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August 11, 2008

Mr. Chuck Shulock
Assistant Executive Officer
Office of Climate Change
Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Sempra Energy Comments Air Resources Board Staff Draft Scoping Plan Appendices

Dear Mr. Shulock:
Sempra Energy submits these attached comments on the Draft Scoping Plan Appendices released by the Air Resources Board (ARB) on July 22, 2008. Please note Sempra Energy's comments are ordered and numbered to coincide with the original July 22 release of the Draft Scoping Plan Appendices and not the PDF pages in the Appendices Sorted by Contents.

Sempra Energy will reserve comment on a number of issues until there is an opportunity to review the data and assumptions used in developing strategies discussed in the Scoping Plan and the Appendices to the Plan.

Thank you for the opportunity to comment on the Draft Scoping Plan Appendices. If you have any questions regarding these observations please contact Taylor Miler at 916-492-4248 or John Fooks at 619-818-2398.

Sincerely yours,

Cc: Edie Chang
Kevin Kennedy

Attachment: Sempra Energy Comments, Air Resources Board Staff Draft Scoping Plan Appendices, August 11, 2008

Sempra Energy Comments

Air Resources Board Staff Draft Scoping Plan Appendices

August 11, 2008

Sempra Energy appreciates the difficulties moving forward with Legislative mandates when all the tools and data needed for evaluation of strategies are not available. We also appreciate the effort of staff to include more information in the Appendices. However, much of the information concerning assumptions and data underlying the cost and reduction calculations that support the Draft Scoping Plan recommendations is still absent. This hampers our ability to provide detailed comments on this subject at this time.

Sempra Energy offers the additional preliminary comments below and looks forward to the opportunity to offer more detailed comments when economic modeling information becomes available later this month.

Specific Measure Comments:

Table 12 – Electricity and Natural Gas – Preliminary Recommendations and Measures under Evaluation – page C-68

Sempra Energy notes two issues related to the qualifying footnote that appears on several tables in the Draft Scoping Plan Appendices.

> "† The net cost of this GHG emission reduction strategy may not include the savings associated with emission control requirements necessary to obtain equivalent reductions of criteria pollutants reduced as a co-benefit, or the additional costs to control increased criteria pollutant emissions as a result of this measure. To the extent feasible, the net cost of emissions controls for criteria pollutants will be evaluated further in measure development."

First, we note that section 38562 (b)(4) specifically addressing co-pollutants, does not mandate that ARB attempt to use AB32, as opposed to existing ARB and local air district authority, to address other air quality concerns. AB32 requires that no increase in toxic or criteria pollutants occur. Concurrently, AB32 will result in opportunities to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions as co-pollutants of GHG. AB32 does not require that ARB use the AB32 to reduce criteria or toxic air pollutants as a prerequisite to adoption of GHG reduction program design approaches. Attempting to load undue consideration to co-pollutant reductions, which will likely accompany GHG reductions in most cases anyway, onto implementation of the AB32 program will dilute the effectiveness of AB32, drive up program costs, dilute the focus of AB32 implementation on cost-effective GHG reduction efforts, result in perverse incentives, tracking problems, and may produce various other unintended consequences.

In addition, to ensure consistency in the economic modeling process the cost of controls should always be compared with on a "cost per unit of reduced emissions of greenhouse gases" as required by the definition of cost effectiveness in section 38505(d). Inclusion of an offsetting dollar "saved" for co-pollutant benefits improperly assumes that the reduction would not have otherwise been required (if the reduction would have otherwise been required, this assumption results in a double counting of co-benefits between AB32 and the other regulations covering the subject co-pollutants). This also distorts the ability to compare cost-effectiveness of GHG reduction measures since this approach elevates "co-pollutants" to a co-equal position in the analysis, contrary to the mandate of section 38562(b)(4). This is all the more likely considering the fact that multiple "co-pollutant" reduction values might be added together (e.g., NOx and PM10) to offset the cost of a GHG reduction activity.

Furthermore there is a potential for double counting when CARB seeks to use co-pollutant benefits to prove that a particular measure is cost effective. For example many local air districts routinely use energy efficiency gains to prove that their own regulatory requirements, (e.g. a NOx emission reduction rule) are cost effective. If a Scoping Plan measure tries to claim energy efficiency gains that have already been used by a local air district to justify a regulatory requirement, this would be double counting. The converse is also true if a local air district should try to prove that a new regulatory requirement will be cost effective using energy efficiency gains already claimed by CARB for an AB32 measure.

(E-2) Increasing Combined Heat and Power – page C-74

The key to the CHP emissions reductions is what efficiencies are assumed (how much of the waste heat is utilized) and what type of resources are being compared. Sempra Energy recommends detailed clarifying comments be included in the Appendices to better identify these assumptions.

Sempra Energy has several clarifying comments on the proposal for adding 4,000 MW of combined heat and power by 2020. The CPUC has initiated an Order Instituting Rulemaking[1] to implement the provisions of AB 1613 requiring utilities to file tariffs and make a standard contract available for the purchase of excess electricity from an eligible CHP. The statute lays out the CHP eligibility requirements, efficiency and maintenance standards required in order to participate in the program. It would be prudent for the ARB to gain experience with the CPUC's program, and to determine the extent in which CHP is actively participating before initiating any additional mandates on CPUC jurisdictional entities.

It is also important to weigh generation dispatch and reliability issues in the analysis of GHG reduction measurers. Mandating utility purchase of all CHP electric output from new or existing CHP facilities could lead to electric system minimum load conditions. While being supportive of efficient CHP, Sempra Energy believes there should be a mechanism in place to mitigate the possibility that CHP mandated purchases could cause minimum load conditions or result in a utility unnecessarily procuring excessive baseload resources.

[1] Order Instituting Rulemaking on the Commission's Own Motion into Combined Heat and Power Pursuant to Assembly Bill 1613

A second issue, with respect to mandated purchases of CHP power, is that not all CHP output is more efficient or has lower GHG emissions than utility provision of power at certain hours of the day. This is the case when nuclear, hydro, or renewable resources are the marginal utility resource providing power. Extensive comments were filed to that effect in the CPUC rulemaking[2]. Also, AB 1613 outlines specific efficiency requirements for "eligible" CHP to participate in the tariff/standard contract.[3] The only way a transmission and distribution system benefit can be realized is when the CHP meets the criteria adopted by the CPUC in D.03-02-068; right time, right place, right size and physical assurance[4].

As previously stated in the related comments, Sempra Energy believes the CHP requirements outlined for IOUs in AB 1613 should apply equally to Publicly Owned Utilities (POUs). POUs should therefore be required to implement an identical CHP program.

(E3) Renewables Portfolio Standard – page C-76

The Scoping Plan Appendices recognize that unlike investor-owned utilities, publically-owned utilities are not obligated to meet current state renewable portfolio

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[2] Sempra Energy Utilities (SEU) comments to the PUC in filed were previously transmitted to the Office of Climate Change by letter to Mr. Charles Shulock, dated June 17, 2008. Detailed comments concerning treatment of CHP are set forth in comments submitted to the PUC in the Joint Proceeding concerning AB32 recommendations, Rulemaking 06-04-009, attached to that letter. See SEU comments dated June 2. 2008, page 13 and following.

[3] *See* AB 1613, Public Utilities Code Section 2843(e) (1) An eligible customer-generator's combined heat and power system shall meet an oxides of nitrogen (NOx) emissions rate standard of 0.07 pounds per megawatt hour and a minimum efficiency of 60 percent. A minimum efficiency of 60 percent shall be measured as useful energy output divided by fuel input. The efficiency determination shall be based on 100-percent load.

[4] "The distributed generation must be located where the utility's planning studies identify substations and feeder circuits where capacity needs will not be met by existing facilities, given the forecasted load growth. The unit must be installed and operational in time for the utility to avoid or delay expansion or modification. Distributed generation must provide sufficient capacity to accommodate SDG&E's planning needs. Finally, distributed generation must provide appropriate physical assurance to ensure a real load reduction on the facilities where expansion is deferred. There is potential that distributed generation installed to serve an onsite use will also provide some distribution system benefit, however, unless it meets the four planning criteria describe by SDG&E, such benefits will be incidental in nature." D.03-02-068 p.18.

standard requirements. Encouragement and goal setting by local governing boards do not carry the force of regulation or statute. As recognized by the California Public Utilities Commission[5] the goals of AB32 would be best achieved if all retail providers of electricity, including IOUs, POUs, ESPs, and CCAs, are subject to the same minimum requirements in the areas of cost-effective energy efficiency and renewables. One of the clearly stated goals in AB32 is that GHG reduction measures be implemented equitably by mandating that CARB "design the regulations, including distribution of emissions allowances where appropriate, in a manner that is equitable."[6] In order for the regulations to be equitable across all sectors it is incumbent for the Scoping Plan to ensure that all reduction obligations are assigned in a cost-effective yet constrained manner which proportionality distributes programmatic costs across all sectors.

Sempra Energy is also concerned that ARB assignment of zero cost to emission reduction measures already mandated (e.g. 20% RPS) is misleading. This method lowers the apparent cost of a 33% renewable target since the cost is only for going from 20% to 33%, but the GHG reductions are in fact going from 2002-2004 level of renewables to 2020 level (33%).

(I-1) Energy Efficiency and Co-Benefits Audit for Large Industrial Sources – page C-102

ARB is considering requiring 54 in-state facilities to conduct an audit of the energy efficiency of individual sources within the facility to determine the potential to reduce greenhouse gases, criteria air pollutants, and toxic air contaminants.

Sempra Energy would like to reiterate that even with the details found in the Appendix regarding the proposed auditing mechanism; it is still unclear and lacking in sufficient detail to comment on its feasibility. Furthermore, this proposed mechanism is a

[5] Rulemaking 06-04-009, 3/13/2008, Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies.
[6] AB 32, Cal. Health & Safety Code § 38562(b)(1).

command and control approach and incompatible with industrial entities subject to a cap having the flexibility and the incentive to determine what GHG reduction measures or alternate compliance mechanisms to adopt. We note that this measure will diminish the potential effectiveness of cap and trade by simultaneously undertaking a program of direct regulation to "help" sources comply with a declining cap.

Also, as noted previously, Sempra Energy is concerned that including the state's natural gas fired power plants could have impacts on system reliability if mandated changes are required during peak demand periods. These clean burning power plants are already subject to significant air quality regulations as well as the proposed cap and trade program under AB32. We recommend ARB weigh the issues of protecting system reliability and meeting the energy demands of California's citizens and exclude power plants from this regulation. Further, since these sources are recommended to be covered by the cap and trade system, there seems to be little likelihood of additional benefits accruing from audits. These sources will already be encouraged to become more efficient, if possible, or to run less because of increasingly scarce allowances, as well as RPS mandates on utilities.

C. Oil and Gas Production – GHG Leak Reduction from Oil and Gas Transmission – page C-113

Sempra Energy reiterates that without access to detailed assumptions it is difficult to understand how the ARB staff has arrived at its estimated capital costs of this measure. Sempra Energy believes that these estimates significantly understate the costs and overestimate the GHG reductions that could be achieved through this measure for natural gas transmission and storage facilities.

Likewise, there is little explanation on how ARB staff estimated a 20-60 percent reduction in fugitive emissions for natural gas transmission. This is a very wide target reduction range to be derived from one program. Many technologies found in the EPA

Energy Star Program have been in use as industry "best practices" for many years. Further, using a simple inventory of equipment to estimate reductions and cost/benefits can be misleading as some infrastructure and equipment are needed for peak period purposes and have zero or very low, annual utilization rates.

Lastly we suspect that the default emission factors are overstated and the fugitive emissions factors for various natural gas transmission equipment is based on an "old" study and needs to be reviewed by industry experts before this measure is adopted and rules passed.

Given this sector's minor contribution to total GHG emissions, Sempra Energy recommends the natural gas (storage, distribution and transmission) sector be excluded, for now, as a strategic reduction sector in the Scoping Plan.

D. General Combustion: Stationary Internal Combustion Engine Electrification – page C-116

Sempra Energy requests the Scoping Plan include IC engines used to power fire pumps to be exempted from an electrification requirement similar to the exclusion of I.C. engines used for emergency power generation.

During the development of the Mandatory Reporting Regulations Sempra Energy noted that the IC engines used to power fire pumps at stationary facilities should be exempted from reporting similar to the exemption allowed for reporting operation of emergency power generation. The reasoning is that infrequent function (usually testing only) is similar among the two sources as are emissions characteristics.

13. Carbon Fee – page C-181

Sempra Energy agrees with ARB that the carbon fee approach does not assure the ability to attain an emissions cap and indeed at this point ARB lacks any evidence or data to assure a price necessary to change consumer habits. In the Appendices, the discussion of an upstream approach does not adequately recognize that a fee taxes imported energy providers, places a hidden tax to users, and increases energy prices to the detriment of consumers' costs. Assuming that downstream GHG emissions could also be subjected to fees, this would double tax consumers and businesses. Adding an energy intensity-based fee to imports runs counter to "global trade" practices, and could significantly impact California's energy imports from Canada.

The upstream approach is a data intensive undertaking that will put a significant administrative burden on designing an accurate intensity model and tracking imported energy sources from their origins. This adds another layer of complexity to what will be very complex regulations for consumers and businesses. Assuming that a climate change regulatory structure will continue through WCI, and national and international programs, there will be other incentives for reducing GHG emissions during the extraction/production and transportation of energy sources.

The Downstream approach, combined with SB1368 for imported electricity, provides for a workable and a sufficiently robust start to implement changes given California's existing energy infrastructure. Once alternative infrastructure and delivery systems and technologies are in place, additional approaches to calculating energy intensity standards for a larger group of sources can be considered.