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California Energy Commission
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RE: Docket No. 14-CHP-1

Dear Commissioners:

Attached are SDG&E's responses to the questions from the CEC workshop concerning the benefits, challenges, and practical solutions to incentivizing combined heat and power resources in California. Should you have any questions, please do not hesitate to call.

We appreciate the opportunity to provide input to this important proceeding.

Yours sincerely,

Combined Heat & Power in California

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?

SDG&E Response: There are benefits to CHP which should be counted, but the benefits should real and should not be double counted.

- CHP provides capacity benefits that are measured by the CAISO and CPUC Resource Adequacy (RA) rules. Market price benefits are created by any added generation and so should not be counted in addition to the capacity benefits. The analysis of CHP benefits can consider the capacity or market price benefit, but both cannot be included without double counting.
- CHP provides energy benefits.
- CHP may provide avoided line losses if the CHP is used at the location.
- CHP may provide avoided transmission costs if 1) it is located in a load center and 2) avoids fossil generation located elsewhere in the state.
- CHP may provide GHG emissions reductions compared with standalone electricity generation and thermal production. It depends on the GHG intensity of the CHP facility, the GHG intensity of the standalone boiler, and the GHG intensity of the utility's portfolio. From EPA's Clean Power Plan, GHG intensity varies tremendously across states; in high coal use states, gas-fired CHP will provide significant GHG reductions. The same is true across utility portfolios within the State; utilities relying heavily on coal will see substantial GHG reductions from including gas-fired CHP in its portfolio. The table below from the SoCalGas paper presented at the workshop shows how the GHG intensity for a utility (in this case Southern California Edison) has changed and will change in the future. The amount of GHG savings from CHP is reduced as older plants are replaced by CCGTs, and as renewables become a greater proportion of the portfolio.

Table 1. Estimated GHG Savings from SCE's Existing CHP Fleet

	Mid 1990's	Today	2020	New CCGT	*EPA CPP*
Implied Heat Rate	9,402	8,547	7,692	7,000	4,906
GHG Intensity	1100	1000	900	819	574
Boiler Efficiency	80%	80%	80%	80%	80%
CHP Efficiency	65%	65%	65%	65%	65%
Power-Heat Ratio	0.8	0.8	0.8	0.8	0.8
GHG Savings (%)	55%	39%	23%	10%	-29%
GHG Savings (MMT)	2.2	1.5	0.9	0.4	-1.1

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

SDG&E Response: Unfortunately, the CAISO representative did not address this aspect at the workshop. SDG&E's view is the grid operators need dispatchability from fossil electric generation resources, including CHP. The intermittency and variability of renewable energy resources can be better managed with flexible electric generation. Unfortunately, as indicated at the workshop, CHP is designed to meet the thermal requirements of the business operation and so the electricity produced is must-take for the grid operator unless combined with other technologies (such as is the case of CHP as part of a micro-grid).

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?

No response.

b. How should this data be collected, obtained, and/or distributed?

No response.

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

No response.

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?

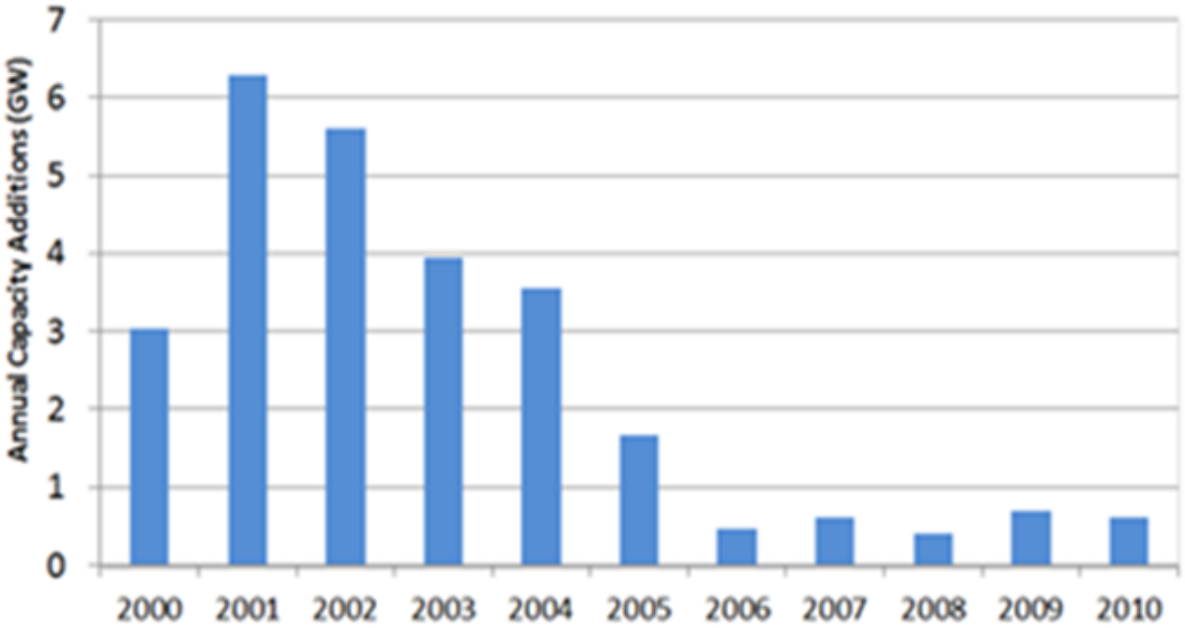
SDG&E Response: CHP has benefits of reducing line losses if located in load centers, but the other side of the coin is that there is an increase in criteria pollutants in the load center. Both ARB and the CPUC have been considering the co-benefits of GHG reduction from energy efficiency and renewables through the reduction in criteria pollutants. For CHP, if line loss benefits are included, then the offsetting cost of increased criteria pollutants should be included. A second important cost of CHP that should be included going forward is the cost associated with increased over-generation. CHP as a must-take baseload resource will increase the amount of over-generation. The cost of dealing with over-generation through renewable energy curtailments or adding energy storage should be taken into account. A recent E3 analysis, *Valuing Energy Storage as a Flexible Resource, Final Phase 1 Report for Consideration in CPUC A. 14-02-006,* June 19, 2014 attempts to quantify the cost of over-generation and finds there are potentially significant costs to over-generation. These costs to deal with over-generation should be included for must-take baseload CHP that will exacerbate the over-generation problem. At the workshop, the CAISO indicated it was going to look at the research on the impact of more baseload resources on the amount of over-generation; that information should be incorporated into the record of the workshop.

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

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)?

SDG&E Response: From the workshop and as reported in prior CEC reports, private developers need very high returns to decide to install CHP (3-5 year payback). All factors cited - upfront cost, ongoing operation and maintenance, electricity rates, and price of natural gas - will affect the payback. In addition, natural gas price volatility or expectations of price volatility seem to play an important role as demonstrated by the chart presented in the SoCalGas morning workshop presentation for CHP additions in the U.S. as a whole. The tremendous decline in CHP installations occurred in the U.S. at the same time that natural gas prices rose substantially and then spiked.

U.S. CHP Capacity Additions



2. What impacts do departing load charges have on the viability of developing new CHP resources?

SDG&E Response: Anything that affects revenues and costs will affect the payback required by private developers including departing load charges. However, if subsidies are determined to be needed to encourage a technology such as CHP, it is more straightforward to provide direct subsidies such as through the SGIP program, through above-market electricity contracts for exports to the grid, through state tax incentives, or through subsidies from the cap-and-trade program allowance revenues. It is inappropriate for the CEC to promote changes in electric or gas rate designs; rate design is in the purview of the CPUC and local governing boards.

a. How do these impacts compare to the net impacts of CHP generation on ratepayers?

SDG&E Response: This question is irrelevant. If greater subsidies are needed, the subsidies should be straight-forward and not through changes to rate designs established by the CPUC and local governing boards. The level of incentives should be provided directly and should be adjusted to reflect the State's perception of the value provided by fossil CHP compared to alternative technologies. For example, in the SGIP program, energy storage and fuel cells receive 4 times the incentive of fossil CHP. SDG&E would note that only 10 percent of available SGIP funds in its service area are reserved for fossil CHP since it was re-incorporated into the SGIP program in 2011.

b. What analyses and/or studies are needed to fully quantify CHP impacts?

SDG&E Response: See response to question 5 in the first section above.

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?

SDG&E Response: The question should be outside the range of inquiry of the CEC as rate design is in the purview of the CPUC and local governing boards. Each of the components of the SDG&E departing load charges are 1) for programs the CPUC has deemed important, or 2) charges related to costs incurred on behalf of the customer in the past. SDG&E departing load charges include charges for Public Purpose Programs (state mandated low income, energy efficiency, renewable generation programs, and research and development); Nuclear Decommissioning; Department of Water Resources Bond Charge recovering historic shortfalls incurred by the DWR that have been financed through the issuance of bonds; the Power Charge Indifference Adjustment recovering the costs of utility-owned generation resources, that became active on and after January 1, 2003, in excess of a CPUC approved proxy of the market price of electricity; and the Competition Transition Charge recovering the cost of power purchase agreements, signed prior to December 20, 1995, in excess of a CPUC approved proxy of the market price of electricity. All except the first in the list are not indefinite, but reflect long-term investments made on behalf of the customer in accordance with state policy and are only collected as long as the cost is incurred.

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.

No response.

5. What regulatory changes, if any, are needed to better balance utility interests, CHP developer interests, thermal host needs, and State GHG reduction targets?

No response.

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?

No response.

b. How does the availability of the feed-in tariff affect your decision to pursue a CHP project in California?

No response.

c. Are there any deficiencies in the current implementation of AB 1613? Please explain.

No response.

d. What should be done to better inform project developers about the requirements of the ISO and utility interconnection processes for electricity export?

No response.

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)?

SDG&E Response: No. 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) were based on certain assumptions about economic and energy growth prior to the recession and not considering other AB 32 policies. ARB cut forecasted reductions from other complementary policies (RPS and energy efficiency) by 50 percent due to the recession. In addition, a recent 2012 CEC study (CEC-200-2012-002) indicated that ARB's efficiency and emission assumptions for CHP were substantially overestimated.

Further, AB 32 policies have reduced the economic potential for CHP. Energy efficiency has cut energy growth substantially. Price reductions in rooftop solar units have expanded that technology much more than forecast, many at retail locations that may have had economic potential for CHP. Further, California GHG policies including the cap-and-trade program discourage energy intensive manufacturing in California, cutting opportunities for installation of new cost effective CHP. In addition, the 33% RPS has reduced the GHG content of the separate production of electricity so that the emission reductions from installation of CHP are substantially reduced, reducing the GHG benefit from CHP compared to renewable technologies.

SDG&E would note that the 2012 CEC study by ICF (CEC-200-2012-002) found technical potential of 1,024 MW of CHP in the SDG&E service territory and market potential by 2020 of 141 MW

(base case) to 247 MW (medium case). In spite of that calculated potential, SDG&E has held two RFOs and has yet to receive a single bid to build new CHP in its service area. And as mentioned previously, the SGIP program run by the California Center for Sustainable Energy, has had only about 10 percent of SGIP funds reserved for fossil CHP projects, totaling roughly 10 MW of new projects.

2. How should the State meet these goals?

SDG&E Response: The State adopted those goals for the purpose of GHG emission reductions. The State should recognize the changes that have occurred in the last seven years and adopt flexible policies to achieve GHG reductions at the lowest cost. Where CHP will reduce the GHG emissions of a utility's/retail sellers portfolio, it should be pursued if the cost per metric ton of reduction is comparable to other GHG reduction options.

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)?

SDG&E Response: No, the State should adopt an approach of setting targets for GHG reduction and not targets for specific technologies. If CHP is a desired technology, the State should incent its development through state policies such as providing investment tax credits and subsidies funded from cap-and-trade revenues.

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

SDG&E Response: No, the current CHP programs do not align with market needs. More emphasis should be given to bottoming-cycle and renewable CHP, which have larger GHG benefits; CHP that provides local reliability where needed, as in the SDG&E service area; and CHP combined with other technologies that can provide dispatchability.

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)?

No response.

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

SDG&E Response: Bottoming-cycle CHP applications and CHP combined with other technologies that will create dispatchability (e.g., microgrids) should be research priorities.

V. Electrical Generation Unit and Reference Boiler Efficiency

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)?

SDG&E Response: CHP characteristics and associated GHG reductions differ by size, technology and application. For analysis purposes, CHP should be categorized by characteristics that will yield significantly different GHG levels per MWh of electricity produced.

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)?

SDG&E Response: The installation of CHP should not be viewed in isolation of the significant changes to the GHG content of standalone electricity due to existing and future changes from California's AB32 policies including the Emission Performance Standard, Energy Efficiency, the 33 percent RPS requirement, and the State's 2030 GHG reduction goals. CHP facilities contracted now will be built by 2020 and will last for 30 years to 2050. Once in place, CHP offers no added GHG reduction, but does lock in a level of GHG emissions. Analysis should be conducted on a utility-specific basis. For utilities like SDG&E, with no coal in its portfolio, displaced electricity should not take a short-term view that renewable energy is fixed, but should take a long-term view that displaced grid electricity for SDG&E is two-thirds gas-fired and one-third renewable energy regardless of whether the CHP electricity is used behind the meter or is sold to the grid.

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)?

SDG&E Response: Thermal efficiency should be measured on the same basis as CHP efficiency. If CHP efficiency is based on manufacturer's specifications, the thermal should be based on manufacturer's specifications for a standalone boiler measured at high heating value (HHV) that meets California's efficiency standards. If the CHP assumes heat rate improvements in the analysis, similar efficiency improvements should be assumed for the thermal source. If CHP efficiency is based on actual performance, the actual efficiency of recently installed boilers should be utilized.

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?

SDG&E Response: The CEC study completed by ICF identified high load factor CHP and low load factor CHP. Thermal utilization should be based on the application. Most large CHP already measure useful thermal output for purposes of FERC reporting and most small facilities report useful thermal output for SGIP reporting. No added metering requirements should be put in place, but if useful thermal output is measured already, it could be reported to the CEC.

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.

SDG&E Response: The Energy Commission staff's approach to estimating fuel displacement is a short-term approach, assuming dispatchable resources are backed down. The regression approach assumes that the heat rate improvement of the past will continue in the future. As stated, "The proposed method does not make any specific assumptions about the retirement of existing resources, the addition of new resources (preferred or otherwise), the impact today's preferred resource procurement will have on future procurement, the impact the operation of these new resources will have on existing resource operation, the emphasis on a 'flexible' grid (requiring resources that will be tasked with ramping more quickly and more frequently than in the past), and future renewable procurement policy and legislation."

The proposed method does not allow for evaluation of future improvements of the GHG content of standalone electricity and thermal production apart from the linear trend and does not consider the addition of thousands of MWs of renewable energy except to the extent it adds generation to the supply curve.

The proposed method would have no consideration of SDG&E's addition of over a 1,000 MW of renewables in the next three years to its portfolio and no consideration of SDG&E's near flat load forecast through 2024 due to increased energy efficiency, and no consideration of the Federal or State's future goals for GHG reduction from SDG&E electricity generation portfolio.

For SDG&E, with relatively no CAISO market imports other than firming-and-shaping contracts, with no coal in its portfolio, and reaching 33% RPS in the near future, all out-of-the-local-area must-take topping cycle CHP generation will increase the GHG content of SDG&E's portfolio. Given the importance of the GHG content of electricity portfolio to measured GHG reductions, as shown in the presented studies at the workshop, SDG&E would suggest that any CEC GHG reduction calculation should be done on a long-term basis, including the addition of renewable energy, and on a utility-specific basis. It should acknowledge explicitly the utility's current portfolio and whether the action assists in lowering the GHG content of the portfolio and in meeting the Federal and State 2030 goals for GHG reduction for electricity.

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

SDG&E Response: No. The approach ignores that long-term, one-third of added standalone generation in the SDG&E portfolio will be GHG-free renewable energy.

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

SDG&E Response: Both cost effectiveness analysis and GHG reduction provided by CHP should consider that CHP is replacing one-third renewable energy post-2020. This approach is similar to that used by the CPUC in evaluating the cost effectiveness of energy efficiency.

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.

SDG&E Response: Setting aside the general disagreement with a short-term approach, the answer is no if applied to energy efficiency or renewable energy with different patterns of saving/production throughout the day or across months in response to weather.

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

SDG&E Response: No. The emissions rate for the SDG&E portfolio is well below the 906 lbs./MWh. Adding CHP that produces 800 lbs./MWh would increase the GHG content of the SDG&E electric generation portfolio, while this analysis would indicate it would be a benefit.

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

SDG&E Response: Setting aside the general disagreement with a short-term approach, the use of two heat rates floor assumes away the over-generation issue. If renewables are on the margin 10 to 20 percent of the time as suggested by the E3 report, then there should be a third category of zero GHG marginal electricity production. In addition, it does not capture the impact on the reduced efficiency of running CCGTs at a lower capacity.

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

SDG&E Response: Setting aside the general disagreement with a short-term approach, the resource shuffling provisions of the ARB cap-and-trade program render coal as a must-take resource so that from a short-term marginal approach, it cannot be displaced except in the long-term.

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

SDG&E Response: Setting aside the general disagreement with a short-term approach, the line loss factor is probably too high for SDG&E. In 2013, total generation and purchases exceeded retail sales by 5.5 percent.

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

SDG&E Response: Setting aside the general disagreement with a short-term approach, the use of a heat rate floor assumes away the over-generation issue. If renewables are on the margin 10 to 20 percent of the time as suggested by the E3 report, then the heat rate will trend downward regardless of the maximum efficiencies and low heat rates of a CCGTs and peaking generation.