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California Energy Commission
Docket Office, MS-4
1516 Ninth Street
Sacramento, CA 95814-5512

Re: California Energy Commission Docket No. 12-IEP-1D: Combined Heat and Power in California

To Whom It May Concern:

On February 26, 2011, the California Energy Commission ("Energy Commission") held a Committee Workshop on Combined Heat and Power in California ("the Workshop") in connection with the 2012 Integrated Energy Policy Report Update ("2012 IEPR Update"). Southern California Edison Company ("SCE") welcomed the opportunity to participate in the Workshop and to provide these additional written comments for your consideration.

California's Combined Heat and Power ("CHP") Program[1] and the Assembly Bill ("AB") 1613 Program provide sufficient incentives to support CHP development. Given the relatively recent adoption of both programs, SCE cautions against altering these new programs, or promulgating new and potentially contradictory policies, until sufficient time has passed so that the State can effectively evaluate the effectiveness of these programs. Specifically, SCE would like to be certain that the information regarding the market availability and cost of CHP resulting from the Investor Owned Utilities' ("IOUs") first CHP Request For Offers ("RFO") solicitations, which are presently in process, is available before altering existing policies.[2] In SCE's view, the information drawn from these solicitations will be helpful for informing effective CHP policy in the long-term.

[1] On December 21, 2010, the Commission issued Decision (D.) 10-12-035, which approved the "Qualifying Facility and Combined Heat and Power Program Settlement Agreement" (Settlement) entered into by Southern California Edison Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, The Utility Reform Network (TURN), the California Cogeneration Council, the Independent Energy Producers Association, the Cogeneration Association of California, the Energy Producers and Users Coalition, and the Division of Ratepayer Advocates (DRA) (collectively, Settling Parties). The Settlement provides a detailed and comprehensive framework for a Qualifying Facility and Combined Heat and Power Program (QF/CHP Program) in California. Among other things, the Settlement includes a procurement framework for Qualifying Facilities and Combined Heat and Power facilities. D.11-07-010 modified the cost allocation discussion in D.10-12-035.

[2] Each of the IOUs will ultimately hold three CHP RFOs during the first 48 months after the Settlement Effective Date (as defined in the Settlement). All three IOUs have now commenced their first CHP RFOs.

The CHP Program has created a framework for promoting efficient CHP that is aligned with the best interests of California's market participants and electricity customers. The CHP Program provides a smooth transition for existing CHP QFs above 20 megawatts (MW) to market-based compensation through CHP RFOs to be conducted by the State's three IOUs and establishes a greenhouse gas ("GHG") emissions reduction target that, going forward, promotes the development of new, efficient CHP consistent with the State's environmental policy goals.

The CHP Program's RFOs create a mechanism through which CHP developers compete for long-term contracts, thereby ensuring that some of the benefits created by CHP projects will be captured by the state's electricity customers. Unlike administrative pricing mechanisms, the CHP RFOs will be a competitive process with negotiated contracts, which allows cost savings and efficiency gains of a particular project to translate into direct savings for utility customers. For example, a CHP developer who diligently negotiates with their site's steam host can reduce the cost of investing in a given CHP facility and make a site more attractive in the CHP RFO. Without an RFO structure, savings resulting from such activities will not translate into savings for electricity customers.

Furthermore, the CHP Program design creates a viable pathway for CHP development while simultaneously requiring potential projects to demonstrate that they can provide real benefit to California. Determining the potential for further efficient CHP development is an inherently difficult task due to the uniqueness of each industrial and commercial site. In contrast, the CHP RFOs will actually leverage individual customer site knowledge by creating a market for efficient CHP. As a result, these programs will reflect a market view of the potential for efficient CHP. For the abovementioned reasons, allowing time for these RFOs to be implemented is preferable to investigating and pursuing further CHP incentive programs in the 2012 IEPR Update.

After the first 48 months of the CHP Program, during the Second Program Period, the IOUs will pursue additional procurement of CHP as necessary to meet a GHG target. This will (1) encourage development of efficient CHP and (2) allow the cost of GHG reductions from potential CHP projects to be compared to other GHG reducing measures. As contemplated in the CHP Program documents and as indicated in the California Public Utilities Commission's ("CPUC") presentation at the Workshop, the existing CHP fleet alone will not be able to meet the GHG emissions reduction targets in the Second Program Period (as defined in the Settlement). SCE strongly believes that a GHG reduction target, taking into consideration utility need and the cost of alternative products, is the appropriate metric for promoting CHP development because it directly incentivizes any system efficiency gained from these projects. Other policy metrics run the risk of promoting inefficient systems at above-market costs.

One of the CHP Program objectives is the procurement of cost-effective and efficient CHP and SCE was pleased to note ICF's emphasis that the focus of CHP policy should be on "the cost effectiveness of GHG reduction."[3] The CHP Program's Second Program Period goals directly address this issue and, importantly, the CHP Program provides parties the flexibility to adjust the

[3] http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-16_workshop/presentations/02_Darrow-Hedman-Wong-Hampson_ICF_International.pdf

GHG target as knowledge is gained from the CHP RFOs. The CHP RFOs will provide real data on the potential and price for GHG reductions from CHP and this information should be used to inform and update program goals as needed. Doing so will help ensure that the state can cost-effectively pursue GHG reduction goals maximizing customer value. Only CHP that can provide cost-effective GHG reductions relative to other GHG reducing measures should be pursued.

At the Workshop, presentations by ICF and the CPUC both clearly show how the effectiveness of CHP as a GHG reducing measure is affected by the State's other environmental policies. SCE agrees that developing and implementing policies designed to promote efficient CHP development without considering how such systems fit into the State's long-term energy and environmental goal creates the a risk of investing in projects that will become obsolete in the foreseeable future. The California Clean Energy Future's GHG intensity metric forecasts a 35% reduction in system GHG intensity from 2008 to 2020.[4] SCE recommends that the Energy Commission regularly re-evaluate the efficiency standards required for program participation. Doing so will ensure that the efficiency of CHP projects keep up with the changing GHG intensity of the grid. SCE is committed to pursuing efficient CHP that provides demonstrable benefits to the State's electricity customers and looks forward to working with the Energy Commission to ensure that such development occurs.

Finally, SCE would like to stress that using departing load and standby charges to prevent shifting costs from customers with CHP to customers without CHP is not only appropriate but essential. SCE's departing load charges are designed to the cover costs associated with programs that provide benefits to all electricity customers in its service territory. At the Workshop, TecoGen and SunPower claimed that CHP is the equivalent of installing an energy efficient lighting system and therefore, should be exempted from non-departing load charges. However, unlike energy efficient lighting, CHP facilities are not actually diminishing site electric load, which is still connected and using the electrical grid for balancing. Site load is simply being served by an additional source - CHP generation. Therefore, CHP generators should still bear the costs associated with this electric load.

Additionally, SCE's standby charges are necessary to recover the costs of providing standby and back-up service for CHP systems. When a customer installs a CHP system, SCE is still obligated to provide the infrastructure necessary to meet that site's full electrical load. Absent standby charges, customers without CHP systems will pay for some of the costs associated with serving CHP customers; this cross subsidy to CHP may encourage the installation of fundamentally uneconomic systems. For the reasons stated above, eliminating departing load and standby charges would artificially inflate the value of potential CHP sites and therefore, would not be in the best interests of all electricity customers.

[4] http://www.cacleanenergyfuture.org/documents/StatewideGreenhouseGas.pdf

As always, SCE appreciates the opportunity to submit its comments. Feel free to contact me regarding any questions or concerns.

Sincerely,

/s/ Manuel Alvarez

Manuel Alvarez, Manager
Regulatory Policy and Affairs
Southern California Edison Company

SCE COMMENTS IN RESPONSE TO CEC IEPR LEAD COMMISSIONER WORKSHOP ON COMBINED HEAT AND POWER TO SUPPORT CALIFORNIA'S AB 32 CLIMATE CHANGE SCOPING PLAN

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

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

SCE is concerned that use of aggregate electrical and thermal profile assumptions will overstate modeled operating efficiencies and thus, overstate potential GHG savings. In SCE's experience, a significant amount of variation in real-time electricity use profiles exists between customers with similar annual load factors, and these differences often result in very different operating characteristics for the modeled plant. Furthermore, SCE expects higher efficiency applications to require incrementally fewer incentives to become cost effective to the customer than lower efficiency applications. Therefore, additional incentives will induce marginally less efficient CHP. Referring to tables D-3, D-10, D-17, which summarize the modeling output for SCE, we see that Average unit Emissions Savings per MWh increases from 331.9 to 341.7 between the Base Case and Medium Case and then declines from 341.7 to 299.7 between the Medium Case and the High Case. SCE would expect to see a far more significant reduction in Average unit Emissions Savings per MWh. SCE suspects that this phenomenon is a result of assuming CHP operating hours based on annual data, which will not capture the efficiency impacts of load-following or venting waste heat to match site needs.

The cumulative incentive costs reported on page 124 are understated because they only include the cost of the Self Generation Incentive Program ("SGIP") and the 10 percent investment tax credit in the High Case. These figures should also include the incremental cost of Market Price Referent ("MPR") relative to Short-Run Avoided Cost ("SRAC") pricing or a measure of market pricing, the re-distribution of departing load charges and standby charges to non-participating customers, and the $50/kW-yr transmission and distribution capacity deferral payment, which is assumed without any justification or basis. Additionally, the High Case adjustments to CHP capital costs and the market acceptance model make it impossible to draw any policy conclusions from this scenario.

Similarly, the statement on page 127 that "CHP would save customers $740 million per year in energy costs under the Base Case and $2.9 billion per year under the High Case" should be changed to refer to *participating* customers unless sufficient analysis is done to estimate the costs borne by non-participating customers to create these savings. This distinction is important because incentives for CHP largely benefit one class of customers at the expense of another class of customers.

The ICF Base Case assumes AB 1613 pricing for all units 20 MW and smaller. This is not accurate as it is likely that there will be a mix of 20 MW and under generators in the AB 1613 program and the PURPA program. Additionally, the description of AB 1613 on page 15 of the report appears to be incorrect. The description seems to imply that only CHP facilities of non-profit organizations are allowed to participate in the AB 1613 program; this is not the case.

SCE recommends adding clarification that the assumption in the Medium and High Cases that over 20 MW pricing is based on MPR is an estimate only. Pricing will be set via competitive solicitations, which may be lower and/or higher than MPR. Following approval by the CPUC of QF/CHP Settlement, the Federal Energy Regulatory Commission relieved the California IOUs from the PURPA must-take obligation from QFs larger than 20 MW. Therefore, any assumptions including administratively-set pricing for CHP larger than 20 MW are simply inconsistent with applicable law.

SCE would like additional clarity regarding combined cooling heating and power ("CCHP") modeling and the underlying data behind ICF's operating assumptions. In SCE's experience, CCHP has only been cost-effective in very specific applications with a large, constant cooling need.

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

For the reasons stated above, the ICF report does not present adequate information to determine the appropriateness of further regulatory changes.

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

If the crux of this question is whether the "Air Resources Board Scoping Plan Assumptions" for avoided generation emissions, electric line losses, and avoided boiler efficiency set forth on page 122 of the report are appropriate, SCE's answer is that the assumptions appear out of date.

- "Avoided Electricity GHG Emissions" of 0.437 metric tons/megawatt-hour appears inflated and conflicts with current ARB Mandatory Reporting Regulation ("MRR") default emissions rate of 0.428 MT/MW.
- The assumed 80% boiler efficiency may also be outdated. Higher efficiency boiler options are now commercially available.

II. Small and Large CHP project development in California

NOTE: SCE declined to address the questions in Section II directed to "CHP Developers and Project Owners," and Section III ("Technology Innovation to Overcome CHP Barriers") as these questions are not applicable to SCE, and for the sake of brevity, has not included those questions here.

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

To the extent that CHP is more efficient than conventional resources, the cap-and-trade program will provide an additional incentive for the utility to contract with new CHP instead of conventional, higher-emitting resources. However, the uncertainty around GHG allowance prices – caused by the startup of the market and the uncertainty surrounding the long-term life of

California cap-and-trade – may make it difficult for both the utility and the developer to accurately gauge the monetary benefit of reducing GHG.

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

SCE does not believe net-metering should be expanded to additional CHP technologies. To do so would add layers of subsidies to generators that have already established their technical and commercial viability in the marketplace without net-metering and whose viability in CHP applications should be predicated on their demonstrating superior thermal efficiency to separate heat and power applications.

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

SCE's AB 1613 program started implementation on December 15, 2011, upon approval by the CPUC of SCE's program documents, including the two standard contracts and the SCE "Schedule CHP" tariff. While SCE is committed to its AB 1613 program, SCE believes there are deficiencies in the current implementation of AB1613, and SCE will work with the CPUC and program stakeholders to make appropriate incremental improvements.

To this end, SCE remains concerned about the treatment of resource adequacy ("RA") benefits under the AB 1613 program. The underlying statute states that AB 1613 generators should provide RA benefits to the purchasing utility.[1] Under current RA program rules, the only way to do this is to request a Full Capacity Deliverability Study, obtain Full Capacity Deliverability Status, and become an RA resource. Unfortunately, under current interconnection rules, projects interconnecting under the state-jurisdictional Rule 21 interconnection tariff do not have a pathway to pursue Full Capacity Deliverability Status and become RA resources.

To address this shortcoming in the current interconnection rules, the CPUC, with SCE's support, promulgated the "interim solution" for AB 1613 generators interconnecting via Rule 21. The interim solution states that projects interconnecting via Rule 21 "shall not be required to provide Resource Adequacy Benefits, and Buyer's total obligation to obtain Resource Adequacy Benefits pursuant to the Resource Adequacy Rulings with respect to service area of Buyer will be decreased by the Generating Facility's generating capacity." SCE emphasizes that this approach should be considered an interim solution only. Once there is a clear pathway for Rule 21 interconnecting generators to become RA resources, AB1613 generators should be required to fulfill the requirements associated with providing RA benefits, as required under the statute. The CPUC has reserved the right to amend the AB 1613 contracts and tariffs as necessary pending the resolution of the deliverability issue in its Distributed Generation ("DG") interconnection proceeding (R. 11-09-011) and/or its RA proceeding (R. 09-10-032).

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[1] AB 1613 states that "[t]he physical generating capacity of the combined heat and power system shall count toward the [RA] requirements of load-serving entities for purposes of Section 380."

In addition to the treatment of RA, SCE remains concerned that AB 1613 program pricing requires SCE's customers to pay more for AB 1613 generation than they receive in benefits. First, the AB 1613 program establishes administratively set prices. SCE opposes such pricing schemes and recommends setting power prices via competitive, market-based processes. Next, the current administratively set AB1613 pricing scheme compensates AB 1613 generators as if they are providing a firm product. In fact, the generation provided from an AB 1613 project will be an as-available product. Current AB 1613 pricing also gives generators located in certain areas a 10% Location Bonus. This 10% bonus is simply not supported by underlying data. A generic locational adder is an inappropriate method for compensating program generators.

III. QF Settlement and Infrastructure Planning

NOTE: SCE has omitted the "Questions for CPUC" from this section.

Questions for the Investor-owned Utilities

The QF Settlement establishes the conditions under which the IOUs may fall short of both the MW and GHG emission targets. Failure to reach MW targets may be justified by a lack of sufficient offers, inefficiency of resources offered relative to the double-benchmark, excessive offer prices, and the amount of GHG emissions reductions, but may not be made based on lack of need or portfolio fit arguments. The latter, however, may be used as justification for failure to meet GHG emission reduction targets.

1) How is the portfolio fit of a prospective resource measured? Which attributes of the resource influence its fit into an existing portfolio? Which of these attributes have the greatest influence on portfolio fit?

In general terms, SCE's least cost, best fit procurement first examines SCE's need for energy and related products over the term of the proposed contract. Such need is the difference between SCE's load forecast and the generation resources expected to be added to its portfolio to meet that need. To assess the portfolio fit of a prospective resource, SCE compares the energy and related products that it would expect to receive by contracting with the resource against its forecasted need. If the resource fills a need, and offers a better value than competing options for filling the same need, the resource is more likely to be offered a contract.

SCE hosted a meeting on January 13, 2012 to discuss the CHP RFO process. A recording of the presentation and the accompanying presentation material can be found on SCE's website at the following address: http://www.sce.com/EnergyProcurement/renewables/chp.htm.

Portfolio fit is increasing in importance as California adds more and more must-take generation (e.g., solar, wind, geothermal, in addition to more CHP). California will increasingly find itself in the perverse position of having to pay parties to take electricity during hours when minimum generation on the electric grid exceeds the actual demand for generation. It is important that California policymakers understand and see the natural tension of adding more intermittent must-take renewable energy and simultaneously adding must-take CHP to the same grid. The policy toward CHP and renewables needs to be paced because being over-zealous in such a pursuit can result in perverse results.

NOTE: SCE has omitted the "Questions for CHP Representatives" from this section.

Questions for All

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

SCE fully intends to achieve the CHP Program's targets; however, estimating the peak capacity of CHP development during 2013 to 2022 would be highly speculative without the results of the CHP RFOs and other market data that would inform such a planning effort. As indicated at the Workshop, significant uncertainty exists surrounding the cost and GHG benefits of potential CHP projects, which are highly dependent upon the efficiency of the CHP projects that bid into our solicitation.

Prior achievements of programs similar to the CHP program are not indicative of what future achievements of the CHP program. In SCE's experience, highly efficient CHP projects are cost-effective. As a result, many of the state's most promising CHP projects already exist because they have already participated in past CHP programs. Additionally, one aim of the CHP Program is to create a pathway for retiring or repowering the state's most inefficient CHP facilities, which of course could reduce the total amount of CHP capacity in the state, depending on whether facilities choose to retire or repower.

As part of the IEPR Electricity Demand Forms, SCE submits a forecast for CHP capacity in our service territory. While this forecast was developed prior to November 23, 2011 the beginning date for the CHP Program, forecasted incremental capacity additions between 2011 and 2020 are comparable to the ICF Base Case.

IV. General Questions for All

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

SCE suggests two additional lines of work. First, the Energy Commission should conduct a rigorous cost-benefit analysis of existing CHP incentive programs on a $/GHG reduction basis. Such an analysis will enable policymakers to better understand the relative costs of differing GHG reduction measures. Second, the Energy Commission should conduct a strategic review of the role CHP should play in the post-2020 period. The results of such a study will help inform the appropriate efficiency standards to ensure that incentives are not directed towards projects that will ultimately compromise the state's ability to achieve any longer term GHG reduction goals.

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

From SCE's perspective, a broad array of incentives is already available for CHP development. Therefore, the question is not whether the state should create incentives, but rather whether the state should create additional incentives. There is no need for the state to create additional incentives for CHP development at this time, as there are already multiple incentives in place, and these new incentives have just begun implementation.

For example, the AB 1613 program is available for CHP generators 20 MW and under meeting program requirements. The PURPA PPA is available for other CHP generators 20 MW and under that do not meet AB 1613 requirements. Moreover, CHP generators 5 MW and larger can participate in the IOUs' CHP RFOs and obtain a CHP RFO PPA. The IOUs' targeted procurement is 3,000 MW for the initial program period, the first 48 months of the CHP Program. The IOUs will likely need to secure additional MWs to meet the second program period GHG emissions reduction target.

The CHP Program requires any IOU that does not achieve its MW or GHG targets to make a showing justifying why the targets could not be achieved. The CHP Program also provides for the retention by CHP Parties of a CHP Auditor to be designated if an IOU does not, or provides notice it anticipates it cannot, meet its CHP Program targets. Finally, the CHP Program provides for semi-annual reports that will enable CHP stakeholders to closely track progress towards CHP goals and identify issues on a very timely basis.

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

In the near term, policymakers and market participants should focus on the recently established CHP and AB1613 programs. The programs provide development options for all sizes of CHP, and the CHP Program in particular is geared toward development of cost-effective and GHG-reducing CHP projects. The CHP Program sets forth a semi-annual reporting process that will allow stakeholders to track progress towards CHP goals, and could be used to measure progress toward the goal of achieving 6500 MW of CHP by 2030.

At this moment, given the major changes contemplated for California's energy markets and industry, including, but not limited to the 33% renewables portfolio standard, phase-out of certain once-through cooling plants, smart grid improvements, and electric vehicles, SCE believes it is too early to identify any additional long-term actions for achieving goals beyond 2020. As stated above, work could be done to analyze the results of these new programs once sufficient time has passed such that this is feasible.

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

No additional steps are needed at this time. The CHP Program and AB 1613 program have the mechanisms to incent CHP development and stakeholders should give these programs time to work as designed. The state should focus on these existing programs and evaluating their effectiveness before considering any additional steps to encourage further development.

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

Bio-powered CHP has the same set of market opportunities available to traditional CHP, and in addition, can take advantage of market opportunities available for RPS-eligible generators. As an initial matter, bio-powered generators 500 kW and larger can participate in the CAISO markets.

With regard to bilateral contracting opportunities with SCE, bio-powered CHP can participate in three separate power procurement programs:

First, bio-powered CHP can participate in SCE's annual All Source Request for Offers ("RFO"), where SCE seeks offers on a variety of products including dispatchable unit contingent energy-only tolls, non-dispatchable qualifying facilities resources, resource adequacy capacity products, and daily financial call options. More information on SCE's All Source program is available at http://www.sce.com/EnergyProcurement/ESM/AllSourceRFO/all-source-rfo.html .

Second, under SCE's CHP Program, bio-powered CHP 5 MW and above can participate in the CHP RFOs. Bio-powered CHP 20 MW and under may also sign up for either a PURPA PPA or an AB 1613 contract if the CHP meets applicable program requirements.

Third, with regard to Renewables Portfolio Standard ("RPS")-eligible bio-powered CHP, there are at least three procurement program options:

- SCE's annual RPS Request for Proposals ("RFP") for projects 1 MW and larger.
- SCE's semi-annual Renewable Auction Mechanism ("RAM") auctions for projects 20 MW and smaller.
- SCE's CREST renewable feed-in-tariff program for generators up to 1.5 MW.[2]

Of course, other investor-owned utilities have similar programs. Bio-powered CHP can also sell to publicly-owned utilities, or to third parties not mentioned above.

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

It is SCE's understanding that such challenges are similar in nature to the challenges faced in developing other technologies. Such challenges may include securing a reliable fuel source, obtaining operating permits, procuring equipment, securing financing, completing the interconnection study and interconnection facility installation process, among others.

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

The issue is not whether the Energy Commission or State can do something to increase market penetration of bio-powered CHP, but rather whether the Energy Commission or State *should* take such action. As described in (5) above, bio-powered CHP enjoys the same market opportunities as other CHP, but can also take advantage of opportunities available to RPS-eligible generators, thus putting the technology in an advantageous position relative to non-renewable CHP. SCE recommends that the Energy Commission and State let the market determine which renewable and non-renewable technologies offer utility customers the most benefit at the least cost, rather than taking any positive action to artificially increase the market penetration of one technology (at the expense of other technologies and utility customers).

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[2] SCE's current Section 399.20 renewable feed-in-tariff program, CREST, will be replaced by the new Section 399.20 renewable feed-in-tariff program current in the implementation phase in R. 11-05-005. Among other changes to the current program, the new program will be available to RPS-eligible generators up to 3 MW

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

One of the Facility Owner Goals and Objectives under the CHP Program is "improvement in business and regulatory certainty." From SCE's perspective, the CHP Program and the recently-launched IOU AB 1613 programs do a great deal to resolve regulatory uncertainty for CHP development. The CHP Program sets forth targets designed to support the procurement of thousands of MWs of CHP. The AB 1613 program provides tariff-based must-take standard contracts for CHP resources meeting AB 1613 requirements. Given that there are now clear, comprehensive rules in specific programs tailored for CHP procurement, at this point SCE has no additional recommendations on regulatory actions that would reduce uncertainty for CHP.

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

SCE has no further input as to the potential development of renewable CHP beyond its responses in (6) and (7) above.

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

SCE's concerns regarding the AB 1613 program are set forth in Section II(3) above. SCE comments further that AB 1613, as an administratively-priced feed-in-tariff, should not be viewed as a magic bullet for CHP development, for the reasons described below. SCE recommends that the Energy Commission look to the principles underlying the CHP Program, such as, securing cost-effective GHG reductions, moving to viable, market-based compensation for CHP, and settling decades-old QF/CHP litigation, as the key to effective CHP development. While AB 1613 is a statutory program, implementation of the program must be consistent with these principles.

The CPUC has a degree of latitude during any implementation proceeding to develop program implementation details. SCE emphasizes that any further adjustments to the current AB 1613 program should be consistent with the principles outlined above. With regard to reducing litigation and achieving regulatory certainty, SCE notes that administratively-priced feed-in-tariffs can be contentious and time-consuming. AB 1613 implementation was delayed due to disagreements over the administratively-set pricing scheme, whether generators should be required to provide RA benefits pursuant to the underlying statute, and what contract provisions should appear in the standard contracts, among other issues. Any future modifications to the program could entail similar delays. The potential regulatory uncertainty associated with administratively-priced feed-in-tariffs is a significant disadvantage of such programs.

Next, with regard to compensation for CHP resources, SCE stresses that such compensation should be market-based and not set by administrative fiat, which can distort the market for eligible CHP projects. For example, AB 1613 pricing pays generators as if they are firm resources despite the fact that they provide an excess, as-available product. Further, to the extent an AB 1613-eligible project is interested in bidding into an IOU CHP RFO, the AB 1613 administratively-set price creates a price floor that allows AB 1613 generators to bid higher-than-AB 1613 prices into the IOUs' CHP RFOs. In fact, the AB 1613 contracts provide Sellers a unilateral termination right in the event Seller is selected in a competitive solicitation by the utility Buyer. SCE remains concerned about the distorting effect AB 1613 generation could have on bid prices in its competitive solicitation under the CHP Program.

Third, with regard to cost-effective GHG reductions, AB 1613 requires the IOUs to enter into contracts for up to 10 years. As a mandated procurement program, AB 1613 does not give the IOUs the ability to decline a prospective AB 1613 project and enter into a more cost-effective of procuring equivalent products and securing GHG emissions reductions. Thus, as time passes, SCE encourages the CEC and other policymakers to closely examine the cost effectiveness of any GHG reductions attributable to AB 1613 projects to ensure that customer funds are not being diverted away from more cost-effective GHG reduction strategies.

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

Generally speaking, SCE is not inclined to pursue development of CHP, or acquire existing CHP resources. However, there are three specific instances where SCE could consider developing CHP:

(1) grid reliability projects (unlikely match for CHP technology);
(2) fuel diversity (e.g., resources or technologies not expected to be developed by the market); and
(3) market backstop, in situations where the market is not working as anticipated.

In summary, while utility development/ownership is an option for CHP, SCE's position is that such options should be exercised only if there are no market alternatives and if the option provides the best value for utility customers compared to alternatives.