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Ms. Lucille Van Ommering
California Air Resources Board
Office of Climate Change
1001 I Street
Sacramento, CA 95814

RE: ARB Preliminary Draft Regulation for a California Cap-and-Trade Program

Dear Ms. Van Ommering:

Sempra Energy (Sempra) appreciates the opportunity to submit these written comments concerning the Preliminary Draft Regulation (PDR) for a California Cap-and-Trade Program, issued November 24, 2009 and discussed at a December 14, 2009 workshop. While we have attended many workshops over the past years, it has always been difficult to provide comments without being able to see the interactions of all elements of the proposed cap-and-trade program. Now, having the benefit of the PDR combined with the latest draft of the EAAC Allocation report, we are better able to see the whole picture and provide comments on individual elements from this perspective. We appreciate the thought and detail the ARB staff has put into the PDR.

Sempra's comments reflect the following overarching policy objectives for implementation of AB32:

- Market certainty is critical to avoid discouraging participation in California energy markets and to maximize efficiency and market liquidity in cap and trade markets.
- Accurate long-term price signals and mechanisms to reduce price volatility are needed to encourage long-term investment in GHG-

reducing technologies, avoid punishing early actions, and to recognize that the cost of every ton of carbon emissions is the same, regardless of fuel source or location of those emissions.

- Early action should be rewarded in cap setting and allowance allocation; to do otherwise would send a signal to those that are considering implementation of early actions in California and elsewhere (should California's implementation of AB32 achieve its goal of serving as a model for national GHG regulation).
- CARB's rules should be designed to accommodate seamless transition into a larger regional or Federal program without stranding costs for market participants to avoid discouraging participation in California energy markets and to avoid leakage that could result if businesses seek to leave California to avoid incrementally higher GHG regulatory costs in California.

Overall, the structure and many of the parameters outlined in the PDR seem to fit together well to provide market certainty and accurate long-term price signals for the cost of carbon. The comments below are set forth as responses to the questions posed in the PDR and comments aimed at assuring the proposed cap-and-trade program accomplishes the goals of the State at a reasonable cost. The comments are structured along the same lines as the structure of the PDR.

Subarticle 3. Applicability

- Natural gas-related emissions are distinguishable from electricity-related emissions in that the decisions that impact the level of these emissions are made by end-users, and not by the utilities that provide service to end-users. However, small natural gas consumers are too numerous, and their emissions too small, to effectively participate in a cap and trade program. At the same time, the utilities that serve these customers are not in a position to exert control over their decisions that impact overall emission levels. To address this unique situation, California has implemented extremely effective energy efficiency programs in California for years. President Obama pointed out the effectiveness of these energy efficiency programs earlier last year:

  > *"Think about this. I want everybody to think about this. Over the last several decades, the rest of the country, we used 50 percent more energy; California remained flat, used the same amount, even though that they were growing just as fast as the rest of the country -- because they were more energy efficient. They put in some good policy early on that assured that they weren't wasting energy. Now, if California can do it, then the whole country can do it. Iowa can do it."*

(See, http://www.huffingtonpost.com/william-bradley/obamas-earth-day-energy-d_b_190677.html.)

In light of the proven historical effectiveness of programmatic measures in California's natural gas industry as well as the fact that those that make the actual decisions relative to carbon emissions in the small natural gas consumer market are not the utilities that would be subjected to cap and trade regulation, small natural gas consumers should not be subject to the cap-and-trade program, but should be regulated programmatically in the same manner that has proven extremely effective, and made California a model for the rest of the nation.

At a minimum, the regulation should make participation of this sector in the cap-and-trade program in 2015 conditional on this sector's performance in reducing GHG emissions through programmatic measures. If the sector can achieve the same reduction targets over 2011-2013 as the capped sectors for 2012-2014 on a programmatic basis, programmatic regulation should be allowed to continue for this sector as an alternative to the cap-and-trade program. California's history of success in reducing GHG emissions in this sector through energy efficiency programs should not be ignored, but should be highlighted as an example for the rest of the country. There is no need to design new solutions when energy efficiency has proven successful in reducing this sector's level of GHG. Adding small gas customers through upstream GHG regulation will only create incremental costs without any incremental benefits.

- If the small natural gas sector is covered by the cap-and-trade program, Section 95820(d) should include publically owned natural gas utilities just as the administrative fee regulation includes publically owned natural gas utilities. This change would provide fairness in the same treatment of all natural gas utilities.
- Section 95830(a)(1) should be modified to add <u>all</u> electric generation over 25 MW in addition to electric generation that exceed the threshold of 25,000 MT. The 25 MW limit is consistent with the RGGI requirement for coverage and these units are already part of the current mandatory reporting system. Making this change will not add a large number of new sources(slightly over 50)[1] but avoid any potential impacts on reliability of the electric system in California and avoid A situation in which higher emitting peaking generation could be dispatched ahead of lower emitting resources only because the cost associated with carbon emissions is not recognized in determining economic dispatch for these units. For this peaking type electricity generation, the amount of GHG emissions can vary dramatically from year to year depending on weather and hydro conditions. For example, a 45 MW peaking unit in a normal year may operate 500 hours and

[1] WCI default emission calculator database (lite version); marginal units above 25 MW, with emissions less than 25,000MT. Available at http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/

generate 13,500 MT of CO_2 (at an emissions rate of 0.6 MT/MWh)[2], but in a hot year may operate over a 1,000 hours producing CO_2 above the 25,000 MT threshold. Because exceeding the limit exposes all emissions in the year to the compliance cost as well as for six years in the future, there would be a very large incentive to stay below the threshold. This could create reliability issues in California if the units were approaching the threshold during peak usage periods in late summer and were to choose not to run during these peak periods to avoid exceeding the 25,000 MT threshold.

- Section 95830(a)(2) should be modified to allow ARB to lower the threshold for electricity first deliverers that deliver power to California from non-linked states or provinces. If ARB determines financial or trading intermediaries delivering unspecified power are proliferating to remain below the threshold, it may want to lower the threshold.

Subarticle 4. Compliance Instruments

- Sempra supports approving compliance instruments issued by approved external GHG emissions trading systems as proposed in section 95860. The more compatible the ARB offset criteria are with the criteria of external GHG trading systems, the better will be the ability to create a uniform product and increase the liquidity of the offset market. The approval of other offset providers will better assure an adequate supply of offsets.

Subarticle 6. Allowance budgets

- While the administrative adjustments to the allowance budgets described in section 95910(a) are appropriate to account for changes in scope or thresholds or data errors, revising allowance budgets for "revised estimate of expected emissions levels after the adoption of the allowance budget" should not be allowed absent clear and transparent criteria for making such a decision that prevent market uncertainty among market participants. The prospect of a vague ability to adjust the cap will create undesirable market uncertainty and a reduced incentive for early reductions. Market certainty is critical for the proper functioning of the market. ARB should only adjust the cap based only on objective criteria that the market is able to forecast.
- The voluntary renewable program described in 95910(b) should not lead to *ex ante* withholding from the base budget, but should only be an *ex post* reduction from subsequent quarterly auctions. The added step in the PDR requires the regulatory agency to guess about the correct level of voluntary offsets, a step that is unnecessary to accomplishing the goal of tightening the cap for such voluntary GHG reductions.

[2] Peaking unit emissions rates vary by technology and range from 0.5 MT/MWh to 0.9 MT. Calculated from the WCI default emissions calculator.

Subarticle 7. Surrender Requirements

- Surrender should not take place in two steps (once in the 4th quarter of the year and a second one after verification and true-up in the 3rd quarter of the next year) as proposed in the PDR. There should be only the final true-up. Parties should be paying an estimated amount quarterly or yearly, with only a final accounting after verification. Sempra's proposed 3-year rolling compliance period described later provides an example of the model proposed.

- As described above, Sempra believes small natural gas consumers should not be subject to cap and trade but should be regulated programmatically. But if they are included in the cap-and-trade program, their entry should be deferred until 2015. Further, the regulation should make participation of this sector in the cap-and-trade program in 2015 conditional on this sector's performance in reducing GHG emissions in 2011-2013. If the sector is able to demonstrate that it has achieved the same rate of progress of GHG reductions as is required by the cap-and trade for the capped sectors for 2012-2014, programmatic regulation should be allowed to continue for this sector as an alternative to the cap-and-trade program.

- While Sempra does not take any position on when the transportation industry should be subject to cap and trade, as a general principle, the timing of this transition should not impose any additional costs on other industry sectors.

- AB 32 requires imported electricity be included as an element of statewide greenhouse gas emissions but California should not subject out-of-state entities participating in any other state GHG emission reduction program to double regulation. Section 95950(b)(1) should be modified such that it does not require electricity deliverers to surrender allowances if the electricity is generated in a state which regulates GHG, regardless of whether it is linked. If California is perceived as attempting to impose its GHG regulation on other states that are also seeking to regulate GHG emissions, its program may be challenged in Court and ultimately could be reversed.

- In response to the question identified in Section 95950 (c), the surrender obligation for fuel deliverers should be based on direct emissions for all sectors. This would be consistent with the way in which the allowance budgets and the AB 32 2020 limits were set. Any use of life-cycle emissions will greatly complicate GHG accounting; complicate GHG trading; confuse the measurement of the 2020 AB 32 GHG target, and, where input suppliers are also in California, cause a double counting of emissions reductions.

- Absent specific contract provisions to the contrary, the surrender obligation for fuel delivers needs to recognize the sanctity of contracts. The regulation should not seek to impose costs on a seller that cannot be passed through in an existing contract that does not contemplate regulation of GHG emissions. Imposing such costs on the seller also does not further the goals of AB 32 since the buyer does not receive the price signal and would only serve to discourage participation in

California energy markets, leading to upward pressure on prices and decreased reliability.

- The questions raised in Section 95960 revolve around the timing of a covered entity's surrender obligation. Something akin to the quarterly estimated tax could be employed by ARB where, at regular intervals, a portion of expected allowances would be surrendered by covered entities.
- Sempra recommends ARB consider a rolling compliance period which includes borrowing and banking. For electric generation, frequently subjected to annual fluctuations, a rolling compliance is an important option. If an abnormal period (hydroelectric availability, heat storms, etc) caused a large increase in the facility's level of generation, having several years to true-up could smooth demand for allowances. Additionally, this structure eliminates potential problems which could occur at the end of fixed compliance periods where prices are extremely high (due to inherent demand, and other increases from unanticipated weather-driven energy demand increases and weather driven supply shortages in low emitting resources such as hydro power), immediately followed by a fall in market values for allowances when a new compliance period begins and demand is very low which could lead to highly volatile prices if no borrowing were allowed. ARB could monitor the level of banked and borrowed allowances and offsets to assure there would not be any "cascading shortages."
- The quantitative usage limit for offsets in Section 95970 should be flexibly implemented as proposed by WCI. Aggregate carry-over should be allowed if the 4 percent limit is not fully utilized in a compliance period by covered entities.
- The 49 percent figure in Section 95970 is misleading as labeled (though properly footnoted) since it is not equal to 49% of reductions adopted in the Scoping Plan. It should be stated that it is only 19% of adopted Scoping Plan reductions (reductions from 2012 to 2020 are 67.6 MMT, so 49% equals 33.1 MMT of offsets while the Scoping plan reductions which include economic growth are 174 MMT; 33.1 MMT /174 MMT = 19%).

Subarticle 8. Distribution of Allowance Value

- Sempra has submitted comments to the EAAC supporting an auction of allowances to provide a clear and accurate carbon price signal. In addition, in comments to the EAAC, Sempra supported providing significant allowance value to those that are required to implement CARB's complimentary AB32 implementation measures to partially mitigate the cost impacts of these measures on consumers and to minimize the creation of new infrastructure for distributing allowance value. We pointed out that, in order to maintain the accurate carbon price signals that EAAC's proposed auction process would create, that these auction revenues should be allocated to load serving entities on the basis of sales (as opposed to emissions) in proportion to the obligations load serving entities will have to implement these complimentary measures (e.g., all load serving entities will have to implement an RPS, but only utilities will be required to implement enhanced energy efficiency programs). We noted that the utilities have significant (customer assistance) programs that can be used to distribute allowance value to this segment and RD&D programs that focus on increasing efficiency of fuel use and reducing GHG. Given the likely prospects for a federal program, the ARB should minimize the creation of new infrastructure for the purpose of distributing allowance value that would become stranded with a federal program.

Subarticle 9. Auction Design and Mechanisms for Distributing Auction Proceeds

- Sempra supports ARB's decision to add features to the cap-and-trade program that will better assure reduced price volatility and consistent long-term price signals. The use of a price floor to assure that short-term price fluctuations do not deter long-term investment in GHG reductions by covered entities with either a "hard" or "soft" price floor accomplishing the task. However, developing a reserve that ARB may or may not release to the market on a discretionary basis should be avoided since it would add uncertainty and volatility to the market price. Any unsold allowances should be rolled in the auction the following year or offered on the secondary market at the reserve price.
- Of the options presented by ARB for cost containment, providing for borrowing makes the most sense to smooth short-term volatility. Sempra's proposal for a three year continuous rolling compliance a good example of this approach. Having a trigger to allow more offsets or to release reserve allowances (if any) with clear guidelines as to when such a trigger would be pulled creates market uncertainty and could trigger price volatility because a sudden increase in supply would cause sudden changes in market prices. It could invite market speculation or manipulation to cause a trigger to occur. The ideal would be a price ceiling set sufficiently high to avoid impacting long-term real prices of GHG necessary to attain the goals of AB 32, but to assure short-term price fluctuations do not collapse the market similar to the events of the Electricity Crisis in California. But there is always a concern among parties as to how ARB would determine what is a "high price" and concerns that the price ceiling would be set artificially low so that AB 32 goals are not attained. Given the divergence of views, a price floor and limited borrowing or a three year continuous rolling compliance period is reasonable approach to avoiding short-term price volatility.

Subarticle 11. Trading and Banking

- Section 96080(b) establishes a holding limit calculated as the maximum percentage of outstanding California compliance instruments that may be held by a registrant or a group of affiliated registrants. While this may make sense for some entities to prevent potential market concentration issues, Sempra Energy Companies are regulated by the CPUC in a manner that prohibits coordinated activities between San Diego Gas and Electric, Southern California Gas Company and their energy affiliates with regard to any such compliance instruments. In short, San Diego Gas and Electric, Southern California Gas Company and their energy affiliates must act independently. Under such circumstances the holding limit should apply to each entity independently rather than to the entire corporate family, using revised language as set forth below (proposed revisions are set forth in bold italics):

> "(b) *Holding Limit.* The Executive Officer will establish a market holding limit calculated as the maximum percentage of outstanding California compliance instruments that may be held by a registrant or a group of affiliated registrants.
>
> (1) In making this determination:
>
> > (A) ***In the absence of regulations that prevent coordinated trading activities between affiliates of one corporate family*** holdings of affiliated entities will be considered as being held by a single entity; and
> >
> > (B) beneficial holdings by an agent will be considered as part of the holding of the owner.
>
> (2) A separate limit may be set for financial intermediaries holding instruments beneficially for other entities.

- The regulation should spell out in greater detail in Section 96080 (b) how holding limits be determined. Natural gas fuel providers, which have highly variable winter use depending on the weather, should be allowed to hold significantly more than the expected average year usage to meet these seasonal needs. Similarly, first deliverers of natural-gas-fired electric generation which can be required to make deliveries to meet highly variable summer use depending on the weather and hydro conditions, should be allowed to hold more than their expected average year usage.
- Section 96090 (b) should be modified to allow for use of allowances for one future year. As currently written, it is not consistent with ARB's two part true-up nor with a three year rolling compliance period approach.

Subarticle 12. Linkage to External Trading or Offset Crediting Systems

- Requirements for approval of External Greenhouse Gas Emission Trading Systems, Section 96160, should be modified to distinguish between unilateral and bilateral linkage described in Section 96180. Given that allowances are treated as offsets and subject to a limit for unilateral linking in Section 96180 (a), Section 96160 (b)(5) should be deleted for unilateral linking. All that should be required is that offsets be of similar quality as required by 96160(b)(4). For bilateral linking described in Section 96180 (b), it would seem necessary to have 96160 (b) (5). However, limits on offsets should not be viewed in isolation, but in the context of the stringency of the cap.

Subarticle 13. Offset Credits

- Any change of the offset quantification methodology, described Section 96230, should be applied only on a forward looking basis. A change in the measured reduction should only revise the offsets from particular type projects going forward after the Board-approved change. It should not cause a change in the value of earlier issued offsets.
- Section 96240(c)(5) should be clarified or eliminated. It is not clear what portion of GHG reductions from projects partially funded by public or government grants are not additional. Government entities have significant holdings in the forestry sector, agricultural sector, waste management, and water sectors which are available for potential offset projects. Since "public grant" and "government grant" are not defined, this section could be construed as prohibiting any participation or use of government holdings in offset development.
- Section 96240(h) should be a requirement for "no net harm" as stated in the title rather than "does not cause or contribute to adverse effects on human health or the environment," which could be read as causing "no gross harm."
- Section 96260 (a) (3) should restrict ARB to approving projects in California and adjoining jurisdictions that do not have their own offset approval mechanism. It is better if ARB concentrates on California offsets to assure a supply of those offsets come on to the market as soon as possible and relies on external programs for offsets outside California. Since the cap-and-trade places quantitative limitations on the use of offsets, it does not make sense to set up an elaborate infrastructure for worldwide or even North American offset approval.
- Section 96260 (a) (3) should not impose California levels of additionality for offset approval to avoid creating a dysfunctional market for offsets. ARB should approve project types from external programs so that participants in the cap-and-trade can buy offsets without having to go through a long process with ARB to determine "California additionality." ARB should strive to make it an easy process for buyers, whose main business expertise is not in the nuances of GHG reduction from offsets.
- The ARB proposal in Section 96390 that deficient offset credits must be made whole by purchasers should be changed. Purchasers are not in the business of monitoring and verification and may not be able to tell a "good offset credit" from a "bad offset credit." On the other hand, ARB has that expertise, will be issuing and approving offset types, and has the enforcement authority over offset project developers. ARB should be the one to ensure offsets are of appropriate quality and be the entity to take action against offset developers if the offsets are somehow deficient. If an offset meets ARB's real, verifiable, and permanent criteria then offset buyers should be able to buy from a pool of those ARB-approved offsets. Properly designed offset protocols contain mechanisms for managing reversals.
- A supply of international project-based offsets should be available at the outset of the cap-and-trade program (e.g., a limited amount of CERs issued under the CDM) as discussed in Section 96400(a)(4) which can be phased out over time as a

sufficient pool of sector-based offsets become available. Buyers should be able to purchase offsets beginning at the start of the program.

Subarticle 14. Enforcement and Penalties

- Any penalty provision should not create an incentive to pay the penalty and comply in a subsequent time period. Paying a multiple of, or penalty otherwise calculated on the basis of the market price of the most recent auction in the compliance period should provide an appropriate deterrent.

Subarticle 15. Other Provisions

- To avoid the costs of double regulation, the PDR should clearly provide for a transition and end to the California cap-and-trade program if there is a federal cap-and-trade program. The details of the transition cannot be specified given the lack of clarity about the structure of a federal cap-and-trade or cap-and-dividend program, but the regulation can clearly state that the CA cap-and-trade regulation will end at the time a federal program is effective. And the regulation can clearly state that banked allowances will have value, either for use in the state program through sale to those short of allowances, repurchase by the State, or for use in the federal program. Assurance should be provided that purchasers of California's auctioned allowances will not face the prospect of potential stranded costs should a Federal or broader regional program be implemented.

Thank you for the opportunity to comment.

Sincerely,