Pacific Gas and Electric Company

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Ms. Rajinder Sahota
California Air Resources Board
1001 I Street
Sacramento, CA 95812-2828

Re: February 24 Workshop on Amendments to the Mandatory Reporting and Cap-and-Trade Regulations

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide comments on the Air Resources Board's (ARB) February 24, 2016 workshop on "Potential Revisions to ARB's Regulation for the Mandatory Reporting of Greenhouse Gas Emissions and the Cap-and-Trade Regulation" (workshop). Our comments focus on the following issues:

- ARB Should Further Explore the Feasibility of Changes to the Mandatory Reporting Verification Deadline and Consider Opportunities to Improve the Existing Process
- ARB Should Maintain the Use of Engineering Estimates for Quantifying Flare Gas
- PG&E's Customers Should Not Bear the Compliance Obligation Associated with "Pass-Through" Natural Gas Emissions
- ARB's Proposal that GPEs Report All Imported Power as Specified Will Diminish Californians Investments in Renewable Energy
- Suggestions for Implementation of the Clean Power Plan in California

I. ARB Should Further Explore the Feasibility of Changes to the Mandatory Reporting Verification Deadline and Consider Opportunities to Improve the Existing Process

During the workshop, ARB staff proposed modifying the Mandatory Reporting Regulation (MRR) verification deadline from September 1 to August 1 and along with introducing a new provision requiring reporting entities to certify reports at least 7 days prior to the verification deadline. PG&E is concerned that certifying all of its 14 MRR reports 38 days sooner may not prove feasible under the current program. Before modifying the certification and verification deadlines, PG&E asks that ARB work with compliance entities and verifiers to identify opportunities for streamlining the current MRR process and develop robust solutions. PG&E asks that ARB consider the following recommendations.

Additionally, ARB should revisit the current six-year limitation on a verifier's ability to work for the same reporting entity. PG&E recommends ARB extend the time that a reporter can use the same verification company to 12 years (or 4 compliance periods) for multiple reasons:

- ARB provides an annual determination confirming no Conflict of Interest prior to each verification.
- ARB provides close oversight of each verification body, and the reporting and verification processes are transparent.
- The majority of verifications are performed by 10-15 verification bodies, offering reporting entities little choice in their verifier.
- ARB could provide the public and reporting entities with an assessment of the verifier's performance to address any remaining stakeholder concerns.

The pool of ARB-accredited verifiers has declined annually since the MRR verifications were first required in 2010 and in 2015, 25 companies verified over 500 MRR reports. With its proposal to advance the verification date to August 1, ARB would further exacerbate the present challenges associated with completing the verification process in a timely manner. We are also concerned with the reduction in the pool of accredited verification companies as there may be insufficient skilled personnel available to perform verifications. ARB should explore ways to prevent further decline in the number of verifiers and bring additional verification bodies into the program. For example, ARB could speak with some of the verifiers no longer participating in the MRR to better understand why they made the decision to discontinue providing these services. ARB should also reach out to the current pool of verifiers to hear their perspective on what changes might be needed to ensure the feasibility of any modifications to the verification deadline.

II. ARB Should Maintain the Use of Engineering Estimates for Quantifying Flare Gas

PG&E's natural gas storage fields produce a small quantity of waste gas during the process used to ensure that the natural gas meets the California Public Utility Commission's (CPUC) pipeline-quality standards. This waste gas is destroyed through a thermal oxidization process resulting in a small quantity of greenhouse gas (GHG) emissions. Due to the intermittent nature of the waste gas generation, its variable flow rate, composition and moisture, metering the flows are technically difficult and costly. Therefore PG&E recommends that ARB not modify the current regulation, particularly in the case of reporters who have such waste gas streams.

III. PG&E's Customers Should Not Bear the Compliance Obligation Associated with "Pass-Through" Natural Gas Emissions

PG&E supplies natural gas to a small number of facilities ("Primary Facilities") that pass-through gas to facilities downstream of the PG&E customer meter ("Downstream Facilities"). PG&E reports details regarding the Primary Facilities to ARB annually since those facilities receive equal to or greater than 188,500 MMBtu of natural gas in a calendar year, pursuant to 17CCR§95122(d)(2)(E). However, the pass-through gas is not measured by a PG&E customer meter, and consequently PG&E cannot determine the accuracy of any reported volume. Regardless, ARB includes the volume of the gas delivered to Downstream Facilities as part of PG&E's compliance obligation. The compliance and associated costs for emissions associated with the pass-through gas, for Downstream Facilities, is then borne by PG&E natural gas customers not directly regulated by ARB, an inequitable and inaccurate result. Although the Primary Facilities receive natural gas from PG&E, they do not have a contractual arrangement with PG&E to pass-through a portion of the gas received to Downstream Facilities. To remedy this inequity, Primary Facilities that pass-through gas to the Downstream Facilities should be treated as intrastate pipelines.

To address this issue, ARB needs to resolve the current conflict between the regulatory definition and guidance regarding the definition of an intrastate pipeline. The MRR defines "Intrastate Pipelines" as, "*…Facilities that receive gas from an upstream LDC and redeliver a portion of the gas to one or more adjacent facilities are not considered intrastate pipelines.*" However, Section 3.1.1 of ARB's February 26, 2016 MRR guidance states:

- "*…When gas is delivered to California end-users by an entity other than a natural gas utility, (e.g., a gas producer), the entity that operates the distribution pipeline delivering the gas is considered the supplier and must report under 95122 as an intrastate pipeline.*"
- "*Intrastate Pipelines That Deliver Gas to End-Users: An intrastate pipeline is a distribution pipeline wholly contained within California that is operated by an entity other than a gas utility. Like the natural gas utilities, the operator of an intrastate pipeline that delivers gas to end-users must report pursuant to section 95122(a)(2) of MRR if the total quantity of gas delivered to all entities on their distribution system (i.e., end-users, gas utilities, and/or other pipelines) exceeds the reporting threshold of 10,000 MTCO2e per year. Entities that operate more than one intrastate pipeline must aggregate data from all pipelines in one GHG emissions data report for the entity.*"

Primary Facilities should report their facility emissions, the metered gas receipts, and the gas supplied to Downstream Facilities to ARB. Per 17CCR§95852(a)(1), ARB should assign a compliance obligation to Primary Facilities based on emissions associated with metered deliveries of natural gas.

IV. ARB's Proposal that GPEs Report All Imported Power as Specified Will Diminish Californians Investments in Renewable Energy

PG&E opposes revisions to the MRR to "clarify" that generating providing entities (GPEs) are required to report imported power as specified. By requiring the entity to report such power as specified power, PG&E understands this change would serve to provide the GHG benefit associated with renewable generation to entities that may not have ownership of the renewable or environmental attributes of such generation. As PG&E and the Joint Utility Group outlined in its January 15, 2016 letter concerning the RPS Adjustment, ARB should ensure that only those entities that meet the existing criteria for delivered electricity from a renewable specified source, including the Renewable Energy Credit (REC), may report the electricity as specified power. ARB's proposal would result in financially penalizing Californians who invested in renewable energy to enrich entities such as power traders that do not have title to the carbon attribute of the underlying generation. ARB's proposal would be both harmful to the renewable market and harmful to California ratepayers who would be forced to pay for emissions credits for renewables generation.

V. Suggestions for Implementation of the Clean Power Plan (CPP) in California

We agree with staff's proposal that the CPP backstop is unlikely to be triggered given California's current and planned GHG reduction programs in the electric sector. Since implementation of the backstop program could have disruptive effects beyond the power sector, California's strong CPP compliance position also bodes well for the long-term stability of the AB 32 program. Beyond California's favorable CPP compliance position, we encourage ARB to further reduce the risk of triggering the backstop by designing an Implementation Plan that includes an emission target "glide path" and provides for linkage with other mass-based "trading ready" states. We expand on these ideas below.

Prudent State Plan Design

We recommend that ARB design the emissions glide path for its Implementation Plan to reduce the likelihood that the backstop is triggered. First, ARB should utilize the full existing source cumulative emission budgets provided by EPA in the CPP in its state measures plan (i.e., the cumulative emission budget in the interim period in the state plan should equal the CPP interim budget). The state should not make its CPP compliance task more difficult and increase the chances of triggering the backstop by reducing cumulative budgets in its state plan below CPP-required levels. Second, ARB should consider an interim period "glide path" that allows for relatively greater emissions in the interim step 1 and step 2 periods and relatively fewer emissions in the 2028-29 period, as this would reduce the risk of triggering the backstop caused by temporal variability in emissions within the full interim period (2022-29).

We also recommend ARB pursue opportunities to link with other mass-based "trading ready" CPP programs that develop in other states as another strategy to reduce the risk of triggering the backstop. Net imports of CPP allowances from other states, which would be expected under a linked program, would effectively increase the emissions goal that EPA uses to assess California compliance with the CPP targets and so reduce the likelihood of triggering the backstop.

Backstop Design

To meet EPA's CPP requirements, we believe the backstop must 1) be "composed of federally enforceable emission standards for the affected EGUS that are sufficient to achieve the state CO2 emission goal" and 2) "make up for the shortfall in CO2 emission performance" (CPP, Section VIII.C.3.b). While we appreciate the Staff Proposal's attempt to design a backstop grounded in the existing cap-and-trade program, we are concerned that it may not meet EPA's CPP requirements. Specifically, the set-aside backstop proposal does not appear to ensure that affected EGUs would achieve the CPP-required emission levels if the backstop were triggered. While retiring the set-aside allowances would require real reductions in the cumulative multi-sector WCI program, there is no guarantee that those reductions would come from the electric sector or occur in the backstop period, even if the covered EGUs are required to purchase and retire the set-aside allowances.

One modification to the Staff Proposal that may conform more closely to EPA's CPP requirements would be to require purchase and retirement of CPP allowances (e.g., from the CEIP, Federal Plan allowances, or other state-issued "trading ready" allowances) rather than WCI allowances. This modification would at least guarantee that the shortfall would be made up from within the covered EGU universe of sources. However, even with this modification, it is unclear to us whether this meets EPA's CPP requirements to establish emission standards sufficient to achieve the state emission goals.

Clearly a backstop that included limits on covered EGU emissions at the required statewide levels would meet EPA's CPP requirements. While a narrower EGU-only program in California would naturally provide less flexibility than the multi-sector WCI program, ARB could mitigate this by recognizing other "trading ready" states' allowances for backstop compliance and we encourage ARB to do so. We proposed such an approach in our January 11, 2016 comments to ARB, which we reiterate and summarize here:

> In the event the backstop is triggered, ARB could modify its Cap-and-Trade Program by separating allowances into two categories: (1) allowances that may only be used by EGUs in California regulated under the CPP, and (2) allowances that may be used by covered entities not regulated under by the CPP. In the event of a federal backstop, category 2 allowances may not be used by CPP-affected EGUs for Cap-and-Trade compliance. Banked allowances from previous compliance periods and offsets would also not be available for use by an EGU for compliance during the backstop period.
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> By limiting the allowances available to EGUs to the quantity of emissions required by the CPP, the Cap-and-Trade Program and infrastructure can be used to facilitate a federal backstop. We also recommend that ARB explore backstop flexibility features such as a "trading ready" approach that would allow EGUs in California to utilize allowances from other "trading ready" CPP programs during the backstop period.

State Measures Approach and Modifications to the Cap-and-Trade Program

We support the Staff Proposal framework for California's state plan– a state measures plan relying on California's existing cap-and-trade program. We agree with the Staff Proposal that no changes to the current allocation, banking, and other flexibility mechanisms are required as a result of the CPP. We agree that one of the strengths of this state plan approach is that it allows for the future linkage of California's program with other mass-based trading systems that may develop for CPP compliance. As we described in our January 11, 2016 comment letter, we see linkage to mass-based trading systems that develop for CPP compliance as integral to achieving California's and EPA's emission reduction goals in the most affordable and sustainable manner. We also see this approach as consistent with the environmental goals of the CPP—since emissions from any of these other mass-based programs are capped (e.g., RGGI or mass-based CPP), overall emissions will not increase. To this end, we encourage ARB Staff to work with EPA to ensure technical requirements (e.g., tracking system approval) are in place for California's approval as "ready for interstate trading" so that, once linkage decisions have been made, there are no technical barriers to linkage implementation.

Sincerely,
/s/

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