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California Energy Commission
Dockets Office, MS-4
Re: Docket No. 11-IEP-1A
1516 Ninth Street
Sacramento, CA 95814-5512

RE: COMMENTS ON JOINT AGENCY CLEAN ENERGY FUTURE WORKSHOP

Dear Commissioners:

The Sempra Energy Utility (SEU) companies appreciate the opportunity to comment on the draft staff report, *California's Clean Energy Future (CCEF).* While we appreciate the Joint Agencies' ambitious goal to describe "key elements on which the state is relying to achieve its 2020 electricity and natural gas policy goals", we believe there are pivotal issues of vital importance that were not included in the report. It is important that the issues below are addressed as the staff develops the tools to implement the plan in order to adopts a sustainable plan.

1. The State Must Consider Cost-Effectiveness and Rate Impact in Developing Energy Policies

While cost effectiveness has been a key part of energy efficiency programs in California for decades, we are struck by the complete lack of reference to cost effectiveness of distributed generation in any of the materials. The fact is that the plan envisions that distributed generation substitute for other generating resources in meeting the State's energy needs. Those other resources are subject to rigorous "least-cost, best fit" analyses. Furthermore, in implementing the Renewable Portfolio Standard, the Public Utilities Commission is charged with the responsibility of setting a limit on the expenditures that retail sellers must incur in meeting the RPS, and to report the rate impacts of the program.[1] In contrast, the proposed materials place no cost cap on distributed generation, impose no cost–effectiveness evaluation, and provide no discussion whatever on the rate impacts of distributed generation, in comparison with the resources it might displace.

In the context of considering the impacts of 33% renewables, the Public Utilities Commission has concluded that a "High DG" case would cost the state billions of dollars of added expense. [2] This

[1] (Public Utilities Code Sections 399.15 (c)-(f), and 910, as added by SBx1 2 (Ch. 1, Stats of 2011-12 First Extraordinary Session)
[2] California Public Utilities Commission, *"33% Renewable Portfolio Standard Implementation Analysis: Preliminary Results"*, June 2009.

analysis did not consider any additional costs that might be imposed to accommodate, without adverse operating impacts, large quantities of distributed generation on distribution facilities. From California ratepayers' standpoint, such a scenario is far from the most cost-effective means of meeting a 33% RPS. California should not automatically conclude, as the Implementation Plan appears to, that the State should pursue substantial amounts of added DG without any understanding of the relative cost, and without any reference to cost-effectiveness. The State should not ignore the PUC's preliminary analysis that doing so would cost the State billions of dollars in added costs and resulting rate increases. Furthermore, as discussed below, the State should not ignore the potential operating impacts of large amounts of added DG, whose cost to mitigate could be substantial, if mitigation is feasible at all. Distributed generation programs should be subject to the same kinds of cost effectiveness tests that energy efficiency and renewable procurement already are subject to.

2. Distributed Generation has Significant Potential Operating Impacts That Could Affect The Quantity and Location of Distributed Generation That is Feasible Without Substantial Cost

The discussion on distributed generation omits the fact that as DG, particularly intermittent DG, is added to distribution circuits, it has increasing negative impacts on those circuits, including severe voltage fluctuations, and operation at voltages that exceed the low or high limits permitted for distribution operations. These characteristics could impact customer equipment, cause unacceptable voltage fluctuations, and could affect distribution system facilities. Prudent electrical system operation necessitates that these impacts be identified and addressed, but to do so would impose substantial additional cost in order to accommodate substantial increase levels of DG. [3] Additionally, these impacts are not limited to effects on the distribution system, but could affect upstream facilities as well. SDG&E has previously testified at the CEC that DG can have several impacts on SDG&E's system that must be addressed,. For example, during low load hours, large amounts of DG, when combined with in-area generation needed to maintain system stability would exceed the local load, resulting in generation curtailment because of transmission system constraints. Even if there were no constraints during such periods, it could potentially require SDG&E to build facilities sooner than or at sizes larger than needed to serve load and export power. This could impact local industrial development bonds that SDG&E has used to provide financing at favorable rates. If that were to occur, the Company might be forced to defease those bonds, raising rates to our customers.[4]

3. Any Consideration of a Program To Increase Net Metering Must Recognize the Cost Shifting and Rate Impact of Such a Proposal

The Implementation Plan states that "There is an ongoing interest in simplifying NEM billing and enhancing consumer information and awareness of NEM program rules to accelerate the adoption of NEM." It is not at all clear if the Plan contemplates expanding the current program, or reforming the

[3] At the CEC May 9th, 2011 IEPR Workshop on Localized Renewable Generation, SDG&E presented materials showing large DG penetrations will impact both the T&D grid with a $550 M and $54 M/year investment in transmission and distribution respectively. http://www.energy.ca.gov/2011_energypolicy/documents/2011-05-09_workshop/presentations/

[4] Testimony of James Avery, IEPR Committee Workshop, "Distributed Generation – Getting to 2,000 MW by 2020", May 9, 2011

current program in order to allow it to be sustainable in the long term. Net metering is in essential need of reform if rooftop solar is to be a sustainable program. Under current rules, it imposes substantial cost on customers not participating in net metering. Under the program, net metering customers receive electricity service from the utility at a deeply discounted rate. They also receive free integration, storage and reliability services. Other customers fund this discount and are also required to pay for this integration, storage and reliability service, as well as for all of the public purpose programs the State has adopted to benefit all Californians.

Today, customers have an incentive to pursue net metering because it allows them to avoid paying many of the costs of service. A typical net metered residential customer avoids paying for the following --

- Distribution costs
- Transmission costs
- California Solar Initiative
- Self-Generation Incentive Program
- CARE (low income support – residential only)
- Low Income Energy Efficiency (LIEE – residential only)
- Public Interest Energy Research (PIER)
- The Public Goods Charge portion of renewables programs
- Energy efficiency
- Demand Reduction
- Nuclear decommissioning
- Reliability services (used to be called "reliability must run)
- DWR bond charges
- Competition Transition Charge

The costs that net metering customers do not pay do not go away. The net metering customers continue to depend on utility transmission and distribution systems as a storage device to serve them. Each of the public interest programs continues to require funding. All of these costs continue to be incurred but the net metering customer avoids paying for much of them and someone else has to pay those costs instead. The resulting cost shift is substantial. For example, in the residential sector, high upper tier rates result in a shift in costs to other customers of nearly 20 cents/kWh.

Customers who are hardest hit by this cost shift are residential customers not protected by CARE and not wealthy enough to afford the generation that would allow them also to shift costs to someone else. Those who benefit from this shifting of costs are typically more wealthy customers. At SDG&E, nearly half of our net metered residential customers have incomes over $100,000 annually, while only 10% of our net metered residential customers have incomes less than $50,000. Thus, higher income customers can use net metering as a means to avoid supporting low income programs such as CARE. The resulting costs are typically paid for by those customers in the middle who can't afford generation, and are not poor enough to qualify for CARE. This is neither fair, nor sustainable.

Many things have changed since the net metering law was first adopted. When it was originally adopted in 1995 (SB565 (Alquist) Ch.369, Statutes of 1995), net metering was envisioned to cover a modest amount of capacity that was not expected to have any significant impacts on other customers. It was specifically limited to capacity totaling 1/10th of 1 percent of peak demand (for SDG&E – 3.6

MW). In 1998, that law was amended substantially to the form it is today, except for the cap. (AB1755 (Keeley) Ch.855, Statutes of 1998). At that time, staff analysis did not express concern about the impact of facilities on customer rates or on electric system operation because, as the analysis stated – "The best estimates are that there are roughly 30 net meter customers in the state, which is less than 1% of the current cap." Today, SDG&E has over 13,000 net metered customers exceeding 100 MW.

The impact of this large amount of net metering has been further magnified by changes in rate structure caused by the energy crisis. When first adopted, the investor-owned utilities did not have the dramatic tiered pricing required by current rates. Whereas in 1995, customers could avoid prices of ten or twelve cents/kWh, resulting in relatively modest shifting of costs to non-participants, today, they avoid prices of 30-40 cents/kWh, because current tiered pricing forces upper tiers to pay far above the actual cost to serve. The result is significant rate impacts, and significant cost shifted to non-participating customers – typically, relatively lower income customers.

Furthermore, by giving customers price signals that services such as storage can be obtained for free, net metering as it is currently required, harms opportunities for the provision of competitive services such as storage. California is embarking on ambitious renewable DG and net zero energy home policies, but DG and net zero customers receive all of their storage services for free. This is particularly problematic in light of the Commission and legislative interest in promoting storage procurement by utilities; the need for these resources is being created by customers that will not have to pay for them. In addition, there is absolutely no incentive for these customers to invest in distributed storage; customers do not volunteer to pay for a service they already receive for free.

California aspires to achieve ubiquitous deployment of renewable DG and to implement net zero construction policies. All of these customers use and require storage services. They should have access to price signals that allow them to receive these services from their utility or to self-provide these services with customer-owned storage. If California fails to adopt retail price signals for storage services, customers that do not have distributed generation (often customers that cannot afford it and/or who do not own a home) will be increasingly required to pay for these services to the benefit of wealthy customers that can afford DG. This is not fair, does not build a bridge to a low carbon future, and is not sustainable.

4. The State Needs to Ensure That Publicly Owned Utilities Participate in All Programs On an Equivalent Basis, With Equal Accountability for Results.

The Implementation Plan discusses a number of energy issues with presumably important statewide impacts. However, many of these programs are not implemented with the same degree of zeal by Publicly Owned Utilities as State statute and by California regulators require of investor owned utilities. Indeed, DG requirements largely do not apply to POUs at all. Although POUs are required to implement the California Solar Initiative, there is no oversight or accountability, and, as a result, POU progress in adding solar is anemic at best.[5] Likewise, reporting on POU energy efficiency performance suggests that POUs are falling further and further behind in energy efficiency implementation.

[5] See http://www.energy.ca.gov/sb1/pou_reports/index.html

For example, according to the latest available report from the Energy Commission, in 2008, POU energy efficiency as a percentage of sales was only a quarter of that achieved by the IOUs. This is not a reflection on all POUs. Some have a good track record. But, it is an expression of concern that State policies favoring various key energy programs are not uniformly applied, and their cost burden is not being uniformly felt by all electric consumers.

5. Specific Issues With Clean Energy Future Metric Review

We have a number of concerns with the Clean Energy Future Metric Review. First, SEU agrees with many of the commenters at the workshop that the proposed metrics lack coordination and reflect the silos of the various agencies and the Governor's office. The fact that the CCEF Installed Capacity metric shows the addition of 26,500 MW of new non-dispatchable electricity capacity is incompatible with Energy Efficiency goals in the current low economic growth environment. Unless there is significantly more economic growth than currently forecast by the CEC, the amount of new capacity is limited by the Energy efficiency goals. If no new load exists, the 26,500 MW goal cannot be met.

Even with some load growth, the 33% RPS goal and the dispatchable capacity needed to allow for the integration of variable renewable energy on the grid will limit the amount of non-dispatchable capacity. The amounts of new capacity for the IOUs is currently being evaluated in the CPUC long-term procurement proceeding and should not be prejudged by an installed capacity metric.

SEU would recommend dropping sector-specific GHG goals or modifying it to be the 1990 GHG levels for the electric sector. ARB has more than once indicated that the 2020 goal is a statewide goal and not a sector-specific goal. Further, an electric sector GHG emissions measure is misleading since statewide GHG reductions through electricicification in the industrial or transportation sectors would increase measured electric sector emissions. Further, adding CHP will reduce measured electric sector emissions simply due to onsite electricity being classified by ARB in the industrial sector. Lastly, current ARB mandatory reporting rules do not provide GHG reductions for out-of-state renewable contracted for by California utilities that cannot produce an e-tag from the same region, while AB 32 and the CEC have included those renewables as GHG reductions. So, there is a disconnect between ARB measurement and State definitions of GHG for the electric sector.

CCEF should add two or three metrics that are comprehensive and comparable to the types of metrics reported by other countries and regions. For example, GHG emissions per capita, GHG emissions per dollar of personal income (or gross state product), and/or energy intensity per capita might be useful measures. These are comprehensive across all sectors and include all energy uses, not just electricity use. This type of comprehensive measure would avoid problems inherent in sector-specific measures described above and provide a simple-to-understand metric; a metric that is currently reported for countries and/or states. Controlling for population and economic activity also gives a truer picture over time so that GHG reductions occurring due to recession or declining population do not give the State an undeserved pat on the back, or that high economic growth and ballooning population do not mask the significant efforts aimed at reducing GHG in the State.

CCEF metrics should not include any metrics that have a variable, debatable baseline. For example, the Energy Efficiency metric as proposed requires a baseline that is dependent on the level of economic activity and measurement of what would have occurred but for the State's actions. As it is, if the economy stays in recession, the EE savings goals may not be met but the goals of reduced energy use may be met. Likewise, the amount of energy savings depends on the assumptions about what would have occurred but for the State's actions. This will change over time if the comparison is to the rest of the United States as new laws are enacted in the U.S. The amount of energy savings may be less than the goal simply because the rest of the country adopts California's leadership on EE and enacts laws similar to California. Better measures would be the energy intensity of the existing stock of buildings and the energy intensity of the new stock of buildings. The same problems arise if the CCEF were to consider any jobs measures. The variable baseline of what jobs would have been created if California's energy dollars had been spent on less expensive conventional energy plus general consumer spending from that savings on energy is highly debatable and speculative.

The CCEF 1000 MW goal for energy storage is inappropriate because of the diversity of types of storage, the different costs for fast acting batteries versus thermal energy storage versus pumped hydro and a clearly defined need role for storage. Setting a MW goal prejudges the CPUC proceeding investigating whether there should be targets and would likely lead to energy storage being installed in the wrong place at the wrong time, with the wrong characteristics and at a higher cost.

Discussion of alternative and renewable fuel technology programs should include growth and development of the natural gas vehicle (NGV) market as well as the electric vehicle sector. The Plug-in Electric Vehicle target should be modified if the 2020 target goal is "infrastructure and capabilities to necessary to absorb a targeted 1 million fully electric and plug-in hybrid-electric electric vehicles." The goal should measure the infrastructure rather than vehicles. The metric should be in terms of the geographic distribution of public fueling stations and the number of home connections if it is to be compatible with the goal. Similarly, a natural gas vehicle target should be established, again any target established should address the development NGV of infrastructure, rather than number of vehicles. For both electric and natural gas vehicles, measuring the cumulative number of vehicles is at odds with the State's approach of providing price signals and letting the market decide. The low carbon fuel standard and the GHG cap-and-trade program provide incentives for the least cost transportation solutions taking into account the GHG externality, so a quantity goal for a particular technology is not appropriate. The only appropriate quantity goals for a technology are those goals mandated by the California legislature.

Responding to discussion question 6 in the presentation, SEU recommends that the CCEF metrics do include reliability and cost. Both of these measures can be quantified and used for references though the goal setting may be difficult since the uncertainties of the costs of integrating electricity variable renewables, both distributed generation and utility-sized renewable, are high. Hence having these as a reference is useful but they probably should not be used as a metric and the cost of becoming cleaner while maintaining reliability can and should be reported. Or, alternatively, the cost of becoming cleaner in terms of reduced reliability can be measured. System average rates in California provide a measure of costs, while various reliability measures have been used in the past (SAIDI, SAIFI, and MAIFI).

Sincerely,