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Chairman Robert Weisenmiller
Commissioner Karen Douglas
California Energy Commission
Dockets Office, MS-4
Re: Docket No. 11-IEP-1D
1516 Ninth Street
Sacramento, CA 95814-5512

Re: "Docket #11-IEP-1G Renewables" Implementation of 12000 MW DG Goal

Dear Chair Weisenmiller and Commissioner Douglas:

Thank you for the opportunity to submit these comments regarding policies to implement the Governor's goal of 12,000 MW of distributed generation (DG). The California Municipal Utilities Association (CMUA) is a statewide organization of local public agencies in California that provide electricity and water service to California consumers. CMUA membership includes electric distribution systems and other public agencies directly involved in the electricity industry. In total, CMUA members provide electricity to approximately 25 percent of the population in California. CMUA appreciates the work of the staff at the California Energy Commission (CEC), their colleagues in the Governor's office and sister agencies, and their consultants in developing initial analyses and discussion questions related to the feasibility and potential policies for implementing the Governor's goal.

CMUA's General Comments:

CMUA and its members have actively supported renewable energy development and distributed generation, in addition to our continued support for energy efficiency, and reduction of greenhouse gases and air pollution. CMUA supported AB 32, and both the 20% and 33% renewable energy standards.

CMUA also strongly supports clean local generation – many of these resources complement the needs and goals of our member utilities. CMUA is committed to working with state policymakers and other stakeholders to achieve additional clean local generation. In pursuit of this goal, CMUA believes that the following factors must be considered:

- **Interaction with Other Policy Goals** – The state has many different policy goals that are jointly acting to change the electrical system in California. The new 33% renewable portfolio standard, the development of the smart grid, the state's strong energy efficiency programs and targets, AB 32, cap and trade, and similar policies all are acting to change grid and resource development. A new target of 12,000 MW of distributed generation must be coordinated with these policies, allowing stakeholders flexibility to meet the goals in a manner that is least cost and best fit for each service area. For example, the enactment of the 33% RPS allowing use of Tradable Renewable Energy Certificates (TRECs or RECs) implies that "behind the meter" distributed generation resources can and will contribute to the RPS goal, and that recognizing this is most important when considering the Governor's proposed DG goal. The interaction between the goal of 12,000 MW of DG and California's other renewable energy procurement goals is discussed further in comments submitted by the Sacramento Municipal Utility District. A second example is the interaction between smart grid development and the capability to reliably integrate large amounts of distributed generation. Development of significant distributed generation without this capability will be inherently more complicated and costly. Finally, the State is taking tangible steps, with associated expenditures, to interconnect utility-scale renewable resources. Evidence of this is the $7.2 billion transmission expansion plan approved by the California Independent System Operator Corporation (CAISO) on May 18, 2011. These efforts and expenditures must be balanced with DG goals.

- **Grid Reliability** – it is paramount when considering the addition of substantial distributed generation to the grid that reliability be maintained. Californians enjoy reliable electrical service today, and the benefits of clean local generation would be substantially reduced if grid reliability were lowered. CMUA appreciates the attention that the CEC is paying to the grid and reliability experiences in other countries with dramatic increases in distributed generation – lessons learned in those circumstances can be adapted to California's grid structure to prevent loss of reliability.

Power Quality issues especially at the distribution level will need to be addressed in order to integrate distributed generation. There are significant costs independent of grid reliability costs, which are associated with mitigating the effects of intermittent distributed generation. Power quality is often essential for commercial and light manufacturing as well as residential customer satisfaction (brown outs, flickering lights and damaged electronics do not make customers very happy). Further, at the wholesale level, significant penetration of non-dispatchable resources that may not be visible to the system operators raises both reliability and market efficiency issues that must be addressed.

- **Cost-effectiveness** – While there are clear benefits to clean local generation, there are also potential additional costs. In order to avoid significant rate and bill impacts for utility customers it is critical to consider the costs involved in developing resources in small increments, costs to maintain power quality and to manage more complex reactive power schemes, stranded cost if this initiative leads to over-procurement of resources, and social justice issues of cost placed on non-participants. California's economy, though recovering, is still weak, and additional costs without commensurate benefits will harm the recovery.

• **Timing** – When considering the above factors, the timing of developing additional distributed resources becomes critical. Adding substantial amounts of these resources when their costs are relatively high and when they may not be needed given current system resources and contracts under development will lead to unnecessary costs and possibly stranded resources, the full costs of which must still be recovered even as their use is decreased when distributed generation resources are increased. In addition, time is needed to fully understand the effects of distributed generation, particularly intermittent distributed generation, on the reliable operation of the grid, and to implement those grid changes necessary to preserve reliability. CMUA is concerned that a date of 2020 for a goal of 12,000 MW of clean local generation will not allow adequate consideration of resource needs and reliability issues, and urges consideration of a later date for such a goal.

• **Eligibility** – CMUA believes that a variety of resources should be considered eligible for the clean local generation goal, including combined heat and power, biomethane and biogas resources. We recommend that the commonly-accepted definition of distributed generation be adopted for implementation of the 12,000 MW DG goal, which is:

> "DG facilities are most frequently defined as non-centralized electricity power production facilities less than 20 MW interconnected at the distribution side of the electricity system. DG technologies include solar, wind and water-powered energy systems; and renewable and fossil-fueled internal combustion (IC) engines, small gas turbines, micro-turbines and fuel cells."[1]

Allowing for this scope of resources with different characteristics and differing local availability can provide flexibility for grid integration the potential to reduce costs and avoid reliability and power quality issues. The goal should also include existing and proposed clean local generation from current programs and resource plans. CMUA is pleased to see the State begin with a solid accounting of these existing programs and resources – there is no need to duplicate or complicate what the State has already developed or committed to with these earlier programs.

• **Flexibility** – We should consider that each specific policy goal, such as the 33% RPS and the proposed 12,000 MW of clean local generation, not only should be coordinated but should be considered in light of the ultimate end goals of these policies – reducing the carbon footprint of the electricity system, decreasing our customers' exposure to volatile electricity prices, and providing for a reliable, stable, and clean electricity system. When these goals are first in mind, allowing each entity the flexibility in meeting the overall goals based upon local conditions – such as resource potentials and transmission constraints – will help to meet the goals most cost-effectively.

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[1] "Impacts of Distributed Generation, Final Report", prepared for California Public Utilities Commission, Energy Division Staff, by Itron Inc., January, 2010, Chapter 3.1 Definition of Distributed Generation Resources, page 3-3. This definition is nearly identical to that in the California Energy Commission Staff Report, "Distributed Generation and Cogeneration Policy Roadmap for California", March, 2007, page 4: "For this report, staff defines DG as electricity production that is on-site or close to a load center and is interconnected to the utility distribution system. In practical terms, this limits the definition of DG to less than 20 megawatts (MW) since systems larger than this would typically be interconnected at sub-transmission, or transmission system voltages. This definition includes such technologies as photovoltaics; small wind; small biomass; small combined heat, and power (CHP) or small cogeneration; small combined cooling, heat, and power (CCHP); and small non-CHP systems."

CMUA's Answers to Specific CEC Questions:

I. Developing Interim and Regional Targets for 12,000 MW by 2020

1. **Please suggest a methodology for setting interim and regional targets building to the 12,000 MW goal by 2020. Considerations to address include: state and local policies, the capability of the distribution system, economics, and resource availability. To aid discussion, staff has identified the following options for parsing out the goal:**

- **Set targets for each load serving entity or county.**
- **Set targets per sector, for example, residential, commercial, public, or other.**
- **Set separate targets for installations that serve on-site load and for projects that produce energy for wholesale.**
- **Set targets by utilities' portion of coincident peak.**
- **Set targets based on resource potential and/or best use of the distribution system.**

Response: As mentioned above, CMUA and its members have been leaders in developing and implementing policies, goals and programs that are well aligned with State policies. CMUA members also put high priority on ensuring reliable and sustainable power at reasonable cost. Our continued high rankings on reliability metrics statewide and our continuing trend of relatively lower prices are testament to our success in effectively balancing our goals of increasing renewable energy and lowering GHG emissions with those of providing low cost, highly reliable electricity. Our ability to balance these objectives is made significantly easier because we enjoy the flexibility to consider the conditions and requirements in our local service areas, pursuing renewable resources and other resources as we need them to meet our combined policy, cost, and reliability goals.

CMUA believes that the methodology that should be considered for the Governor's proposed DG goals should: 1) recognize the amount of DG already built and established in program pipelines to avoid penalizing "early action" efforts to deploy DG; 2) be based on a thorough understanding of the differences in costs, feasibility, and system impacts of DG resources across various service areas, rather than based on a simple percentage of peak load per utility or some other arbitrary factor; and 3) recognize the timing of need for new resources (if any), allowing flexibility so that local conditions can be reflected on an ongoing basis as the proposed goal is pursued without stranding already procured assets; and 4) the amount of acceptable subsidy for non-participating customers to "behind the meter" participants.

CMUA believes that overly prescribing the path by which utilities attain the proposed goal, via arbitrary timing, technology, or geographical targets, is likely to result in economic inefficiencies (e.g., investments being made too early, investments made in less cost-effective technologies, etc.).

2) Related to the above question, some utilities have noted in the California Public Utilities Commission's Rule 21 Working Group and its Renewable Distributed Energy Collaborative (Re-DEC) that up to 15 percent of peak load for individual circuits could reliably interconnect with minimal system upgrades. Other utilities have said that individual circuits could handle distributed

generation additions for up to 50 to 100 percent of minimum load. Could a 15 percent of peak load or 50 to 100 percent of minimum load penetration rate be implemented statewide? If so, how much renewable capacity would be installed per utility?

Response: Some CMUA members have been active participants in the standardized Rule 21 development effort in California. And some CMUA members have voluntarily chosen to adopt the same Rule 21 language, screens and procedures as required of the IOUs because they believe standardization of the interconnection processes statewide will benefit the DG community – allowing them cost reductions through consistent requirements regardless of utility service territory. Penetration limits on a per circuit basis such as the 15% of peak load screen have served as a proxy for how much capacity a circuit has for DG interconnections during minimum load conditions, which is one of the conditions utilities worry about. Since there is generally a ratio of 3 to 1 between a circuit's peak load and average minimum load in California, the 15% of peak load is a proxy for 50% of average minimum load.

The 15% of peak load penetration limit could be used as a proxy for a technical estimate for utility capacity for inexpensive interconnections, but CMUA emphasizes that every circuit is different, and every DG installation has somewhat differential effects. Any such proxy would need to account for pre-existing DG projects already interconnected and other considerations peculiar to each circuit. Rule 21 would still need to be followed to ensure that localized constraints don't preclude individual interconnections, even up to the 15% proxy target.

CMUA also notes that the Advanced Metering Initiative (AMI) will significantly improve our knowledge about circuit specific conditions, and in particular minimum loads. This knowledge will improve our interconnection process and capability may eventually foster a detailed circuit by circuit potential rather than the 15% proxy screen.

3) Please provide comments on any methodologies discussed at the workshop. Indicate whether you support or oppose a particular approach and the rationale for your position.

Response: CMUA has no position on this at this time.

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

Response: Rather than concentrating on new incentives or penalties in this instance, CMUA reiterates that coordination with, and building on, existing programs, policies and structures will help to make the proposed DG goal feasible and cost-effective. If the portion of the proposed DG that is renewable is considered part of the RPS, as CMUA advocates, then the general incentive/penalty structure for the RPS will apply, and no new penalties or incentives are needed. If the proposed DG goal encompasses and builds on the distributed solar resources the State is acquiring through the California Solar Initiative, as CMUA advocates, then again, existing incentive and penalty structures will be in effect. If the proposed DG encompasses and builds on the State's mandated and voluntary Feed-In Tariff structures, as CMUA advocates, then no additional penalties or incentives are necessary.

CMUA recommends that to the extent possible, POUs be provided the flexibility to design their own DG programs to deliver those resources in the manner that is most cost-effective given each POU's particular characteristics and constraints, and to structure their programs to balance incentives to encourage DG development with the potential for increased costs for POU customers, in particular to avoid inappropriate cross-subsidies or cost burdens for particular customer groups.

CMUA does have two specific recommendations regarding potential incentive mechanisms.

First, to the extent that the proposed DG goal is expected to be accomplished with additional 'behind the meter' distributed solar resources installed on customer premises, CMUA believes that the existing incentive represented by net metering should be reexamined. The current 5% cap on mandatory net metering acts to limit the cost of this incentive to non-participating customers, and should not be increased, in CMUA's view, without a restructuring of the net metering paradigm to eliminate or significantly reduce the subsidy from non-participating customers.

Second, to the extent that a Feed-In Tariff structure is considered as a manner to help accomplish the proposed DG goal, CMUA stands opposed to the significant costs that are represented by the 'European' model of Feed-In Tariffs that are based upon an administratively determined estimate of the underlying technology costs in varying installation circumstances. To the extent State policy moves forward with a Feed-In Tariff concept, consideration should be given to a Renewable Auction Mechanism that provides incentives for the most cost-effective renewables to be developed and compensated based upon an estimate of the value of the energy to our customers. Lastly, similar to our comments on net metering above, the current 1 MW cap on Feed-In Tariff payments to individual customer-generators acts to limit the cost of this incentive to non-participating customers, and should not be increased, in CMUA's view, without a restructuring of the Feed-In Tariff paradigm to eliminate or significantly reduce the subsidy from non-participating customers.

5) If the State established regional targets, should there be options to trade allocation requirements? If so, how should this be implemented?

Response: As long as the State coordinates the proposed DG goal with existing clean generation policies and allows flexibility on using many types of clean local generation to meet the proposed target, as well as allows flexibility on contract terms, location of the resource, and the use of RECs for renewable resources, there is no need to have a separate market to trade allocation requirements. Such trading will already happen in the existing RPS and carbon markets, without needing to establish another complicated and duplicative trading structure. However, to the extent the state limits the types of local clean generation, mandates that the proposed goal must all be procured through specific, distributed, small scale production structures, or sets stringent minimum terms for new contracts, then flexibility to trade allocation requirements may be necessary to keep costs and rates down and at the same time allow an effective to way to be compliant.

6) What are the near-term and long-term actions needed to achieve 12,000 MW by 2020?

Response:
Near-term: make sure existing programs are on track, alter to meet goals if necessary.
Long-term: design and develop extensions of existing programs; only add new programs at the end of existing programs if necessary.

In the near-term, the State needs to make sure that existing programs intended to foster increased clean local generation are on track, and modify them as needed. Achieving the proposed goal depends upon building upon the success of these existing programs. The State also must clarify the eligibility of renewable distributed generation for meeting the requirements of the RPS targets, pursuant to the enactment of the 33% RPS requirement which explicitly allows TRECs for RPS compliance. Coordinating these existing policies and building upon them will lead to easier consideration of a proposed DG goal.

In the long-term, federal and state governments and private sector equipment manufacturers need to continue investing RD&D dollars in DG technologies. The first costs of DG technologies such as solar photovoltaic systems are still high in comparison to most electric generation technologies, there are still issues related to integrating and interconnecting DG into the existing electricity system and grid, and there are regulatory barriers such as air permitting in the case of DG biomass and biogas resources. Further reduction in DG capital costs and increases in DG efficiency are necessary so that from a life cycle standpoint DG technologies are more cost competitive with other solutions such as energy efficiency and traditional central station generation sources. In addition, further research is necessary regarding the potential operational impacts on utilities of increased interconnected DG capacity, and potential ways to mitigate these impacts.

II. Discussion on European experience integrating large amounts of DG.

7) How are the European electrical distribution systems similar to or different from California?

Response: The most obvious difference between European distribution systems and those in California is the design of the low voltage systems. Urban European low voltage systems use larger service transformers (about ten times as large) directly serving significantly more customers. These low voltage systems distribute three phase power to every customer site. In contrast California's low voltage systems typically serve a dozen customers and provide only single phase to residential customers.

Away from the urban centers, European distribution systems appear to be more similar to California's.

8) What challenges have European countries encountered from integrating distributed renewables that are applicable to California, what actions did they take to address the challenges, and what lessons are applicable to California?

Response: Spain appears to have taken a position that it will integrate generation up to 100% of the load, but no more. On the other hand, Germany has a position that it will allow generation, well in excess of the load. Nevertheless, the supporting German policies have only been in place a few months, and no system based on this philosophy appear to be in operation. While the KEMA Report provided a brief discussion of some protective relaying issues, no mention was made of the approach required to deal with the substation voltage regulation issues, in the German discussion.

Spain requires the developer to compensate the utility for interconnection costs similar to California, while Germany is socializing these costs.

9) As California builds out its distribution system, what lessons can be learned from the European experience?

Response: We learn very little from Spain's conservative approach, as it is substantially similar to that of some California utilities. Similarly, it doesn't appear that Germany has deployed a significant amount of renewable generation in excess of local load, so the consequences of that approach are unknown at this time. In addition, direct utility control of numerous larger solar fields, as proposed by Germany, may become important for California utilities, perhaps before enough have been deployed in Germany to learn from their experience.

III. Discussion of "Developing Renewable Generation on State Property, Installing Renewable Energy on State Buildings and Other State-Owned Property"

10) Please provide comments on the staff report and on lessons learned from the European or local experience that may be applicable to California.

Response: The staff reported that Germany had identified four quadrant relaying as a requirement for accepting reverse power flows through distribution substation transformers. This was not something CMUA members had considered. (CMUA member distribution substation relays are typically non-directional).

In addition, while inverter vendors in California have been reporting the widespread use of voltage source inverters in Spain, Germany, and throughout Europe, the staff report's actual finding was that Spain and Germany are still using current source inverters, as is the case in California. Nevertheless, Germany is planning on going forward with the use of voltage source inverter based installation, in the near future.

IV. How Research Development and Demonstration (RD&D) can Help Advance Distributed Generation

11) What is the role of RD&D in advancing distributed generation and helping achieve the Governor's Clean Energy Jobs Plan and other current and future state policy goals such as the Renewable Portfolio Standard and AB 32?

Response: The most critical issue facing DG deployments are first costs, operating costs and air permitting in the case of DG Biomass. Federal and state governments, and private sector equipment manufacturers need to continue investing RD&D dollars in

DG technologies. They need to reduce DG capital costs so these technologies can compete with energy efficiency, demand response and utility-scale generation. They need to improve their efficiency, reliability and durability in order to reduce O&M costs so that from a life cycle standpoint these DG technologies are cost competitive with other solutions. Finally, they need to continue to invest in emission reduction technologies so that California is not implementing DG technologies that are worse than central station power production.

12) Please comment on the maturity of distributed generation technologies. Which technologies or components should RD&D efforts focus on to address some of the barriers for advanced DG deployment?

Response: Combustion based technologies such as reciprocating engines and gas turbines are the most mature DG technologies. Microturbines are the next most mature technology, followed by Stirling engines to round out the combustion based technologies. PV technologies have seen great progress in cost reduction and efficiency. Lastly, fuel cell technologies are continuing to see reduction in first costs and operation and maintenance costs.

For reciprocating engines and gas turbines, RD&D is still needed to improve the effectiveness of emission control technologies and their operating costs. Microturbines need to see continued RD&D to reduce their first cost and improving their efficiency. Stirling engine technologies need continued RD&D to improve their first cost, durability and reliability. Fuel cell technologies continue to be hampered by high first costs and high maintenance costs; RD&D is needed to bring these costs down so the fuel cells can compete with reciprocating engines and turbines. RD&D is also needed to reduce fuel cell susceptibility to contaminants in fuels, particularly renewable fuels.

13) Are currently existing technologies and tools enough to power facilities with nearly 100 percent renewables in a technically and economically feasible manner? What are some emerging technologies that may be able to reduce costs when produced at scale?

Response: This is unknown at the present time. Hawaii is dealing with adverse system impacts of high penetrations of PV that is causing the utility to curtail PV power plant output. Penetration limits generally are not as high yet in the U.S. to understand the operational impacts of the intermittency of PV on utility systems. Sufficient tools to enable transmission system operators to plan for and operate distribution-sited renewables, demand responsive load control and energy storage are lacking. RD&D is needed in the continued development of integrated T&D planning and operations tools that will give bulk system operators higher fidelity visibility and control of the distributed assets connected to the distribution system.

14) What issues impede the deployment of distributed generation technologies in utility distribution territories that RD&D can help address? If so, please identify the issue and how RD&D can help in a manner that benefits both the utilities and customers.

Response: Some DG technologies (e.g., solar and wind) have other operational impacts on utilities that tend to increase with increased interconnected DG capacity. The costs of dealing with these operational impacts are typically born by utilities and research should focus on reducing these costs and mitigating these impacts.

For example, high penetration PV creates an operational issue for utilities with respect to planning contingency power. The intermittency of PV production and the industries' emerging capabilities to forecast PV production within the hour, hour-head, hours-ahead or day-ahead is lacking. Consequently, utilities must plan contingency reserves for this aggregate generation in a conservative fashion because forecasting techniques are unproven. RD&D is needed to improve PV production forecasting so that utilities do not over plan contingency power needlessly, thus driving up PV integration costs. Wind integration has similar issues to deal with.

Another example, high penetrations of PV may adversely impact voltage regulation on distribution substations and feeders. It may also impact protection schemes. RD&D is needed to determine new methods for designing and controlling the distribution system with existence of high penetration PV such that utilities can cost effectively maintain service voltages to customers and ensure faults are safely dealt with, all while maintaining high reliability for utility customers.

15) What other future research direction, focus, strategies or initiatives may be recommended for PIER to undertake so that RD&D can better help advance DG?

Response: A portfolio approach to RD&D for DG specific issues as discussed above (e.g., first cost, operation cost, durability, reliability, efficiency, emissions) coupled with grid integration research is needed. Of these two, grid integration is of paramount concern to utilities presently. RD&D to support these two issues in the next 10 years will provide needed knowledge to utilities and customers on how best to deploy and integrate DG and renewables to utility systems and customer facilities. But, synergistic technologies such as demand response and storage may also be able to leverage this grid integration knowledge or may be part of the integration strategy for customers and utilities. Future RD&D should take a broad perspective on how best to meet the customer and utility operational objectives and pursue all cost effective distribution sited technologies including demand response, storage, DG and renewables.

In closing, CMUA again expresses its appreciation of the hard work by CEC staff, their colleagues in the Governor's office and other agencies, and their consultants in the pulling together initial analyses and discussion questions for the May 9 workshop, and for the opportunity to submit these comments. We look forward to participating throughout the remainder of the IEPR proceeding on the development of policies related to the Governor's proposed 12,000 MW DG goal.

Sincerely,

David L. Modisette

DAVID L. MODISETTE
Executive Director