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June 1, 2011

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

RE: Docket No. 11-IEP-1G

Docket Office –

Please find attached PG&E's comments regarding the California Energy Commission's May 9, 2011 IEPR Committee workshop on Renewable, Localized Generation.

Please contact me should you have any questions.

Sincerely,

Dan Patry

Attachment

Pacific Gas and Electric Company Comments in Response to the May 9th IEPR Workshop on Renewable, Localized Generation
Docket No. 11-IEP-1

I. Introduction

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to comment in response to several topics related to Governor Brown's goal of deploying 20,000 megawatts (MW) of renewable energy by 2020, including 12,000 MW of localized energy. We look forward to further collaboration with the California Energy Commission (CEC) and their sister state and federal agencies on how best to shape policies that deliver safe, reliable, cost-effective, and higher levels of renewable energy to our customers. In advance of a more detailed proposal from Staff, PG&E would like to offer the following broad observations first on procurement policy, as well as concerns related to technical integration and interconnection of distributed resources.

PG&E has consistently supported legislation and other regulatory actions that would require higher levels of renewable generation. While supporting the state's aggressive renewable goals, PG&E has advocated for greater program flexibility so that parties can achieve the goals at the lowest possible cost to our customers. At this early stage in considering Governor Brown's localized energy goal, PG&E is seeking to understand more clearly a number of key issues, including how the program fits with existing procurement programs and the recently passed 33% Renewable Portfolio Standard (RPS) by 2020 legislation, what the expectations are for the cost of the program and its impacts on the distribution system, and what the expectations will be for all load-serving entities.

Now that the 33% RPS is law, we are moving forward with implementing the bill's provisions. PG&E believes our focus today should be on implementing the 33% RPS provisions in the most cost-effective manner for our customers and monitoring the results of the program – and the many procurement programs already initiated under the 33% RPS umbrella, many of them just underway – before making program changes or additions. Although the 33% RPS has been under discussion for a number of years, we cannot underestimate the scope and scale of the changes coming to the electricity grid in the next several years as numerous utility-scale renewables projects begin operation. In addition, a number of important programs supporting wholesale distributed generation (DG) renewables have just begun or are about to begin. Securing new DG resources will be best served by implementing these programs in the near-term in order to determine what procurement vehicles work best and result in the most successful build out of new renewable generation.

II. Procurement Principles and Key Programs

A. PG&E has consistently advocated four high-level principles as critical elements of a successful renewable energy policy. These same policies are relevant here as we consider the 12,000 MW of localized energy goal. Adhering to these principles can help us achieve the state's renewables goals, while ensuring adequate customer protections. These four principles are:

1) Expanded eligibility of resources: Access to a broad pool of resources that can be used to reach energy targets provides a wide array of procurement options and projects, mitigates market power among sellers, and helps complying parties achieve the goals at a lower cost to customers. This means that any localized energy goal should recognize a multitude of technologies, deployment approaches (e.g., wholesale DG as well as customer side DG), project sizes and procurement mechanisms.

2) Cost containment: Any program for procurement of additional resources of a particular type must contain meaningful limits on the total above-market costs to achieve the goal in

order to protect customers. PG&E has been actively working for years to add low-cost clean energy to its portfolio, but has emphasized larger, utility-scale projects because they are less expensive on a per kilowatt-hour basis for our customers. While the prices for small renewables projects have been declining, in absolute terms, they are still more expensive than larger projects using the same technology. Recognizing the overall cost of particular programs should be a key tenet in determining the optimal mix of renewables for utilities and other load-serving entities.

3) Flexible mechanisms to meet goals: While additional procurement mechanisms can be appealing, the key remaining challenge to meeting California's aggressive renewables goals is to continue to improve the processes for siting and permitting new renewables projects. While we work to eliminate the structural barriers to renewables development, flexibility in program design is critical so that parties can work toward the achieving the goals in a manner that provides long-term improvements in California's energy mix. This flexibility will help complying parties manage their portfolios in a way that acknowledges that development challenges and delays may occur.

4) Universal application of the rules: All retail sellers of energy – investor-owned utilities, publicly-owned utilities, energy service providers, and community choice aggregators, should have the same opportunities and obligations to achieve state goals, no matter the program.

B. As we look at the 12,000 MW localized energy goal, it is important to consider the existing distributed generation programs. PG&E has many ongoing procurement programs to support distributed generation, and they should serve as both a foundation and a blueprint for any localized energy goal. Many of these programs are just now getting underway after years of planning, and will need to time to ascertain their efficacy. Including existing programs as tools to meet the localized energy goal will also help reduce costs to customers. These programs are described below.

1. California Solar Initiative: The largest solar program of its kind in any state in the country is the California Solar Initiative (CSI), a 10-year, $2.9 billion program designed to help California move toward a cleaner energy future and help bring the costs of solar electricity down for California consumers. The goal of the program is to increase the amount of installed solar capacity on rooftops in the state by 3,000 MW by 2017. With over 45,000 PV systems installed, PG&E has connected more solar customers to the electric grid than any other utility company in the country; this represents roughly 30% of the installs throughout the entire U.S.

2. Self-Generation Incentive Program: PG&E's Self Generation Incentive Program (SGIP) provides financial incentives for the installation of new, qualifying wind or fuel cell self-generation equipment. Solar rebates are currently administered under PG&E's CSI, but were once part of the SGIP. A minimum 30 kilowatt system size for renewable technologies is required for participation in this program.

3. Feed-in Tariffs: PG&E has a 1.5 MW Small Renewable Generator and Public Water and Wastewater feed-in tariff (FIT). As required by Assembly Bill 1969 (Yee, 2006), PG&E is required to procure about 210 MW under the program. It currently has approximately 40 FIT contracts with a variety of technologies including solar PV, small hydroelectric, and landfill gas, and many of them have already achieved commercial operation.

The CPUC is also working to implement Senate Bill (SB) 32 (Negrete McLeod, 2008), which expands the existing feed-in tariff from 1.5 MW to 3 MW and broadens the program beyond IOUs. PG&E expects the CPUC to issue a proposed decision soon. Under SB 32, the statewide cap for the feed-in tariff will be increased to 750 MW.

4. Renewables Auction Mechanism: The Renewables Auction Mechanism (RAM) is a price-only competitive solicitation for renewable generators up to 20 MW in size. The program cap for the three IOUs is 1000 MW over two years. PG&E's share of that cap is about 425 MW, with the first auction expected later this year after CPUC approval of the already-submitted solicitation protocols.

5. PG&E's Solar PV Program: In 2010, the CPUC approved PG&E's 500 MW Solar PV Program (PV Program). Under this program, small solar PV facilities up to 20 MW in size are expected to be developed, with 250 MW coming from utility-owned generation and the second 250 MW to be filled through a series of competitive solicitations. The projects must be located in PG&E's service territory. PG&E completed the first solicitation for projects this spring – receiving and robust response – and expects up to 50 MW of the first utility-built projects from the program to come online this fall.

6. General Renewables Procurement: Under annual RPS request for offers (RFOs) and bilateral negotiations, PG&E has contracted for nearly a dozen small renewable projects (under 20 MW) for over 140 MW. While many of these projects were selected with an emphasis on their high viability, these smaller projects are increasingly competitive with larger facilities, particularly for solar PV.

7. Combined Heat and Power/Qualifying Facilities: PG&E also contracts or will contract with non-renewable distributed generation facilities through standardized contracts (e.g., the AB 1613 feed-in tariff, standardized QF contracts, etc.), with a policy goal of reducing overall greenhouse gas emissions. These programs should also count toward any localized energy goal.

III. Integration and Interconnection

Approximately 50,000 distributed generators are interconnected to PG&E's electric distribution system, the majority of which are small solar photovoltaic systems. To date, the effect of these DG units on PG&E's distribution system has not been significant and PG&E has not need to make significant investments in its distribution infrastructure to accommodate the current level of penetration. While it is possible for additional DG to be interconnected to the distribution system (particularly smaller units, like those interconnected as part of CSI), PG&E does not have an estimate of the amount of additional DG that can be interconnected before significant expenditures are necessary.

In the next several years, it is expected that both the number of DG systems and the size of DG systems (> 1MW) seeking to interconnect to the distribution system will increase significantly. PG&E has limited experience interconnecting and operating its distribution system with many large distributed generation units. PG&E is also concerned about availability of personnel resources to study and project manage these types of interconnections.

With respect to the question of "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?" PG&E reiterates that additional DG can be interconnected to the distribution system. However, the Company does not have an estimate of the potential amount of additional DG that can be interconnected before significant expenditures are necessary.

Whatever amount of additional DG the state targets for electric distribution systems, PG&E believes that the primary considerations should continue to be:

- Safe integration for the public, DG installers/owners and utility workers
- No degradation of power quality or reliability

- Cost-effectiveness

How German Electrical Distribution Systems Differ from PG&E's Systems

The KEMA draft report focuses only on German and Spanish distribution systems (not all of Europe).In reviewing the draft report, PG&E felt that the section describing the German system was more accessible. Consequently, PG&E's comments focus on differences between PG&E and German distribution systems. Based on the information in the draft KEMA report, PG&E perceives the primary differences as:

- Germany requires remote control capability of DG units down to 100kW.
- Transformer sizes for German low voltage (LV) networks (what PG&E refers to as "secondary") are much larger than what PG&E uses. PG&E generally uses 25 to 75kVA transformers while Germany uses 400 to 1000kVA in urban areas and 100 to 400kVA in rural areas. Additionally, it appears that majority of LV networks in Germany are three-phase while most secondary systems in PG&E's service territory are single phase. Finally, it appears that German LV systems in urban areas are fed via more than one transformer (i.e., transformers operating in parallel) which is not usually the case in PG&E's system. These <u>differences affect the amount of DG that can be more easily connected to secondary systems.</u>
- PG&E seems to have a greater number of medium voltage (MV) circuits that have a lower operating voltage (i.e., 4kV circuits) as compared to Germany. <u>4kV circuits are not strong candidates for larger DG systems.</u>
- The allowable service voltage range in Germany is twice the value in California (± 5% in California and ± 10% in Germany). <u>Larger bandwidths provide more "elbow room" for engineers to work with when considering the impact of a DG unit (however, PG&E notes that Germany has a standard for allowable voltage rise of 2% to 3%).</u>
- German MV circuits may use larger conductor sizes in rural areas than PG&E. If true, <u>this has the effect of reducing voltage rise on circuits in rural areas which can facilitate the installation of DG.</u>
- German MV circuits appear more homogenous in terms of three-phase than PG&E distribution circuits. In PG&E's rural areas, where there are more single-phase lines, adding a third phase to interconnect larger DG units will likely be necessary.
- It appears that Germany has more electronic relays in service than PG&E. Depending on their type and functionality; electronic relays are more suitable from a backflow perspective than electro-mechanical relays.

What challenges has Germany 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?

From a distribution perspective, the challenges appear similar and include:

- Voltage (steady state and transient)
- Thermal loading considerations
- Protection schemes

With respect to addressing these challenges, several of the methods described in the KEMA report are similar to what PG&E would consider. The draft report did not appear to address the possibility of inadvertent islanding which is a potential challenge.

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

PG&E's distribution grows by roughly one percent per year in terms of new circuits, new distribution lines, substation transformer banks, etc. which practically means the distribution system is already "built out." Given this level of annual system modification, there is not much to leverage in terms of system design (i.e., it is not practical or cost effective to modify PG&E's distribution system to mirror Germany's distribution system). PG&E is installing more electronic relays as it installs new breakers and replaces older ones.

Communication systems that allow remote monitoring and operation of DG units; volt-var optimization software; and inverter design/operation represent some of the ways to facilitate a high-level of DG penetration on the distribution system.

Possible areas of further study

PG&E notes that the following areas may be worthy of further investigation:

- Relationship between how DG penetration increased in Germany and the corresponding evolution of technical requirements
- Typical sizes of DG interconnected to German LV and MV systems
- Typical characteristics of German MV circuits as compared to distribution circuits in California (e.g., circuit capacities, circuit loading, typical main-line protection arrangements, circuit lengths, etc.). This might also be insightful to know from a substation transformer bank perspective.
- DG penetration levels in context, meaning statistics describing the cumulative amounts of DG interconnected to German LV and MV systems (by type if possible) as compared to California primary and secondary distribution systems
- How German distribution system operators address the potential for unintentional islanding as a function of the amount of DG, types of DG, different inverter types and manufacturers, etc.
- Information regarding the interconnection application and study process in Germany (timelines, resources devoted, etc.)
- Information regarding the costs incurred by German distribution system operators for modifying LV and MV systems to achieve the current level of penetration (the "socialized costs" of picking the "low-hanging" interconnection fruit)
- What information do German distribution operators provide DG developers to assist them in project siting?
- Before large volumes of DG were interconnected in Germany, were there estimates of the potential of DG penetration and, if so, how accurate where the estimates?
- How much is direct-transfer trip used for larger DG installations on MV circuits in Germany?
- How many and what size DG units are typically interconnected to MV substations? What is the typical configuration and design (i.e., open-air bus vs. metal-clad, etc) of MV substations in Germany?

IV. Conclusion

PG&E appreciates the opportunity to comment on the initial stages of understanding the impacts of higher penetration rates of localized energy resources on procurement, interconnection and integration practices. We look forward to further opportunities to engage in a thorough process to better understand these issues.