. **How should this data be collected, obtained, and/or distributed?**

**CCC Response:** The CCC appreciates that data on the on-site electric and thermal use from CHP projects is important data to assess the overall efficiency of CHP resources. At the same time, this data is commercially sensitive for the host facilities. The CCC is willing to work with regulators and the utilities to present such data in masked or aggregated form – such as the "double benchmark" efficiency data from existing CHP units which the CCC presented at the workshop, reproduced below.




**4. What CHP cost studies are needed to better understand and compare CHP resources to other resources?**

**CCC Response:** The CCC suggests that the CEC should consider conducting a survey, perhaps with the assistance of the U.S. EPA, of the costs and efficiency of new CHP projects throughout the U.S. This survey could be conducted and published in a manner similar to the CEC's highly useful Cost of Generation studies from past IEPRs.[10]

[10] "Comparative Costs of California Central Station Electricity Generation Technologies" (CEC Staff Final Report, January 2010, CEC Publication CEC-200-2009-017-SF). This CEC report is available at http://www.energy.ca.gov/2009_energypolicy/documents/index.html#082509 .

## II. Economic Barriers & Regulatory Challenges to Combined Heat & Power

**CCC Response:** Any consideration of economic barriers and regulatory challenges to CHP development must consider, as a threshold matter, the issue of the utility business model. A regulated utility's authorized return is a percentage of its rate base; thus, its earnings grow as its rate base increases. This presents the utility with a fundamental conflict of interest when it comes to pricing and policies applicable to customer-sited distributed generation (DG) such as CHP. Long-term DG resources such as CHP have the ability to displace the utility's own rate-base investments in generation, transmission, and distribution. CHP can serve customers with a wide variety and size of thermal and electrical loads. Perhaps most important, there is strong customer interest in supplying a portion of their energy needs with DG or in bypassing the grid entirely. These trends present the utility with the uncomfortable prospect that its future role, size, rate base, and earnings may not be as large as it expects. DG represents competition for the utility. This conflict has convinced many observers that the utility business model in the U.S. needs to change. A former chairman of the Colorado Public Utilities Commission, Ronald Lehr, recently wrote:

> Much of the U.S. electric power sector has changed little over the past 100 years. But the industry now faces an unfamiliar and uncertain future. Potent new pressures are building that will force fundamental changes in the way that the electric utilities do business. Consumers are demanding a new relationship with the energy they use, and new technologies are proliferating to meet demand. At the same time, innovative new technologies and suppliers have come on the scene, disrupting relationships between traditional utilities, regulators, and customers.
>
> If the U.S. is to meet necessary climate goals with electric utilities remaining healthy contributors to America's energy future, business models used by these familiar institutions must be allowed and encouraged to evolve. This agenda has implications not only for companies themselves, but also for the legal and regulatory structures in which they operate. A new social compact is needed between utilities and those who regulate them….[11]

This larger discussion about the future business model for the utilities has already begun in several states, including New York and Hawaii.[12] It needs to begin in California as well, and

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[11] See Ronald Lehr, "New Utility Business Models: Utility and Regulatory Models for the Modern Era," part of America's Power Plan, available at http://americaspowerplan.com/site/wp-content/uploads/2013/10/APP-UTILITIES.pdf.

[12] See Hawaii PUC, "Commission's Inclinations on the Future of Hawaii's Electric Utilities: Aligning the Utility Business Model with Customer Interests and Public Policy Goals," available at http://puc.hawaii.gov/wp-

should include discussions on the future role of customer choice and customer-sited generation. Debates about the future role of CHP, such as those presented at the July 14 workshop, are unlikely to reach final resolution until there is greater clarity and transparency on the utility's future role, size, and financial incentives in a rapidly changing energy landscape. In sum, if the state truly is interested in meeting its goals for the retention and development of new CHP, the utilities must be encouraged to procure CHP rather than incentivized to block or discourage it.

1. **What are the most significant economic factors that contribute to the decision by a public or private developer to invest in CHP (e.g. upfront cost, ongoing operation and maintenance, electricity rates, price of natural gas, internal business decision making processes)?**

**CCC Response:** First, CHP developers will consider the expected return on, and payback period for, their upfront capital investment in CHP. The CCC's experience is consistent with the adoption metrics used in past *CEC CHP Market Assessments* – simple payback periods of five years or less are critical if there is going to be any significant additional penetration of CHP facilities.[13] Thus, the savings on natural gas and electricity costs at the host facility, plus revenues from power sales to the utility, from a new CHP project must pay off the expected capital costs in five years or less. Notably, simple paybacks consider only the return of the investment, not the return on the investments, taxes, or other financing costs. These relatively short simple paybacks are in significant part a result of the limited terms of the power purchase contracts available to CHP developers – 10 years under AB 1613 and 12 years under the QF/CHP Settlement. Currently available contracts or feed-in tariffs for CHP projects, such as the AB 1613 tariff, can meet this hurdle, but only for the most efficient projects at sites where interconnection costs are low. Thus, virtually no meaningful development of CHP has occurred under AB 1613.

Second, beyond the basic economics of CHP, developers will consider the risks and barriers to successful project development. These risks include siting, interconnection, environmental permitting, and ongoing regulation of operations (such as evolving GHG regulations). It is

content/uploads/2014/04/Commissions-Inclinations.pdf. See New York PSC, Docket 14-M-0101, "Reforming the Energy Vision," at http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument .

[13] ICF International for the CEC, "Combined Heat And Power: Policy Analysis and 2011 – 2030 Market Assessment" (February 2012, Publication CEC-200-2012-002), at 112-113, Figure 33, and Appendix A. Hereafter, "CEC CHP Market Assessment." See http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf.

important that developers can see a feasible path through these obstacles to successful project completion. Today, such visible successes are few: for example, only one AB 1613 project has been developed successfully since that legislation was enacted in 2007 (Houwelings Tomatoes), and the history of that project is harrowing enough to discourage mere mortal developers who lack to the passion and dedication of a Casey Houwelings.

Finally, CHP customers also assume fuel price, maintenance, and operating risks for their generation which otherwise would be borne by the utility and their ratepayers. Developers and CHP hosts must be comfortable with, and compensated for, assuming these risks.

2. **What impacts do departing load charges have on the viability of developing new CHP resources?**
   a. **How do these impacts compare to the net impacts of CHP generation on ratepayers?**
   b. **What analyses and/or studies are needed to fully quantify CHP impacts?**
3. **Are exit fee allocations that continue indefinitely, without transition or restriction, appropriate for CHP facilities? If not, how should exit fees be allocated over time?**

**CCC Response:** Departing load and other non-bypassable "exit fees" can reduce the economic benefits of CHP projects serving on-site loads by 1.5 to 3.0 cents per kWh. This reduction in savings for the CHP host often can be the difference between viable and non-viable CHP projects, particularly for smaller CHP units that are efficiently sized to the host's thermal needs and that principally serve on-site electric loads. In addition, utility tariffs and rules concerning these charges are numbingly complicated, as shown by the attached tabular summary of the applicability and exemption provisions for SCE's Customer Generation Departing Load Cost Responsibility Surcharge (refer Attachment 1). This is one page of SCE's nine-page tariff delineating these charges for customers who seek to be served from on-site generation such as CHP. Even mastering the intricacies of this tariff does not tell you what your departing load charges will be, as this tariff actually includes almost no rates, but refers you to other utility tariffs to find the exact charges.

Stepping back, these exit fees originated in the mid-1990s, when the state was preparing for its ill-fated deregulation exercise, which lasted from 1998 until the 2000-2001 energy crisis. These charges originally were designed to ensure that all utility customers contributed to "transition" costs – principally the above-market costs of the nuclear plants and QF contracts dating from the

1980s. The protection afforded by these fees was supposed to end once the transition had been completed to a market in which customers could choose their source of generation. Both the energy crisis and the costs of 1980s-era generation are now almost entirely behind us, yet these exit fees have survived because the utilities successfully have adapted them to limit the competition that they might face from customer choice, in the form of direct access, community choice aggregation, municipal utilities, or customer-owned generation.

In effect, the result of these charges is that it is difficult to compete with the fossil-fuel generation that contributes to the utility generation portfolio unless you can supply generation at or below CAISO short-run, spot market energy prices plus a small uplift for the above-market costs of RPS renewable generation.[14] These short-run energy prices typically are much lower than the long-term costs of new generation which has to recover full capacity costs. Given that much of the "competition" that the utilities face today from other providers, including CHP, is from generation that would be cleaner or more efficient than the existing fossil-fueled generation that is the marginal supply source for the CAISO market and the utility portfolios, it is questionable whether these exit fees still advance a legitimate public policy interest. In effect, departing load charges and exit fees act as a barrier to new, cleaner, more efficient generation by forcing the new generation to compete against short-run energy market prices.

Furthermore, a large component of the departing load charges are for the utilities' public purpose program (PPP) costs and the costs of the DWR bonds incurred during the 2000-2001 crisis. Customers who install CHP or other types of DG often are criticized for not paying these PPP and DWR charges on the power that they supply to themselves or their hosts from their on-site generation. The same issue is present when a customer reduces his usage through energy conservation, yet this issue does not seem to be controversial in that context. In both cases, the customer is acting to improve the efficiency of his energy use and to reduce his reliance or demand contribution on the grid. For example, PPP charges include the costs for utility energy

[14] For example, the non-bypassable PCIA Charge is based on the difference between the generation component of the customer's retail rate and the short-run cost of market power plus a small adder for the above-market costs of renewable generation. New CHP serving on-site loads is not necessarily exempt from the PCIA charge. As a result, a new CHP project serving on-site loads can offer generation cost savings to the on-site customer only if it can beat short-run market prices plus the small RPS uplift. SCE's Power Charge Indifference Adjustment (PCIA) Charge is shown at https://www.sce.com/NR/sc3/tm2/pdf/ce144-12.pdf.

efficiency programs, and it would seem to be equitable to allow customers to avoid these costs if they make significant efficiency improvements through long-term investments in CHP, DG, or EE. Similarly, a customer who invests in distributed generation is helping in a direct, long-term fashion to ensure that the California energy market cannot be manipulated as it was in 2000-2001. A DG customer who makes such a long-term investment should be excused from a share of the DWR bond costs.

More broadly, there are public benefits from private investments in DG. The dollar amounts that a CHP or a solar PV project contributes to advancing a public purpose (efficient energy use, reduced GHG emissions, and/or renewable energy development) through its long-term investment in DG is far greater than the public purpose program costs which it avoids. For example, a PG&E E-20T industrial customer with a load of 5 MW and a 75% load factor pays about $500,000 per year in PPP charges and DWR bond costs, but such a customer would invest tens of millions of dollars to use CHP to serve this load and the associated thermal demand, and thus to advance the public purposes of efficient energy use and reduced GHG emissions. The environmental, reliability, and energy security benefits of CHP and other DG technologies are funded through the private investments of customers but are realized by all, including non-participants. This justifies not requiring customers who install DG also to pay for the costs of the utility's public purpose programs.

4. **What regulatory challenges and barriers lead to new-CHP project delays or failure (e.g. interconnection process, financial incentives, contracting issues, cap and trade)? Please provide specific examples of how these challenges were, or were not, overcome.**
5. **What regulatory changes, if any, are needed to better balance utility interests, CHP developer interests, thermal host needs, and State GHG reduction targets?**
6. **A key feature of AB 1613 is that it allows for export and payment of excess electricity.**
    a. **Does the current AB 1613 feed-in tariff provide enough financial support to enable individual projects to be sized and developed with appropriate technology to meet the thermal load of the host facility?**
    b. **How does the availability of the feed-in tariff affect your decision to pursue a CHP project in California?**
    c. **Are there any deficiencies in the current implementation of AB 1613? Please explain.**
    d. **What should be done to better inform project developers about the requirements of the ISO and utility interconnection processes for electricity export**?

**CCC Response:** The CCC principally represents existing, operating CHP projects. However, some CCC members have considered developing new or repowered CHP projects, both under the 2010 QF/CHP Settlement and AB 1613. The CCC is aware of the following significant regulatory challenges and barriers which have led to delays or failure of new CHP projects.

- **10- or 12-year Contracts for New CHP.** With respect to new CHP, a major problem with the QF/CHP Settlement is the provision that limits utility contracts with new CHP to no more than 12 years. Similarly, the AB 1613 program limits contracts for new CHP to terms of 10 years, even though the capacity component of the AB 1613 price assumes that the plant is financed over a 20-year period. A CHP developer will have difficulty financing a new long-term investment for generation facilities with useful lives of 30 years or more based on just a 10- or 12-year contract. If the full return on and recovery of the cost of a capital investment in a CHP facility needs to occur over a 12-year period rather than a longer period, the cost of electricity purchased under the power purchase agreement must be priced higher, which is detrimental to the utility ratepayer. The capacity price that the developer must bid for a 12-year contract will be inflated because the developer has no assurance of an off-taker for the project's capacity after the initial 12 years. The resource also appears to be less competitive as compared to resources receiving longer-term contracts. Recovery over a longer period of time through longer-term contracts with lower pricing benefits ratepayers.
- **Utility focus on UPFs and low-cost RA capacity from CHP.** The results from the initial solicitations in the First Program Period (November 2011- July 2015) for the QF/CHP Settlement show clearly that the utilities have focused on (1) CHP conversions to utility-prescheduled facilities (UPFs), and (2) low-cost resource adequacy capacity from CHP. The result is a CHP portfolio with an emphasis on low costs, with most of the GHG emission savings coming from CHP conversions to peaking plants, not from new CHP. Regrettably, the utilities' implementation of the CHP program thus far has not resulted in the retention of many efficient CHP units, which was clearly one of the primary goals in the CPUC's adoption of the CHP program. As the CHP program now stands, the CCC has little confidence that this will change in the future unless the CPUC makes further refinements in the CHP program.

- **Interconnection.** San Joaquin Refining, a small refinery in Bakersfield that does not have CHP, spent three years and significant resources at both the CPUC and FERC participating in the development of the AB 1613 feed-in tariff. Although a 20 MW, high efficiency AB 1613 CHP project at San Joaquin Refining would have been economic under the resulting AB 1613 contract, the refinery was not able to develop its project as a result of the prohibitive costs and delays that the refinery encountered in trying to work with PG&E on interconnecting the project. Houwelings Tomatoes also encountered major difficulties in the interconnection process for its project in SCE's service territory. As stated above, utility incentives need to be aligned with state policy goals so interconnection cannot be used to discourage further CHP development. Expedited interconnection procedures need to be implemented.
- **Marginal economics.** The pricing in the AB 1613 contract was established in 2009, based on the costs and efficiency of a 500 MW combined-cycle power plant used in the CPUC's 2009 Market Price Referent, plus at most a 10% adder for avoided T&D costs.[15] This pricing has not been updated since then. The current AB 1613 contract is, at best, a marginally-economic contract for a new small CHP project which will not enjoy the same economies of scale as a 500 MW combined-cycle. The economics of small CHP projects could be enhanced markedly with a more thorough recognition of the benefits of small CHP – particularly, as discussed above, the capacity-related T&D benefits that can be realized by a small CHP unit located behind the meter or exporting power to the lower-voltage T&D system in load centers.

## III. Meeting California's CHP Goals

1. **Is there adequate economic and technical potential for CHP resources to achieve State goals set out in the Governor's Clean Energy Jobs Plan (6,500 MW of new CHP capacity by 2030) and the Air Resource Board's Scoping Plan for AB 32 (6.7 MMTCO2E annual emissions reduction by 2020)?**
2. **How should the State meet these goals?**
3. **Should the State set CHP procurement targets to address specific CHP facilities, projects, or technology types (e.g. existing efficient CHP, bottoming-cycle CHP, renewably-fueled CHP, new highly-efficient CHP)?**

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[15] See D. 09-12-042, as modified by D.10-04-055, D.10-12-055, D.11-04-033, and Resolution E-4424.

4. **Do the eligibility requirements of existing CHP programs align with market needs? If not, what changes are needed to stimulate market participation?**

**CCC Response:** The CCC agrees with the CEC's most recent CHP Market Assessment that these goals can be approached, but only with a comprehensive suite of supportive state policies.[16] The CCC's current list of such policies include:

- CHP procurement targets for the utilities
- Refined procurement criteria that capture efficient CHP, including existing efficient CHP
- 20- to 30-year power purchase contracts
- Full value recovery for products sold to utilities from CHP facilities
- Inclusion of avoided T&D capacity costs in the prices paid for CHP units
- Higher priority in utility procurement to CHP projects which reduce GHG emissions
- Streamlined interconnection procedures
- Removal of departing load charges and exit fees
- Incentives to encourage utilities to procure CHP rather than oppose it

## IV. Technology Innovation to Overcome Combined Heat & Power Barriers

1. **What are new opportunities and applications for on-site and exporting CHP resources both large and small (e.g. CHP coupled with Carbon Capture Utilization and Sequestration technologies, energy storage for excess electricity, thermal storage for excess thermal energy)? How should the state encourage these technologies (e.g. bottoming-cycle/waste heat to power, use of renewable fuels, microgrids)?**

2. **Which technologies, systems, components, and applications should RD&D prioritize to advance the capabilities and opportunities of both small and large CHP?**

## V. Electrical Generation Unit and Reference Boiler Efficiency

**Double Benchmark accounting is a methodology for determining fuel savings when a CHP system displaces thermal and electrical energy that would have been generated separately. This method requires energy conversion efficiencies for the displaced thermal and electrical resources, usually given in the form of a reference boiler efficiency and an effective grid heat rate. Determining these efficiencies is a complex problem, and the best method for doing so remains an open question.**

[16] See the CEC CHP Market Assessment, at pages 5-11.

1. **How should CHP systems be categorized, if at all, for the purpose of comparing them to separate heat and power (e.g. size, technology type, application)?**

2. **What method(s) should be used to determine the effective heat rate of displaced grid electricity? What key factor(s) should be considered (e.g. operational capabilities, time of day, line losses)?**

3. **What method(s) should be used to determine the efficiency of displaced thermal resources? What key factor(s) should be considered (e.g. thermal load size, thermal utilization level, historical equipment purchases/performance, new technologies)?**

4. **How can the State measure and quantify thermal utilization for the purposes of determining the GHG emission reduction benefits of CHP? Should all CHP facilities be required to meter useful thermal output and report that information to state agencies?**

**CCC Response:** The CCC supports the use of a reasonable double benchmark for assessing the efficiency of, and the GHG emission reductions from, CHP projects. The purpose of a CHP facility is the efficient production of two products: electrical and thermal energy. As a result, it makes sense to use a double benchmark that calculates the input energy that would be required for the separate production of the same two electrical and thermal products, for comparison to the input energy used in the CHP facility.

In determining the efficiencies to use in the double benchmark, it is important to use average, "typical" values, not the lowest gas-fired heat rate or the highest available boiler efficiency. On the electric grid, CHP generation will displace marginal generation with a range of efficiencies, depending on the time of day, day of the week, and season of the year. The displaced generation will also be the marginal, least efficient unit in the market at that time. Similarly, the thermal output from a CHP unit will replace the output of a "real world" steam boiler that is unlikely to operate at its maximum efficiency. Use of hypothetical benchmarks not reflecting operating realities only serves to discourage the development and operation of CHP.

There are a variety of approaches, of increasing complexity, for determining the effective heat rate of displaced grid electricity. The staff's fuel displacement method is a relatively simple, transparent, and understandable approach. However, it is based largely on the average heat rates of fossil generation, and, as explained more fully below, may not capture fully the marginal heat rates and marginal line losses that are the most accurate metric of fuel displacement. Analysis of historical and forward market prices for electricity and gas in the CAISO markets is another useful, market-based approach for estimating marginal heat rates. The analysis of market heat rates is somewhat more granular than the staff's approach and uses widely available market data. Finally, the most complex, comprehensive – and opaque – approach is production cost modeling, such as SoCalGas presented at the workshop. Production cost models can incorporate future impacts such as increasing penetrations of renewable resources and changing patterns of load growth, such as the growth of electric vehicle use. All of these methods can provide useful results – the best result would be to obtain similar values for the marginal heat rate using more than one of these approaches.

## VI. Energy Commission Staff Proposed Methodology for Estimating Fuel Displacement

1. **Is the Energy Commission staff's approach to estimating fuel displacement reasonable? If not, please explain why.**

2. **Is the Energy Commission staff's approach to the treatment of renewable energy appropriate? If not, please explain.**

3. **How could the method be applied across programs so that it creates beneficial comparison without interfering with existing program-specific displacement metrics?**

4. **Is the use of annual heat rate values (versus seasonal values) sufficient given the purpose and scope of the method? If not, please explain and propose an alternative.**

5. **Is the use of a single, state-wide heat rate projection appropriate? If not, please explain and propose an alternative.**

6. **Is the use of two heat rates categories (peaking and load following) adequate? If not, please explain and propose an alternative.**

7. **Does the approach sufficiently address the issue of imported electricity? If not, please suggest ways that it could be improved.**

8. **Do you agree with the line loss factor used? If not, please explain and propose an alternative.**

9. **Do you agree with the heat rate floor used? If not, please explain and propose an alternative.**

**CCC Response:** The CCC believes that the CEC's fuel displacement methodology is a simple, transparent, and understandable approach to a reasonable "ballpark" calculation of the minimum amount of fuel displaced by a range of different demand-side and CHP resources. Our principal concern with the CEC's method is whether the use of average heat rates for fossil generation accurately captures marginal system heat rates. There are two dimensions to this concern. First, when demand-side and CHP resources displace the marginal resource (which in most hours will be a gas-fired resource[17]), the short-run impact on the last MMBtu of fuel consumed would be indicated by the marginal heat rate, rather than the average heat rate, of the gas-fired generators on the system. Second, CHP does not displace just the marginal MMBtu of fuel use. California has a large block of existing CHP resources – on the order of 8.5 GW including generation serving on-site loads[18] – and thus CHP power displaces a significant amount of gas-fired generation which is much less efficient than the marginal resource. As a result, the marginal heat rate is a measure of the <u>minimum</u> amount of fuel displaced by CHP resources. Furthermore, as discussed above in conjunction with the market price mitigation benefit of CHP, CHP generation reduces market prices generally, across the entire net short position of the utilities in the CAISO market, which multiplies the benefits of this generation beyond the cost of just the marginal resource whose fuel burn is displaced. This effect does not change the amount of fuel displaced, but does increase the market price benefits of this displacement for all energy consumers in the state.

There are several implications of these observations for the CEC's fuel displacement study. First, the study should not be used as an indication of the energy costs avoided by CHP generation, because it presents only the minimum amounts of fuel displaced and of market costs avoided by this generation.[19] Second, it sets only a lower bound on the amount of greenhouse gas emission reductions which should be attributable to the power production from CHP facilities. In reality, the state's fleet of CHP resources will avoid more pounds of

[17] Natural gas is almost always the marginal fuel in California. It is only at certain times, i.e. late at night or during the spring hydro runoff season, that the displaced resources may be other than gas-fired generation.

[18] See the CEC CHP Market Assessment, at page 1.

[19] Generally, the FERC rules implementing the avoided cost pricing provisions of PURPA require states to consider the aggregate value of QF capacity in setting avoided cost prices. See 18 CFR Part 292.304(e)(2)(vi). This requires consideration of the fuel displacement and market price impacts of the entire block of QF capacity.

carbon emissions per MWh than is indicated by emission reductions from the last, marginal MWh of CHP generation added to the system.

With these caveats in mind, we have looked at the CEC staff's fuel displacement analysis, and provide the following analysis as a check on the staff's results. Market price data from the gas and electric markets in California can provide a useful measure of the marginal system heat rate as a check on the CEC's results. Calculating a market heat rate based on such price data implicitly will include consideration of how much of the time various resources are on the margin and their incremental costs.

Historical electric market prices in the California market can be obtained from the CAISO's day-ahead markets. The NP-15 and SP-15 trade hubs provide hourly prices that can be averaged by month to determine historical monthly electric market prices. Forward markets exist for the NP-15 and SP-15 trade hubs as well, which allow one to forecast monthly average electric market prices for several years into the future. On the natural gas side, monthly average prices can be obtained from a number of trade publications, as well as from the CAISO, which lists on its OASIS website daily burnertip prices for electric generation by utility service territory. Forward market prices for natural gas, at locations such as the Topock, Arizona / Southern California border, or the PG&E City-gate are readily available from sources such as the Chicago Mercantile Exchange (CME), NYMEX, and the Natural Gas Exchange (NGX) in Calgary, Alberta. To calculate forward market prices at Topock or the PG&E City-gate, one must add the CME-reported basis differentials from these markets to the NYMEX-reported Henry Hub forward market price. Finally, intrastate gas transportation charges must be added to PG&E City-gate or Topock border prices to obtain burner-tip gas prices for electric generators. In addition, market prices for greenhouse gas (GHG) allowances can be estimated from the Air Resource Board's quarterly auctions, and from other sources (e.g. the CAISO's reported daily allowance prices). GHG allowance prices impact electric market prices, and these impacts must be removed from market prices in order to estimate actual fuel displacement. Combining these pieces of information leads to a calculation of historical and forecast market heat rates in northern (NP-15) and southern (SP-15) California, as shown in the following tables, which provide an exemplary calculation of 2013 to 2016 market heat rates for northern and southern California, respectively. For simplicity, this tables show annual average values, but it is a simple matter to do the calculation on a monthly basis, the results of which we show in the figure after the two tables.

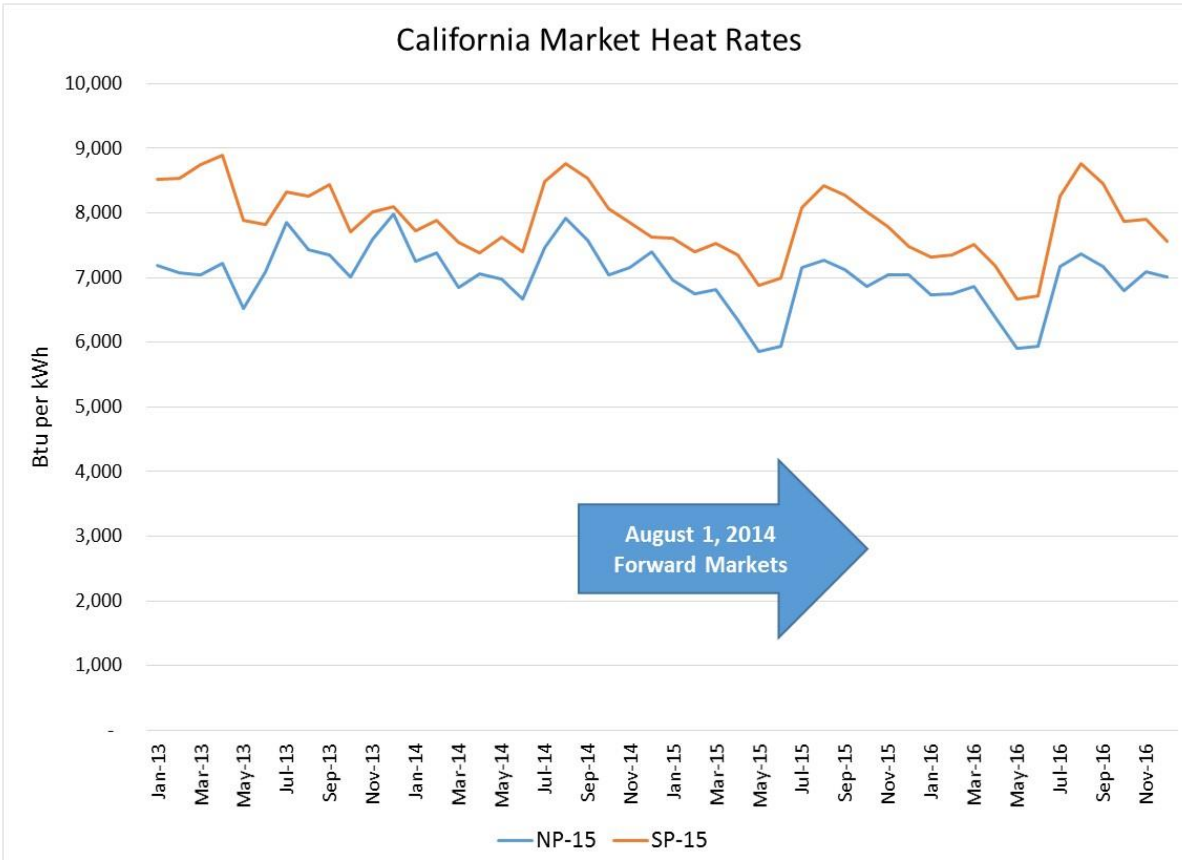
**Example NP-15 Market Heat Rate Calculation**

| Year | NP-15 $/MWh | PG&E Citygate $/MMBtu | Intrastate Transport $/MMBtu | Burnertip Gas Cost $/MMBtu | GHG Allowance as $/MMBtu | Variable O&M $/MWh | Heat Rate Btu/kWh |
|---|---|---|---|---|---|---|---|
| 2013 | 40.58 | 3.97 | 0.47 | 4.44 | 0.72 | 3.02 | 7,282 |
| 2014 | 47.36 | 4.91 | 0.59 | 4.50 | 0.63 | 3.08 | 7,221 |
| 2015 | 41.15 | 4.40 | 0.58 | 4.99 | 0.63 | 3.14 | 6,769 |
| 2016 | 42.52 | 4.57 | 0.58 | 5.16 | 0.65 | 3.20 | 6,771 |
| Average | | | | | | | **7,011** |

*Note: Market Heat Rate = (Electric Price – O&M) / (Gas Cost + GHG Price) x 1000*

**Example SP-15 Market Heat Rate Calculation**

| Year | SP-15 $/MWh | SoCal Border $/MMBtu | Intrastate Transport $/MMBtu | Burnertip Gas Cost $/MMBtu | GHG Allowance as $/MMBtu | Variable O&M $/MWh | Heat Rate Btu/kWh |
|---|---|---|---|---|---|---|---|
| 2013 | 43.72 | 3.83 | 0.38 | 4.20 | 0.72 | 3.02 | 8,269 |
| 2014 | 46.88 | 4.60 | 0.32 | 4.92 | 0.63 | 3.08 | 7,890 |
| 2015 | 41.40 | 4.08 | 0.29 | 4.37 | 0.63 | 3.14 | 7,656 |
| 2016 | 42.43 | 4.20 | 0.29 | 4.50 | 0.65 | 3.20 | 7,623 |
| Average | | | | | | | **7,860** |




The average of the NP-15 and SP-15 market heat rates for 2014 to 2016 shown above is 7,322 Btu/kWh, or within 1% of the 2014-2016 overall average heat rate of 7,373 Btu/kWh indicated by the CEC in Table 1 of its fuel displacement report.[20] This indicates the essential accuracy of the CEC's relatively simple, straightforward method.

Market data also allows one to distinguish locational differences in fuel displacement, particularly between northern and southern California, and to assess the impacts of marginal line losses on the CAISO high-voltage transmission system. With respect to locational differences, in recent years market heat rates have been significantly higher in the southern part of the state as a result of the outage and subsequent closure, beginning in 2012, of the San Onofre Nuclear Generation Station (SONGS). Thus, market heat rates, as shown in the above tables and figure, are markedly higher in southern California than in northern California.

[20] This is based on a load-following heat rate of 7,295 Btu/kWh for 97.5% of annual energy displaced, and 10,419 Btu/kWh for 2.5% of annual energy displaced.

The NP-15 and SP-15 markets are generation "trade hubs" that do not include the line loss and congestion costs of moving power from these hubs to the lower-voltage subtransmission and distribution systems run by the California utilities, and ultimately to end-use customers. However, we note that the CAISO's nodal day-ahead market includes not just the NP-15 and SP-15 trade hubs, which are aggregated prices across generation-related nodes on the CAISO system, but also prices for the load aggregation points (DLAPs) for each utility, which are aggregations of nodes associated with where power leaves the CAISO system to serve load. Thus, by looking at the difference between the day-ahead market prices at the utility DLAPs and at the NP-15 or SP-15 trade hubs, one can calculate the difference in the market value of power at each location. This Locational Marginal Price (LMP) differential includes both the value of transmission line losses between the DLAP and the generation trade hub and the value of congestion to the extent the transmission path between the two "virtual" locations is constrained. As an example, we note that in the CAISO day-ahead market, the PG&E DLAP price has been higher than the NP-15 market price by about $1.80 per MWh. This means that the 2013-2016 MHR at the PG&E DLAP point would be about 5% higher than at the NP-15 trade hub (i.e. 7,330 Btu per kWh at the PG&E DLAP *versus* 7,011 Btu per kWh at the NP-15 trade hub). It is also necessary to add marginal subtransmission and distribution loss adjustments from the CAISO DLAPs to the ultimate electric end user, in order to bring the methodology into line with the onsite-equivalent heat rate that the CEC calculates.

PG&E's 2014 General Rate Case (GRC) indicated cumulative loss adjustments, from the generation bus bar, equal to 1.0200 at the high-voltage transmission level, 1.0360 at the low-voltage transmission level, 1.0555 at the primary distribution level, and 1.1077 at the secondary distribution level. [21] This implies 1.6%, 3.5%, and 8.6% line loss adjustments, respectively, for subtransmission, primary and secondary distribution levels. Thus, the 7,330 Btu/kWh MHR at the PG&E DLAP would be adjusted to 7,445 Btu/kWh at the sub-transmission level, 7,585 Btu/kWh at the primary distribution level, and 7,960 Btu/kWh at the

[21] We express the line loss adjustment as a price adjustment, i.e. 1/(1-Percent Loss). See Table 2-4 of PG&E's testimony in A. 13-04-012.

secondary distribution level on the PG&E system. We note that 7,960 Btu/kWh is within 0.5% of the onsite-equivalent heat rate estimate from the CEC's Table 1.[22] Similarly, the SCE DLAP prices and line loss factors, or the SDG&E DLAPs and line loss factors, could be used to determine subtransmission and distribution level values for the SCE and SDG&E systems. For example, SCE's 2012 GRC indicated annual energy loss factors equal to 1.07993 for secondary, 1.05612 for primary, 1.02718 for subtransmission, and 1.01691 for transmission voltage levels.[23] Thus, the cumulative line loss price adjustments from the transmission level to lower voltage levels would equal 1.1% for the sub-transmission level, 4.2% for the primary distribution level, and 6.8% for the secondary distribution level. Last, we note that the E3 Net Metering Evaluation, completed in October 2013, also contains primary and secondary voltage line loss factors for PG&E, SCE, and SDG&E, which are presented by time-of-use period.[24]

To be clear, the average and market heat rates estimated above are just a component of, and should be view as the starting point for, the complete incremental system heat rate that should be used in estimating fuel displacement. There are also a number of other considerations that must be factored in, such as the above-referenced large block of existing CHP resources in California. Thus, CHP power displaces a significant amount of gas-fired generation which is less efficient than the marginal resource, and the ultimate heat rate value for fuel displaced by CHP exceeds the market heat rate calculations set forth above. To develop an accurate approximation of the system heat rate, these and other calculation adjustments (such as regional differences) will needed to be take into consideration.

[22] Again, assuming 97.5% load following, and 2.5% peaking heat rates.
[23] See SCE's MCCR.xls spreadsheet workpapers in A. 11-06-007, at cells Q80 to Q83 of the input tab.
[24] See Table 4 and 5 of Appendix C to the "California Net Energy Metering Ratepayer Impacts Evaluation" (October 2013) at http://www.cpuc.ca.gov/NR/rdonlyres/C311FE8F-C262-45EE-9CD1-020556C41457/0/NEMReportWithAppendices.pdf .

## C. CONCLUSION

The CCC commends the CEC for convening the July 14 workshop, and posing these important follow-up questions. We consider this an important first step toward the commitment ARB made in the First Update, "ARB is committed to working with the CPUC, CEC, and CAISO to assess existing barriers to expanding the installation of CHP systems and propose solutions that help achieve climate goals."[25] The CCC encourages the agencies to build upon this work by the CEC, and cannot emphasize enough that the time to act is now. Existing efficient CHP is at risk and will shut down unless the state intervenes by providing a clear signal to the market that this is a valued resource with a place in California's future. Many of the companies with existing installations would be at the forefront of new development, if the economic and regulatory environments were favorable.

The CCC appreciates the opportunity to present these comments.

Respectfully submitted,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On behalf of the
**CALIFORNIA COGENERATION COUNCIL**

August 18, 2014

[25] CARB First Update to the Climate Change Scoping Plan, May 2014, at page 42.: http://www.arb.ca.gov/cc/scopingplan/document/updatedscopingplan2013.htm

# Attachment 1

Schedule CGDL-CRS Sheet 5

CUSTOMER GENERATION DEPARTING LOAD COST RESPONSIBILITY SURCHARGE

(Continued)

RATES (Continued)

Customer Generation
Departing Load
Summary of Applicability and Exceptions

**Customer Generation Departing Load Exemptions**

**(Exemptions are cumulative for each applicable generation type)**

| Item # | Generator Type | Generator Size | DWR-Bond | PCIA-URG | PCIA-DWR | CTC | Statewide CAPs* |
|---|---|---|---|---|---|---|---|
| 1 | **if NEM Eligible (Solar, Wind, Biogas, Fuel Cell)** | ≤ 1 MW | Excepted | Excepted | Excepted | Excepted | **3000 MW** |
| 2 | **CSI / SGIP Eligible (only 1MW is exempt)** | ≤ 5MW;Exempt up to 1MW | 1MW Excepted | 1MW Excepted | 1MW Excepted | 1MW Excepted | **3000 MW** |
| 3 | **Biogas Digester, (PUC 2827.9)** | >1MW, ≤ 10 MW | Exempt | Exempt | Exempt | Exempt | **3000 MW** |
| 4 | **Grndfath'd DL that became operl on or b4 1/1/03** | No Constraint | Applicable | Excepted | Excepted | Applicable | **None** |
| 5 | **Ultra-Clean & Low Emission (PUC 353.2)** | >1MW | Applicable | Excepted | Excepted | Applicable | **3000 MW** |
| 6 | **Meet BACT stds set by AQMD &/or CARB** | No Constraint | Applicable | Excepted | Excepted | Applicable | **1500 MW** |
| 7 | **DLthat began to recv svc from CG on/or b4 2/1/01** | No Constraint | Exempt | Exempt | Exempt | Applicable | **None** |
| 8 | **UC/CSU Sys ID'd in SectionV.B.4 of D.03-04-030** | No Constraint | Applicable | Excepted | Excepted | Applicable | **165 MW** |
| 9 | **CoGen PUC372 &/or374 &PrelmStmt PrtWSec4** | No Constraint | Applicable | Applicable | Applicable | Exempt | **3000 MW** |
| 10 | **Continuous DA = DA ≤ 2/1/01 thru > 9/20/01** | No Constraint | Exempt | Exempt | Exempt | Applicable | **None** |
| 11 | **New OrIncr'mtlDL-MstPassPhysTest,PrelStW4a** | No Constraint | Exempt | Exempt | Exempt | Exempt | |
| 12 | **CoGen PUC372 &/or374 &PrelmStmt PrtWSec4** | No Constraint | Applicable | Applicable | Applicable | Exempt | |
| 13 | **DL Servd by another entity who charges PPPC** | No Constraint | | | (Exemptions are cumulative for each applicable generation type) | Applicable | |

*After State-wide Caps have been reached CRS charges apply. See State's Website: http://www.energy.ca.gov/exit_fees/megawatt_cap.html

(Continued)