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VIA E-MAIL DOCKET@ENERGY.CA.GOV

California Energy Commission
Dockets Office, MS-4
Re: Docket No. 13-IEP-1F
1516 Ninth Street
Sacramento, CA 95814-5512

Re: 2013 Integrated Energy Policy Report: Lead Commissioner Workshop on Increasing Demand Response Capabilities in California – Comments of Pacific Gas and Electric Company

Pacific Gas and Electric Company ("PG&E") appreciates the opportunity to provide comments on the California Energy Commission's ("CEC" or "Commission") Lead Commissioner Workshop on Increasing Demand Response Capabilities in California ("June 17 Workshop"), as part of the 2013 Integrated Energy Policy Report ("IEPR") proceeding.

In addition to the CEC, the future of demand response ("DR") is being considered by the California Public Utilities Commission ("CPUC") and the California Independent System Operator ("CAISO"). PG&E has participated actively in these proceedings and refers the Commission to its Comments on the CAISO Demand Response and Energy Efficiency Roadmap and Workshop.[1]

I. INTRODUCTION

PG&E is an active supporter of DR and a leader in the field. PG&E has over 700 megawatts ("MW") of operational DR, of which approximately 500 MW are dispatchable within 30 minutes and approximately 200 MW are automated. Moreover, PG&E was the first to bid Proxy Demand Resources ("PDR") into the wholesale energy market in 2011 and 2012; in 2013,

[1] Abreu, K., & Tougas, L. (2013). *Comments of Pacific Gas and Electric Company: CAISO Demand Response and Energy Efficiency Roadmap and Workshop*. Pacific Gas and Electric Company. Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-06-17_workshop/caiso_dr_workshop_materials/PGE-CommentsDemandResponse-EnergyEfficiencyRoadmapWorkshop.pdf

PG&E will bid flexible DR into the wholesale market through PG&E's Intermittent Renewables Management 2 pilot.[2]

As outlined in the 2013 IEPR Scoping Memo, PG&E wholeheartedly supports the Commission's decision to analyze the "technical, economic, market, and policy barriers to the use of demand response to support reliability and the integration of renewable resources."[3] However, as described in Section II, PG&E is disappointed that the CEC restricted its analysis to automated, supply-side DR. The CEC should instead consider all types of DR regardless of whether or not it is bid into the wholesale market as supply, or can provide fast response. Demand-side resources, such as conventional DR, energy efficiency, dynamic rates, and permanent load shifting, are essential for meeting the state's reliability needs and integrating renewables at potentially lower cost.

In Section III, PG&E provides specific input on current barriers to DR. PG&E's input on the barriers to DR stems from its assessment of the key drivers of successful DR programs. In summary, PG&E finds that customers are more likely to participate in DR programs if provided a stable regulatory environment, the right incentives, and the right programs. To expand DR in California, the state should ensure that:

- The customer or aggregator can be reasonably certain that both the incentives and chosen program will be available through their planning horizon (stable regulatory environment);
- The economic incentives for customers are commensurate with their opportunity cost for curtailing use (right incentives and cost effectiveness measure); and
- The available DR programs are compatible with the customer's personal, operation, or business needs (right program).

II. CEC SHOULD CONSIDER ALL RELEVANT DEMAND RESPONSE IN THE 2013 IEPR

At the June 17 Workshop, the CEC indicated that it would focus on "automated demand response resources" that "provid[e] fast automated demand response as 'flexible generation-like product.'"[4] This constitutes a much narrower topic then the one outlined in the 2013 IEPR Scoping Memo. Moreover, the change to the scope is counterproductive. If the CEC is interested in utilizing DR for renewable integration, it should seek to include any and all relevant

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[2] Note Advice Letter 4077-E, as modified by 4077-E-B, below:
Randolph, E. (2013, April 2). Proposed Demand Response 2012-2014 Pilot Projects in Compliance with Decision 12-04-045. Retrieved from http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4077-E-B.pdf

[3] McAllister, A. (2013). 2013 Integrated Energy Policy Report Scoping Order (No. 13-IEP-1A). Sacramento, CA: California Energy Commission. Retrieved from http://www.energy.ca.gov/2013_energypolicy/documents/2013-03-07_scoping_order_2013_IEPR.pdf. Pg. 2.

[4] Hungerford, David. 2012. Background: Demand and Load Management Policy in California, website: http://www.energy.ca.gov/2013_energypolicy/documents/2013-06-17_workshop/presentations/01_Hungerford-Background.pdf . Pg. 8.

programs, regardless of whether or not they are automated or bid into the wholesale market as supply. It also needs to consider other related demand side programs like Energy Efficiency, Dynamic Rates and Permanent Load Shifting. Integrating renewable resources will be a significant challenge so all of the numerous and valuable applications of DR and DSM should be considered.

Underlying the Commission's decision appears to be several assumptions regarding DR, namely: 1) only automated DR, bid into the CAISO's capacity market, can or will support reliability and integration of renewable resources; and 2) automated, supply-side DR can and should largely replace retail DR programs. Each assumption is examined below.

A. The assumption that "only automated demand response can support reliability and the integration of renewable resources" is not correct:

Automated DR provides two primary benefits compared to manual DR: 1) it allows a DR resource to be quickly dispatched through an electronic signal; and 2) it allows the system operator to, if the demand resource is capable, continually adjust the amount of load reduction the DR resource provides.

These two characteristics allow automated DR to provide ancillary services, such as regulation, and reserves. In addition, the CAISO could potentially dispatch automated DR to meet daily ramping needs.

However, manual DR can still be dispatched in the wholesale market and, thus, is also able to support the integration of intermittent renewables. For example, manual DR, if structured correctly, can be dispatched during the afternoon and evening peak to reduce the daily ramping need. Additionally, targeting the permanent load shifting resources or time-of-use rates to the morning and afternoon, and evening peaks can flatten the long-term net load curve.

Additionally, including all relevant DR resources is more cost-effective for rate-payers. Automated DR is more expensive than manual DR. In the ancillary services market, the benefits of automated DR—quick, electronic dispatch and adjustability—are worth its premium price. However, integrating renewable resources will require reliability services outside of the ancillary markets, like more day- and hour-ahead energy, and long-term load shaping.

In this context, automated DR loses some of its advantage. Manual DR, at times, could provide the same result without the additional cost. In these instances, manual DR can be more cost effective. Just as generating resources have varying degrees of flexibility, DR programs should have varying degrees of dispatch speed as well.

Finally, as was noted by both the customer and aggregator panels at the June 17 Workshop, DR programs must match a customer's unique needs. Relatively complex programs, like automated DR, are sometimes more difficult and costly for customers and aggregators to utilize. Where automated DR provides a unique benefit, this additional complexity may be justified; however, as described above, if manual DR can provide an equivalent service, this complexity is unnecessary.

B. The assumption that "automated, supply-side demand response can and should largely replace demand-side demand response" is not correct:

At the June 17 Workshop, the CEC, CPUC and CAISO appeared to frame supply-side DR as a superior resource vis-à-vis demand-side DR,[5] the implication being that current DR portfolios should be transitioned to supply-side DR. It may be premature to conclude that DR bid into the market as energy is the next logical step. As explained above, supply-side DR provides unique value. However, demand-side DR can meet key system needs without incurring the additional cost of wholesale market integration.

While automated, supply-side DR can and should play a growing role in California, at this time, it is unclear what the future mix of wholesale and retail programs should be. Bidding DR into the wholesale market is relatively new. Currently, there is virtually no DR participating in CAISO's energy market.

Moreover, as indicated by representatives of PJM, MISO and ERCOT, who spoke at the June 17 Workshop, there is little national experience for supply-side DR. They indicated that most DR does not bid into their energy markets as supply. In PJM, DR plays a major role in maintaining reliability. In the most recent capacity market auction, approximately 75 percent of the DR that cleared the capacity market was reliability DR and was not required to bid into the wholesale energy market. Rather, PJM simply dispatches the DR when needed, one or two hours in advance. For PJM, "bidding into the market" refers to bidding into the 3year-ahead capacity market, not the day-ahead energy market as in California.

Therefore, some amount of reliability DR should always be maintained. There will also be types of DR where bidding into the wholesale market would actually interfere with the purpose of the program. For instance, DR used for distribution-level reliability should be dispatched when utility system operators determine that local conditions warrant it. During a local reliability event, local system conditions will rarely reflect market conditions. Linking the dispatch of any of these programs to the market clearing price would defeat the purpose of the program.

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[5] At the June 17 Workshop, DR programs bid in as energy were considered a supply-side resource and DR that cannot be bid was considered a demand-side resource.

> Finally, while, as described above, automated, supply-side DR provides tremendous value; it also has characteristics that may limit customer adoption. DR relies on customer participation. Automated DR, which requires customers to turn over control of their systems, does not match the personal, operational and business needs of many customers. However, as automation technology evolves and improves more automated DR can be expected.

For the above reasons, PG&E recommends that the CEC examine the barriers to any and all relevant DR programs in the 2013 IEPR. Including the full range of programs will maximize the potential of DR to integrate renewable resources and provides the most value to the state.

III. BARRIERS TO DEMAND RESPONSE IN CALIFORNIA

Per the Commission's invitation, PG&E offers the following assessment of the barriers to DR in California.

A. **Fixing the deficiencies in the CPUC cost effectiveness methodology:** The CPUC cost effectiveness methodology for DR has recognized deficiencies that limit the amount of DR that can pass the cost effectiveness test. There is broad consensus on how to fix those deficiencies. These need to be fixed so that more DR, including fast response DR, will qualify as cost effective.

B. **PG&E needs to be allowed to do a new AMP RFP in late 2013:** The CPUC needs to authorize PG&E to be able to issue a new request for proposal (RFP) for Aggregator Managed Portfolio ("AMP") contracts that would start in 2015. The RFP needs to be issued by late 2013 so that there is sufficient time to obtain bids and get approval by late 2014 so that the aggregators and customers have sufficient time to prepare for 2015. The contracts should be for 5 years so as to provide sufficient time. A 5 year contract timeline will also ensure that customers and aggregators have a stable future to be able to build far more DR products in the future.

C. **Rule 24 needs to be approved and the implementation costs approved:** This will allow non-load serving entities to bid as PDR into the CAISO market.

D. **The 2 percent cap on emergency DR could be reexamined:** As noted in the presentation by PJM and the other regional transmission organization ("RTO"), a very large percentage of their DR is emergency DR. The PJM now has over 4 percent of their peak covered by emergency DR. However, the CPUC has prohibited investor owned utilities ("IOU") from marketing emergency DR. IOUs are limited to a cap of 2 percent of their respective peak loads. This is one of the reasons that other RTOs have more DR than the CAISO.

E. Some CAISO requirements for DR to be in their markets are more restrictive than other RTOs: The CAISO generally has more stringent requirements for wholesale DR than other RTOs. For example, the CAISO generally seeks to have DR bid into the energy market as supply. Other RTOs do not require this. The CAISO has more stringent requirements for DR on telemetry, metering, hours callable per year, trigger, and notification time than is typical in other RTOs. These restrictions limit the amount of DR that could be provided if the requirements were like other RTOs**.**

Also, the presentations by both the CPUC and CAISO at the June 17 workshop indicated that more analysis is needed to determine what DR programs should remain on the load side and which should transition to the supply side. This analysis needs to be done and in the upcoming DR OIR.

F. Provide the right programs: As stated above, DR programs must be compatible with the personal, operation, and business needs of the end-use customer. As noted in the customer panel of the June 17 Workshop, it is important for customers to have simple, easy to implement DR programs. There are many types of customers, with different load curves, risk tolerances, and opportunity costs. To reflect this diversity, a variety of demand-side programs are needed that will provide a matching degree of risk, convenience, and reward. For DR programs, this means having both retail and wholesale programs. DR will be more useful if less expensive retail programs are continued and expanded.

G. Provide a stable regulatory environment: As the customers and aggregators indicated at the June 17 Workshop, developing a new DR program can take anywhere from 18 to 36 months and represents a substantial customer and aggregator investment. Moreover, launching a new program often requires substantial investments for aggregators and customers. Thus, for customers and aggregators to have faith in DR programs they must be relatively stable; when rules are changed they should not be changed abruptly.

IV. CONCLUSION

PG&E thanks the CEC for conducting the June 17 Workshop and appreciates the opportunity to provide comments. PG&E looks forward to continued collaboration with the CEC on this subject in the future.

Sincerely,

/s/

Matthew Plummer

cc: D. Hungerford (David.Hungerford@energy.ca.gov)