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October 22, 2012

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California Energy Commission
Dockets Office, MS-4
Re: Docket No. 12-IEP-1D
1516 Ninth Street
Sacramento, CA 95814-5512

Re: <u>2012 IEPR: Comments of Pacific Gas and Electric Company on the Staff Paper: "A New Generation of Combined Heat and Power: Policy Planning for 2030"</u>

I. INTRODUCTION

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide comments on the California Energy Commission (CEC) Staff Paper entitled "A New Generation of Combined Heat and Power: Policy Planning for 2030," (hereinafter referred to as the Staff Paper).

The Staff Paper makes several long-term planning recommendations, many of which can be supported by PG&E. However, the Staff Paper also contains numerous financial and regulatory recommendations that would only serve to increase customer costs and shift costs from one customer class to another without any assured reliability or greenhouse gas (GHG) reduction benefits. PG&E is supportive of clean, cost-effective combined heat and power (CHP) that enhances electric system reliability. We do not support recommendations that will increase costs to customers while subsidizing inflexible, inefficient generators that increase greenhouse gas emissions.

PG&E's comments address numerous issues with the Staff Report. In summary, these issues include:

- PG&E does not support a CHP portfolio standard because it is unclear at this time what the true obstacles to additional CHP deployment are. PG&E is supportive of a CHP educational forum that could help educate building owners about CHP benefits.
- The Renewable Portfolio Standard should not be amended as proposed in the Staff Paper because it would unduly increase customer costs and could create new system reliability issues.
- CHP already enjoys numerous exemptions from existing demand, standby, and departing load charges and additional exemptions should not be granted. Furthermore, additional clarity is needed in the Staff Paper to better reflect the exemptions currently provided to CHP.

- Numerous factual and technical clarifications are needed.

PG&E also provides recommendations on how CHP efficiency reporting should be improved through revisions to the Quarterly Fuels and Energy Report–Form 1304.

II. PG&E DOES NOT SUPPORT A CHP PORTFOLIO STANDARD

PG&E is opposed to a CHP portfolio standard because clean, cost-effective CHP should be appropriately recognized and rewarded in the cap-and-trade program and carve outs and set-asides only serve to unduly increase customer costs. Numerous initiatives to support CHP have already been passed or authorized, and PG&E's focus today is on successfully implementing these policies. As the Staff Paper correctly notes, PG&E's CHP Request for Offer (RFO) is currently in process, the AB 1613 CHP power purchase agreements (PPA) are now available, and the SGIP program continues to be implemented. Sufficient time should be allowed to study these existing policies, and to gather "lessons learned" before layering on more initiatives that might actually increase uncertainty related to CHP development and operation. A rush to create a CHP portfolio standard, without a robust, balanced analysis of what the true barriers to CHP are and without the experience gained from current CHP procurement and programs, is premature and runs the risk of poor policy outcomes. PG&E recommends that this action item be deleted from the Staff Report.

III. PG&E SUPPORTS CEC EDUCATIONAL FORUMS ON CHP ISSUES

There are two critical areas where customer education about the benefits of CHP can increase market participation. The first is in the area of market research, which has shown that up to half of nonresidential customers have a high payback threshold for capital investment outside their core business (e.g., they want to recover the investment over a four year period, even though the asset may last 30 years). This means that the hurdle for these customers to invest in CHP is high, even when it makes sound economic sense. In addition, few nonresidential customers understand the benefits of CHP, and fewer want to acquire the expertise necessary to maintain and operate a CHP unit. In both of these areas, increased knowledge can lead to increased CHP penetration, especially for customers who own commercial office buildings. The most recent ICF study identified a significant CHP market potential in the area of cooling in office buildings. Increased knowledge of the advantages of CHP that serves cooling load could open this market to expanded development. We support the CEC providing this information. However, as noted in the energy efficiency arena, the ownership, management, operation and use of buildings are often not within the purview of single counterparty, but rather multiple counterparties, each with different motivations and incentives. This creates additional challenges in reaching decision makers who can make the decision to invest in CHP.

IV. THE RENEWABLE PORTFOLIO STANDARD SHOULD NOT BE AMENDED

The Staff Paper recommends that the Legislature amend the RPS to either exempt electricity purchased from efficient CHP resources or include all electricity generated from CHP resources in the calculation of total retail sales.[1] This proposal appears to be based on the conclusion from ICF's study 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 [RPS] percentage targets. Therefore, with the Renewable Portfolio Standard in place, the avoided utility emissions are only 67 percent of the avoided emissions of the marginal fossil fuel electric system.*"[2]

The Staff Paper's explanation of the issue is unclear and the proposed solutions require substantial changes to the RPS. PG&E opposes such changes for a variety of reasons. First, the current RPS represents a complex balance of various stakeholder needs and concerns. Changing one provision of the law will upset this delicate balance and potentially lead to other amendments, creating great regulatory uncertainty.

Second, if the proposed change leads to increased RPS stringency, this could cost customers hundreds of millions of dollars per year. Significant costs from the existing RPS program are now beginning to impact electric rates.

Furthermore, such a change could exacerbate system operations reliability issues and by introducing a mix of inflexible and intermittent generation into the system, increasing the need for more operationally flexible resources to integrate them, and increasing the incidence of over-generation. The recommendation fails to consider these issues and should be rejected.

Creating a program to drive GHG reductions from CHP that is independent from the program driving GHG reductions from renewables does not recognize the requirements inherent in operating an electric system. One program cannot be looked at in isolation from others; to do so would undermine the state's integrated resource planning efforts and create numerous operational complications.

In summary, further limitations to procurement flexibility will only increase customer costs unduly; instead the focus should be on how best to create a procurement framework that provides the flexibility to choose across all resources that reduce GHG emissions and allows for the selection of the resource that most cost-effectively accomplishes that goal. Such technology-neutral, attribute-based, competitive procurement could allow the state to maintain a reliable and affordable electricity portfolio while improving GHG performance.

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1 Staff Paper, pg. 52
2 2012 ICF Analysis, pg. 9

V. CHP SHOULD NOT BE GIVEN ANY ADDITIONAL EXEMPTIONS FROM EXISTING DEMAND, STANDBY, AND DEPARTING LOAD CHARGES

PG&E agrees that demand charges and standby charges should be periodically reviewed by the CPUC during utility general rate case proceedings. The purpose of this review should be to ensure a continued nexus between customer charges and cost of service. However, PG&E does not support modification of rates for specific groups absent an appropriate cost-of-service analysis. In particular, PG&E cannot support modification of demand charges, standby charges and non-bypassable charges (NBC) for CHP customers without analysis that can support the modification. Put simply, lowering charges for one set of customers raises them for other customers. Accordingly, PG&E recommends that the proposed action item to eliminate NBCs or standby charges for CHP be eliminated or, in the alternative, it should be modified to indicate that the CPUC should consider whether any modification to current policies is appropriate in the next General Rate Case (GRC).

A. Policy Reasons for Existing Demand, Standby, and Departing Load Charges

Procurement-related NBCs were created by the Legislature and CPUC to protect bundled customers and it goes against legislative intent to arbitrarily exempt customers who install CHP. The Legislature (and the CPUC) historically established these NBCs because of electric industry restructuring (e.g., Nuclear Decommissioning charge, the Competition Transition Charge (CTC) to recover the above-market costs of Qualifying Facilities (including CHP)) and as a result of the failure of electric restructuring in California (e.g., Power Charge Indifference Adjustment (PCIA), Department of Water Resources (DWR) Bond Charge).

Other NBCs have been established to implement policies that were imposed on investor-owned utilities, but not on other load-serving entities (i.e., energy service providers, publicly-owned utilities, community choice aggregators). Again the decision to make certain charges non-bypassable is motivated by a decision to protect remaining bundled customers. Exemptions from departing load charges do not reduce the cost of the service provided, whether through a PPA or an energy efficiency program. The costs of the service provided are simply shifted to bundled customers, compromising the purpose of the non-bypassable charge.

Ironically, the costs of many of the existing price supports that are currently provided to CHP are recovered through NBCs paid by all customers other than those receiving the price support. Specifically, CHP benefits from either above-market costs recovered through the CTC defined in the initial restructuring legislation, as well as through the CHP-Cost Allocation Mechanism (CAM) charge created by the QF/CHP Settlement.

In addition customers installing efficient CHP also enjoy exemptions from some NBCs. CHP facilities up to 5 MW that are eligible for the Self-Generation Incentive Program (SGIP) program are exempt from the DWR Bond Charge, the PCIA, the Energy Cost Recovery Amount (ECRA), and the Competition Transition Charge for the first MW of generation. They are also exempt from the New System Generation Charge (NSGC), which was established by the CPUC as a non-bypassable charge to implement the CHP CAM from the QF/CHP Settlement agreement.

If the CHP facility is over 1 MW, but meets the definition of "ultra-clean and low emissions" in California Public Utilities (CPU) Code Section 353.2, the departed load is responsible for the DWR Bond charge, but is exempt from the PCIA, ECRA, and NSGC. Smaller CHP projects that are receiving financial support through the SGIP may avoid contributing to the cost of this program if they are on rate schedules where they can avoid paying the distribution costs by offsetting the energy and demand charges.

In addition, all CHPs, regardless of size, are eligible for discounted gas rates. They are also exempt from paying for any of the above-market costs of new generation (procurement subsequent to January 1, 2003, including any costs of procuring renewables to meet the state's renewable targets). These costs that CHP avoids are shifted to other PG&E retail customers.

The NBCs and other charges from which the Staff suggests CHP avoid responsibility are all reflections of real costs. Standby service is of value to the customer with CHP and reflects the fact the grid stands ready to meet the customer's load in case of planned or unplanned failure of the CHP. Demand charges recover at least some of the sunk costs that the utility incurs to provide grid support for the customer's real demand. Public purpose program charges support energy efficiency programs that are at the top of the loading order. All of these costs are incurred whether or not the CHP customer contributes their share. There is simply no justification for exempting CHP customers beyond the exemptions they already enjoy.

B. Factual Corrections are Needed to Better Characterize the Charges Paid by CHP

The staff paper appears to outline most of the NBCs that apply to departing load generally, but the discussion does not describe which of these NBCs are actually applicable to CHP facilities.[3] As discussed above, most CHP facilities are exempt from Ongoing CTC, PCIA, NSGC and ECRA or regulatory asset charges. In addition, the majority of the efficient CHP facilities are further exempted from DWRB charges. Thus, it is most common that CHP facilities pay only ND) and PPP charges. The staff paper makes no mention of the NBC exemptions provided to the majority of CHP departing load. Instead, the staff paper leaves the impression that all of the charges apply to all CHP generation all of the time. This is an incomplete and potentially misleading description of the NBCs applicable to CHP generation.

The staff paper also states that, "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)".[4] The range of the 'current departing load charges' quoted in

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3 Staff Paper, pg. 44
4 Staff Paper, pg. 45

the staff paper can be misleading due to several factors. PG&E AG-5 customers[5] (large agricultural end-use customers) tariff schedule is not a representative rate class to use for CHP facilities. CHP facilities are generally located with a commercial or industrial application and thus tariff schedules E-19[6] and E-20[7] are the most applicable rate schedules.[8] PG&E reiterates that the NBC exemptions provided to CHP technology generators should be reflected and the staff paper should present a more balanced view of the charges applicable (see Table 1).

Table 1. Illustrative NBCs paid and avoided by CHP

Non-bypassable Charge (NBC) Name	**Current Rate for a Customer on the E-20 Tariff [1]**
Most CHP is Exempt from:	
Competition Transition Charge	0.67 $/MWh
New System Generation Charge	0.80 $/MWh
Power Charge Indifference Adjustment	5.41 $/MWh - 2012 Vintage
Energy Cost Recovery Amount	5.04 $/MWh
Total NBC exempted	**11.92 $/MWh**
Most CHP Pays:	
Department of Water Resources Bond	5.13 $/MWh
Nuclear Decommissioning	0.550 $/MWh
Public Purpose Program	11.88 $/MWh
Total NBC paid	**12.43 - 17.56 $/MWh**
[1] **See: http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-20.pdf**	

5 http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_AG-5.pdf
6 http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-19.pdf
7 http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-20.pdf
8 We note that the ICF report uses the E-20 tariff as an example (see Table 24 of the ICF analysis)

VI. THE STAFF PAPER'S PURPOSE IS UNCLEAR AND A MORE COMPREHENSIVE ANALYTICAL FRAMEWORK IS NEEDED

As California continues towards an ever-cleaner energy future, a critical issue is to understand under which circumstances CHP will reduce GHG emissions. PG&E supports efficient CHP that provides a cost-effective and reliable source of electricity to our customers and helps to reduce greenhouse gas emissions statewide. However, the Staff Paper fundamentally fails to appropriately explore all three dimensions of "good CHP": low environmental impact, affordability for customers, and positive impacts on grid performance and system reliability. Accordingly, PG&E recommends that the Staff Report's action items to address financial and regulatory barriers be excluded from the 2012 Integrated Energy Policy Report (IEPR) Update.

Many of these issues were explored in an analysis performed by ICF[9] for the CEC and discussed in a February 2012 workshop. However, PG&E is perplexed about how the CEC staff reached the conclusions in the Staff Paper and developed the associated action items; there is nothing in the record to support many of the conclusions.

First, the Staff Paper provides only a difficult-to-follow interpretation of ICF's assessment of how CHP will reduce GHG emissions. It does not address the CEC's reporting requirements. It does not ensure its policy recommendations to promote significant amounts of additional CHP will create GHG emissions reductions. As PG&E has consistently articulated, not all CHP is created equal. It is important that the State's policy emphasize the preference for efficient CHP that emits fewer greenhouse gases than separate heat and power. The CEC can ensure that this is the case by amending their CHP reporting rules and closely monitoring the actual emission performance of CHP units.

Second, the Staff Paper highlights but lacks any recommendations linking the reasonableness of the State's CHP goals' impact on grid reliability or customer costs. The Staff Paper provides only a cursory paragraph that explains that "maximizing energy from renewable resources has shifted the way other resources are valued" and that, without changes, "CHP projects will have limited economic incentives to participate and be integrated into the dynamic grid of the future".[10] There is minimal discussion of system operations, overgeneration, or dispatchability, and there is no information provided about the types of CHP technologies that can help integrate intermittent renewable resources (i.e., fast ramping). Furthermore, there are no customer cost analyses for the proposed actions items on financial and regulatory barriers. For example, there is no cost estimate associated with the various GHG, RPS, financial assistance, or associated action items. Californians should be fully informed about the cost associated with various public policy proposals and we should not pursue action items that would

[9] *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*, ICF for the California Energy Commission, June 2012.

[10] Staff Paper, pg. 3

unduly increase customer costs, particularly when they may not reduce GHG emissions or improve support for grid reliability.

CHP's place in the broader framework of California's energy policies, and whether CHP will help achieve California's energy and environmental goals, is deserving of additional study.[11] As noted above, a more robust analysis prior to policymaking is especially critical because CHP, unlike renewable generation, has the potential to increase GHG emissions if deployed and operated in an inefficient way. PG&E is committed to working with stakeholders to develop appropriate policies for clean, cost-effective CHP that can support a clean energy future. Recommendations for an expanded CHP portfolio standard need to be explored in greater depth to ensure that the programs will actually achieve the desired public policy goals.

VII. THE "ACTIONABLE ITEMS" IN THE STAFF PAPER LACK SUFFICIENT SUPPORTING ANALYSIS

A. Recommendations to Pursue Utility-Owned CHP are Untimely

The Staff Paper recommends that the CPUC allow a larger percentage of new utility-owned or co-owned CHP generation to count toward the CHP Program targets created by the Qualifying Facility ("QF")/CHP Settlement Agreement.[12] PG&E is focused on providing safe, reliable, and affordable electric service to its customers and it is not actively pursuing development of utility-owned CHP at this time. Accordingly, PG&E sees little value in this action item and recommends that it be deleted.

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[11] Recent studies, included those funded by the CEC and ARB, of California's achievement of the year-2050 GHG emissions goals view CHP as providing a transitional role. For examples see:

"California's Energy Future: The View to 2050". California Council on Science and Technology (2011) http://www.ccst.us/publications/2011/2011energy.pdf

"California's Energy Future: Portraits of Energy Systems for Meeting Greenhouse Gas Reduction Targets". California Council on Science and Technology (2012) http://www.ccst.us/publications/2012/2012ghg.pdf

"High-resolution modeling of the western North American power system demonstrates low-cost and low-carbon futures" Kammen et al (2012) http://www.energy.ca.gov/2012_energypolicy/documents/2012-04-12_workshop/presentations/03b_Nelson-Kammen-UC_Berkeley_SWITCH-EnergyPolicy-2012.pdf

"The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity." Williams et al (2011) http://www.sciencemag.org/content/335/6064/53

"Meeting California's Long-Term Greenhouse Gas Reduction Goals." Energy and Environmental Economics, Inc. http://ethree.com/documents/GHG6.10/CA_2050_GHG_Goals.pdf.

[12] Staff Paper, pg. 52

Before utility ownership of CHP is considered, more evaluation is needed as to what system reliability or other customer benefits utility CHP ownership would offer. Utility ownership of CHP units is challenging because the most efficient CHP units would likely be located on a customer's property, as close as possible to the thermal load. To achieve GHG emissions reductions, it is also critical that the CHP operation be well-matched to the thermal load. This means that operation of the unit would likely be controlled by the thermal host. It is difficult to see how utility ownership would enhance the potential for efficient, low-cost CHP. It is possible that under utility control CHP could better contribute to electric system flexibility, however any trade-offs with environmental performance and costs are left unexplored in the Staff Paper.

B. Cap-and-Trade is Likely to Incentivize Efficient CHP

The Staff Paper portrays cap-and-trade implementation as "the greatest uncertainty facing CHP developers."[13] PG&E agrees that the impact of cap-and-trade on incentives for CHP, as well as other resources, is still uncertain, but disagrees about both the degree of uncertainty, and with the Staff Paper's conclusion that "in its current form, a cap-and-trade system is a disincentive to invest in clean, efficient CHP."[14] In fact, cap-and-trade—and more importantly Assembly Bill (AB) 32 as a whole—is likely to provide a significant positive incentive for efficient CHP (see Table 2).

Efficient CHP that exports power to the electric grid is clearly incentivized by cap-and-trade. Once the cap-and-trade program begins, grid-delivered electricity will receive additional revenues from the ability to obtain higher electric prices in wholesale electricity markets that now reflect GHG prices. Efficient electricity-exporting CHP generators are likely to see an increase in operating margins and inefficient exporting CHP will see a decrease in operating margins. These higher wholesale market prices and operating margins provide a direct incentive for the installation of efficient new exporting CHP and for existing exporting CHP to improve efficiency. Less efficient units will, appropriately, not receive the same financial benefits as cleaner, more efficient units, given they emit more greenhouse gas emissions than the cleaner units.

Table 2. AB 32 Incentives for Efficient CHP

Use of CHP Electricity	*AB 32 Incentive for Efficient CHP*
Electricity Exported to the Grid	**Positive**. Additional revenue from wholesale sale of electricity will be greater than any incremental AB 32 program costs for efficient CHP.
Electricity Used On-Site*	**Potentially positive**. If AB 32 program costs embedded in retail rates reflect an appropriate carbon price signal, avoided carbon costs in electricity purchases will be greater

13 Staff Paper, pg. 41
14 Staff Paper, pg. 4

	than direct carbon costs for new efficient CHP. **Potentially negative.** If AB 32 program costs embedded in retail rates do not reflect an appropriate GHG price signal.
* Cap-and-trade incentives for CHP producing electricity for use on-site will be affected by forthcoming CPUC decisions around return of utility auction proceeds under R.11-03-012.	

The incentive structure associated with CHP that displaces retail electricity purchases (by creating power for on-site use) is more complex. The impact of cap-and-trade on retail electricity prices is dependent on how utilities are permitted to use the allowance value given to them by the Air Resources Board (ARB).

ARB considers cap-and-trade as part of a suite of AB 32 measures. As ARB analyzed this suite of measures during its cap-and-trade rulemaking, ARB's goal was to create an appropriate GHG price signal to incentivize GHG reductions across the California economy. ARB and the CPUC correctly recognize that the Renewable Portfolio Standard (RPS) and other "complementary" policies will impact the GHG price signal embedded in the price of electricity. The CPUC is actively considering how to best address this interaction effect through the use of utility allowances in R.11-03-012. The results of this stakeholder process should not be prejudged by CEC staff. Accordingly, PG&E recommends that this action item be deleted or modified to recommend that CHP's incentives from cap-and-trade and AB 32 be re-evaluated once the CPUC has completed its work on this issue.[15]

C. Interconnection Rules Revisions Are Already Under Consideration in Other Appropriate Venues

The Staff Paper recommends easing the interconnection procedures for facilities that expand their generation capabilities, without providing any justification for such special provisions. Interconnecting an expanding facility has similar impacts on the grid system as that of interconnecting a new generator. It is important to match the interconnecting facility rating and power quality with the grid system needs to maintain voltage and frequency stability. The grid interconnection procedures such as CPUC Rule 21, FERC Wholesale Distribution Access Tariff (WDAT) and CAISO Generator Interconnection Procedures, ensure that the system reliability in maintained while interconnecting a new or expanding facility.

15 PG&E is concerned by the limitations placed on use of allowance value by Assembly Bill 1018. We believe that prohibiting AB 32 allowance revenue return to larger commercial customers and (industrial customers not deemed to be "emissions-intensive trade-exposed") could unfairly increase rates for these customers. However, from a CHP incentive perspective, this rate increase would create an increased incentive to undertake CHP projects that offset purchased power.

The Staff Paper outlines the regulatory proceedings updating the current interconnection procedures but fails to connect these proceedings and draw the conclusion that revisions are under considerations in the appropriate venues. The CPUC and FERC interconnection procedures provide a level playing field for all distributed generation providers by laying out clear and transparent protocols for interconnection. The WDAT procedure was recently revised[16] and the results of newly approved cluster study process should be thoroughly analyzed before providing any further policy recommendations.

Lastly, the revisions to the CPUC Rule 21 process are ongoing. The CPUC approved the "Phase One" Rule 21 Settlement under Decision 12-09-018[17] on September 13, 2012. The CPUC is expediting further revisions to the Rule 21 process in Phase 2[18] of Rulemaking 11-09-011 proceedings. PG&E supports ongoing efforts by the CPUC and various stakeholder groups to improve the process while emphasizing that "carving out" a specific exemption or preferential treatment for CHP or any other resource type could adversely affect safety, service reliability and affordability.

D. PG&E Supports Additional CEC Analysis of Metering Requirements

In general, PG&E supports an effort by the CEC to study various metering requirements across programs and agencies and to propose any potential ways to consolidate the requirements. The Energy Commission is uniquely suited to explore simplification of metering requirements that could serve to ensure continued production of quality data while lowering costs for customers who choose to meet part of their energy needs through self-generation. However, accurate metering of CHP electric and thermal output and is necessary to demonstrate environmental performance relative to separate heat and power. In many cases these metering requirements cannot be compromised without risking the primary underlying policy driver for CHP—greenhouse gas emissions reduction.

E. The use of CEC EPIC funds for CHP Research is Reasonable

PG&E agrees that the use of some EPIC funds for CHP work is appropriate, provided it is not duplicative of other projects. PG&E suggests that the requirements being met by the metering should establish the parameters of any such research. In particular, the Energy Commission should include:

16 The effective date of the amended Wholesale Distribution Tariff is March 3, 2011, PG&E's revised WDT online at http://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/tariffs/PGE_Wholesale_Distribution_Tariff.pdf

17 The CPUC Rule 21 Settlement Decision 12-09-018, online at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M028/K168/28168335.PDF

18 CPUC Rulemaking 11-09-011 Phase 2 memo release on September 25th, 2012 – online at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M028/K946/28946652.PDF

- Continued support for revenue grade metering for any meters that support bill calculations. This includes not only the customer's SmartMeter, but any NGOM required for participation in, for example, a NEMMT tariff, a FIT, etc.
- Metering/monitoring that determines thermal use of CHP installations must be accurately measured with "used" (not "useful") thermal output.

Metering/monitoring that determines thermal use of CHP installations must be capable of supporting GHG emissions calculations used to ensure compliance with FIT or other requirements.

F. CHP Should Remain Ineligible for Net-Energy Metering

PG&E cannot support the further expansion of net metering to all CHP facilities, for a number of reasons. First, as the CPUC has found, net metering creates a cross-subsidy enjoyed by customers who can choose self-generation as a way to reduce their energy costs (often customers fortunate enough to have available capital to invest) but that subsidy is paid for by customers who do not have these choices. Net metering was originally established to provide a subsidy for what was then a nascent solar industry in California. The solar industry is no longer in its infancy and, with the exception of fuel cell CHP, CHP is dominated by mature technologies. CHP can provide a cost-effective energy choice for customers whenever there is a good match for the customer's thermal needs. Where there is not a good match, it is possible, perhaps likely, that a net increase in GHG emissions as a result of the CHP will result, and it should not be subsidized. Customers installing efficient CHP reduce their bills whenever they are offsetting their own use. In addition, if they qualify for AB 1613 FIT, they receive generous compensation for any exports under this tariff.

Second, as noted, PG&E cannot support expansion of NEM to all CHP facilities. It is important to note that NEM for CHP using renewable fuel became available in 2012, regardless of whether the CHP unit is a fuel cell or other technology. This benefit became available in 2012 and to date, PG&E has received no requests from any CHP facilities to take advantage of the net metering program. PG&E is working to identify customers who may be CHP and who may be using renewable fuel and, should such customers be identified, PG&E will contact those customers to see if they would prefer NEM over their current tariff arrangement (such as NEMFC).

In conclusion, with respect to CHP, there is no basis to conclude that CHP needs the magnitude of the subsidy offered by NEM or that progress toward critical policy goals will be achieved as a result of these subsidies. CHP technologies are generally well understood and well established. There is no basis to conclude that efficient CHP requires a NEM subsidy. Therefore, prior to any changes in NEM rules, standby rates, or non-bypassable charges, regulators must first clearly understand the magnitude of the cost shifts and determine whether remaining customers should shoulder this additional burden.

G. State Agencies, Including the Air Resources Board, Should Continue to Monitor the Impacts of Existing CHP Policy

The Staff Paper recommends that the "Energy Commission and the CPUC should continue to track, analyze, and report to the Governor and Legislature on the progress of the *QF Settlement*, AB 1613, and other state programs designed to encourage new CHP".[19] PG&E supports such continued analysis, especially in the areas of CHP efficiency and GHG performance. PG&E suggests that the ARB be included in any CPUC and CEC discussions, as they are statutorily directed to serve as the lead agency on questions of GHG emission reductions under both AB 32 and AB 1613.

H. The CEC Should Revisit its Technical Assessment of CHP as the Current Study is Overly Optimistic

As indicated in PG&E's prior comments, the 2012 ICF study still overstates the potential for efficient CHP in California.[20] While ICF's current CHP estimates are lower—and more realistic—than those presented in 2009, ICF's study continues to overestimate both the technical potential and likely market penetration for greenhouse gas emissions reducing and cost-effective CHP in California, particularly for existing, small customers. PG&E is concerned that, despite comments from numerous parties, ICF's estimates remain unchanged in the final report. It may be worthwhile to hold additional stakeholder discussions prior to updating or finalizing subsequent CHP potential reports.

VIII. THE STAFF PAPER SHOULD BE CORRECTED FOR FACTUAL INACCURACIES

A. CHP has an Export Market for Excess Generation

The Staff Paper states that "the lack of an export market for excess generation" is a barrier to CHP development.[21] This directly contradicts the finding of the Federal Energy Regulatory Commission (FERC). In the order terminating California IOUs' obligation to purchase power from large QF facilities, FERC found that CHP in California has nondiscriminatory access to wholesale energy markets.[22] This finding was one of the conditions precedent to the QF/CHP Settlement.[23]

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19 Staff Paper, pg. 54

20 PG&E Comments filed March 12, 2012.

21 Staff Paper, pg. 50

22 See FERC "Order Granting Application to Terminate Purchase Obligation" (135 FERC ¶ 61,234) issued June 16, 2011 http://www.ferc.gov/whats-new/comm-meet/2011/061611/E-7.pdf

23 See section 16.2.2 of the QF/CHP Settlement Term Sheet available here: http://www.pge.com/includes/docs/pdfs/b2b/energysupply/qualifyingfacilities/settlement/final_term_sheet.pdf

B. QF/CHP Settlement Term Sheet – Misinterpretation of Contract Length Requirement

The Staff Paper incorrectly states that the CHP Settlement requires PPAs for "12 years for new, repowered, and expanded facilities and 7 years for existing facilities".[24] These are maximum values.

C. Inaccurate Characterization of Cap-and-Trade Allowance Allocation

The Staff Paper claims that in cap-and-trade, "new facilities are not eligible for free allocation".[25] This is an incorrect statement. New facilities under ARB's "Energy-Based Allocation Calculation Methodology" would be, "assessed a baseline annual allocation based on expected activity levels as determined by the Executive Officer".[26] Facilities covered by ARB's "Product Output-Based Allocation Calculation Methodology" receive additional allocation as they begin to produce additional output.[27] Finally, allocations to large refineries expand if actual 2013 and 2014 emissions are greater than the assumed baseline emissions (as they might be if a significant new CHP unit was installed).[28] Neither the 2012 ICF Study nor the Staff Paper correctly characterizes these nuances of the ARB allocation scheme.

The Staff Paper also states that, "CHP never clearly fit into a single cap-and-trade category – it overlapped the category designed for boilers and the one designed for electricity generators."[29] PG&E is unaware of any cap-and-trade categories designed for boilers or electricity generators with respect to allowance allocation.

D. Mischaracterization of the Current Regulatory and Policy Environment for Eligible CHP Facilities under Assembly Bill 1613

The CEC staff paper incorrectly portrays the current regulatory and policy environment for the Assembly Bill (AB) 1613 program.[30] The paper specifically outlines two unique case studies of new CHP facilities: Sonoma County and Chevron Cymric. The staff paper misrepresents the actual facts of these two CHP facilities, mischaracterizes these unique situations as being risks AB 1613-eligible generators can generally expect to encounter, and fails to acknowledge the progress made by PG&E to resolve any outstanding issues relating to Sonoma County and Chevron Cymric. These are unique business situations between PG&E and these two parties and it is inappropriate to derive general conclusion for all AB 1613 generators based on these two instances.

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24 Staff Paper, pg. 20
25 Staff Paper, pg. 33
26 Article 5, Title 17, California Code of Regulations ("CCR") §95891(c)(3). Unofficial ARB version here: http://www.arb.ca.gov/cc/capandtrade/september_2012_regulation.pdf
27 CCR §95891(b)
28 CCR §95891(d)(2)(c)
29 Staff Paper, pg. 41
30 Staff Paper, pg. 24-26

Sonoma County CHP facility: In December 2009, the County of Sonoma applied and was granted a reservation under the 2009 SGIP for the installation of a 1,400 kW non-renewable fuel cell. The completed project received a site inspection in January 2011, and an incentive was paid to the County of Sonoma in the amount of $3,000,000.[31] The 2009 SGIP Handbook rules deemed any onsite generator that exported and sold power as ineligible for the program (2009 SGIP Handbook Section 2.2). The CEC staff paper misrepresents these facts as "The 2010 SGIP Handbook does not allow for payment of electricity export".[32] When Sonoma County applied for SGIP funding in 2009, they were well aware of the SGIP eligibility criteria and did not expect payment from exporting excess power to the grid.

The rules regarding export of electricity along with SGIP incentives were revised in the 2011 SGIP Handbook pursuant to the CPUC Decision (D.) 11-09-015. Under the revised rules, CHP facilities like Sonoma County can be eligible both for SGIP funding as well as export of electricity under the AB 1613 program. However, the SGIP incentive structure was also revised from full upfront payment to half upfront payment and half performance based incentives payment (made available to the SGIP facilities at later stages). Taking into consideration the exceptional situation of Sonoma County CHP facility of transitioning between two SGIP guidelines, PG&E filed an advice letter at the California Public Utilities Commission ("CPUC") in July 2012[33]. It requested the CPUC to authorize an exemption for Sonoma County's fuel cell facility to be eligible to execute a new AB 1613 contract under specific circumstances. The CEC staff paper should acknowledge the progress made by PG&E on the unique situation of Sonoma County's CHP facility with respect to eligibility in PG&E's AB 1613 program and should revise the appropriate sections of the case study.

Chevron Cymric CHP facility: The staff paper cites the Cymric case study presented at the workshop by Chevron.[34] The Staff misrepresents PG&E's efforts on this project, including a statement that, "although a separate meter could be installed and the new CHP system could run independently of the existing system and not interfere with that contract, this option has been a nonstarter for PG&E."[35]

PG&E has provided multiple options to Chevron that we believe are consistent with all applicable interconnection requirements, prudent contract management practices and prior CPUC decisions requiring that customers share in any benefits received by generators due to modifications of their facility. It is not appropriate for the Staff Paper to use anecdotal evidence

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31 PG&E Advice 3314-G-A/4073-E-A online at - http://www.pge.com/nots/rates/tariffs/tm2/pdf/GAS_3314-G-A.pdf

32 Staff Paper, pg. 25

33 PG&E Advice 3314-G-A/4073-E-A online at http://www.pge.com/nots/rates/tariffs/tm2/pdf/GAS_3314-G-A.pdf

34 Staff Paper, pg. 26 and 44

35 Staff Paper, pg. 26

from a singular case study as the basis for formulation of state CHP policy, nor is it appropriate to misrepresent PG&E's positions in a public document.

IX. RECOMMENDATIONS FOR IMPROVEMENTS TO THE STAFF REPORT

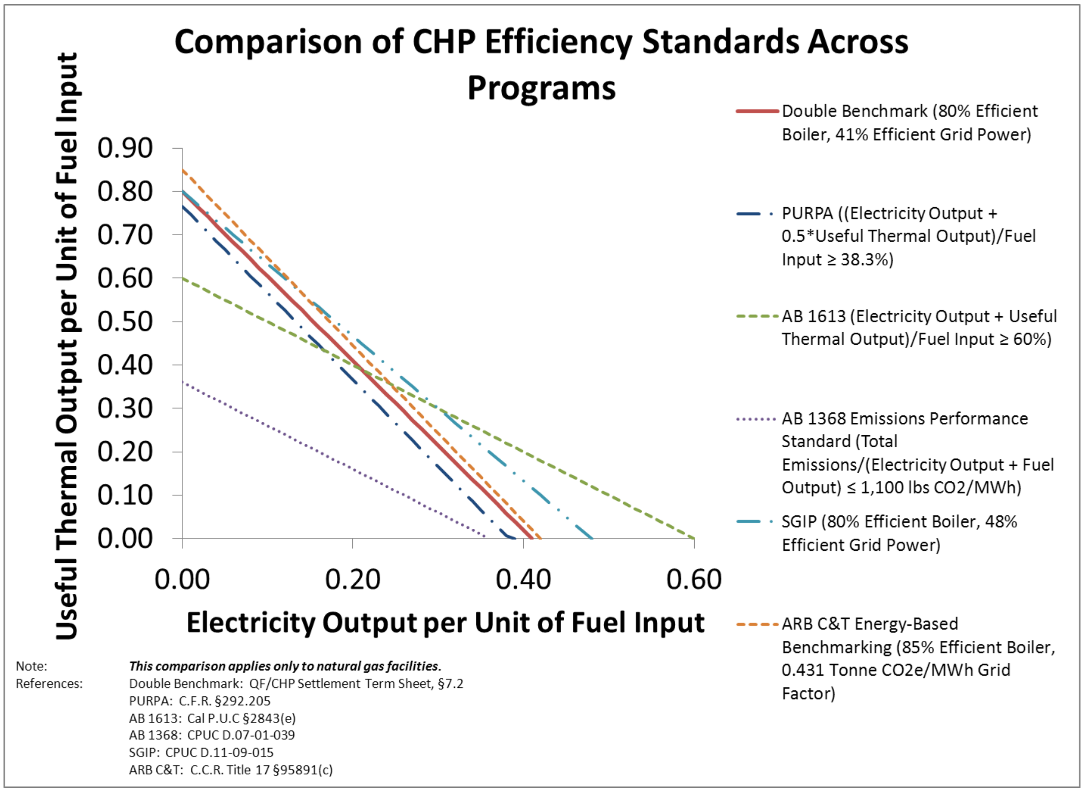
A. The Staff Report Should Recommend Improved CHP Efficiency Reporting Through Revisions to Quarterly Fuels and Energy Report–Form 1304

To inform understanding of efficient CHP potential, the CEC should revisit the reporting guidelines of thermal output reported by CHP facilities in the Energy Commission Quarterly Fuels and Energy Report (QFER) so that generators report better quality information more consistently. Form 1304 reporting should require all CHP facilities to report fuel input, net electrical output, and **used** heat output. All values should be reported in units of million British thermal units (MMBtu). Taken together these three values will provide accurate CHP operating efficiency information. PG&E provided its suggested changes to Form 1304 in its comments submitted on March 12, 2012.

B. The Report Should Include a Comparison of CHP Efficiency Standards Across Programs

A variety of standards exist in California related to CHP efficiency (see Figure 1). These standards should be considered jointly by the CEC, CPUC and ARB. One immediately noticeable item is that, in many cases, the requirements for small CHP facilities (SGIP and AB 1613 with high electrical output) are more stringent than the standards that apply primarily to larger facilities (PURPA efficiency standard and the QF/CHP Settlement double benchmark). It may be helpful to update these standards to provide greater harmonization and to better reflect improvements in performance of separate heat and power production systems that CHP must outperform to reduce GHG emissions.

Figure 1. Comparison of Efficiency Standards across Programs



C. The Report Should Evaluate the Potential for Flexible CHP

Given the expected increase in intermittent renewables, the grid of the future will need to be more responsive and flexible than it is today. Because hourly generation from intermittent resources is difficult to forecast accurately, and is variable due to weather fluctuations, different types of operating flexibility are needed from operationally flexible resources to continuously balance generation and customer demand. These flexible resources have greater value from a resource planning and energy procurement perspective. As currently configured, most CHP power purchase agreements provide very limited operational flexibility. The CEC should explore ways in which CHP could provide flexibility while still achieving GHG reductions.

X. CONCLUSION

PG&E looks forward to continuing discussion of combined heat and power issues in the future IEPR cycles.

Sincerely,

/s/

Valerie J. Winn

cc: B. Neff by email (bryan.neff@energy.ca.gov)