BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies	Rulemaking 06-04-009

BEFORE THE CALIFORNIA ENERGY COMMISSION

Order Instituting Informational Proceeding AB-32 Implementation: Greenhouse Gases	Docket 07-OIIP-01

Comments of San Diego Gas & Electric Company and Southern California Gas Company Addressing Allowance Allocation Policy, E3 Modeling Results, Programmatic Measures To Reduce Emissions In The Electricity And Natural Gas Sectors, The Joint CPUC/CEC Staff Paper on GHG Regulation for Combined Heat and Power, Flexible Compliance Mechanisms, and Emission Reduction Measures

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June 2, 2008

218321

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I. INTRODUCTION AND BACKGROUND

Pursuant to the April 16th Ruling issued by ALJ TerKeurst and ALJ Lakritz, San Diego Gas & Electric Company ("SDG&E") and Southern California Gas Company ("SoCalGas") (collectively referred to hereafter as "Sempra Energy Utilities" or "SEU") herein provide their comments addressing allowance allocation policy, E3 modeling results, and the May 2, 2008 workshop on programmatic measures to reduce emissions in the electricity and natural gas sectors. These comments and responses are in Section II, below. In addition, in response to the Joint ALJ ruling issued on May 1, 2008 asking that parties' comments on the joint staff paper regarding treatment of Combined Heat and Power ("CHP") facilities under AB 32 be addressed in the comments due on May 27, 2008 SEU's comments on CHP issues are set forth in Section III of these comments. On May 6, 2008 ALJs TerKeurst and Lakritz issued a ruling on flexible compliance mechanisms; These are addressed in Section IV below. Finally, on May 13, 2008 ALJs TerKeurst and Lakritz issued a ruling on emission reduction measures, modeling, and other issues. SEU's comments on these issues are set forth in Section V below. SEU's comments on these four areas are summarized as follows:

Emission Allocation: SEU supports free allocation directly to Load Serving Entities ("LSEs") on an output basis, with appropriate measures to ensure that allowances are made available to the market on a non-discriminatory basis. The proposal is equivalent to an auction approach with Auction Revenue Rights ("ARRs") based on a sales basis using the terminology of the Staff Paper on Options for Allocation of GHG Allowances in the Electric Sector ("Staff Paper").

CHP Issues: SEU supports encouraging the increased efficiency that can occur with appropriately placed and sized CHP applications. If there is increased efficiency, it translates directly into Greenhouse Gas ("GHG") reductions. SEU supports efficient CHP but does not support it being mandated. CHP by necessity must be split into an electricity component and a thermal component based on the California Air Resources Board ("ARB") mandatory reporting requirements in order to provide equal treatment to in-state and out-of-state CHP facilities. SEU supports the methodology for splitting GHG emissions set forth in the Air Resources Board ("ARB") mandatory reporting regulations. Given the split, the electricity portion should be part of the electricity sector and the thermal/mechanical component part of the appropriate sector (industrial or natural gas) depending on the size of the facility.

Flexible Compliance: Reducing GHGs is a long-term proposition; there are no "hot spot" impacts as with criteria pollutants, so flexibility causes no problems with attaining the long-term goals. In addition, electricity is unique in that it cannot be cost effectively be stored and LSEs go to great lengths to ensure reliability of electricity delivery, so flexibility is essential. Therefore, flexible compliance mechanisms that avoid short-term price spikes and eliminate potential reliability problems with no long-term impact on GHG reduction should be encouraged.

Emission Reduction and Modeling: The E3 model is large and complex; therefore SEU believes that there needs to be adequate time allowed in which to verify the model and test sensitivities prior to relying on results of the model for purposes of determining the cost of GHG reductions on LSEs.

II.
RESPONSE TO QUESTIONS RELATED TO EMISSION ALLOCATION METHODS AND POLICIES

The April 16, 2008 ruling asked parties to address the following specific questions[1] related to emission allocation methods and policies:

EA-1. Please explain in detail your proposal for how GHG emission allowances should be allocated in the electricity sector.

SEU supports free allocation directly to LSEs on an output basis, with appropriate measures to ensure that allowances are made available to the market on a non-discriminatory basis. The proposal is equivalent to an auction approach with Auction Revenue Rights ("ARRs") based on a sales basis (using the terminology of the Staff Paper). The output (sales) would be updated at regular intervals such the beginning of each compliance period, and would be adjusted for cumulative Energy Efficiency ("EE") savings. And, as explained later, SEU would support treating on-site use of CHP generation as an LSE in the electric sector. In addition, SEU would support LSEs making allowances available on an output basis to generators supplying the LSE on a fixed price basis under contracts signed prior to AB 32 that do not contemplate a GHG market.

This approach would be most akin to the concept of the "polluter pays." However, the allocation mechanism should not be viewed in isolation, but should be viewed in light of the mandatory measures adopted by the State. Those measures that will bring 60-75 percent of the GHG reductions have not required LSEs with a high GHG-emitting portfolio to undertake any more actions than low emitting LSEs. The E3 modeling reference case shows the total cost change over 2008- 2020 for the lower emitting LSEs to be the same as for higher emitting LSEs (E3, Electric & Natural Gas Modeling, Revised Results and Sensitivities, May 13, 2008, slide 42). Similarly, in the Aggressive Case with expanded EE and 33 percent renewables, the costs are split fairly evenly across LSEs (E3, slide 44). Since these measures allocate the costs of GHG reduction on an output basis, it makes sense to fund

[1] For ease of reference, questions related to emission allowances have been assigned a prefix EA (example: EA-1); questions related to combined heat and power have been assigned a prefix CHP (example: CHP-1); questions related to flexible compliance mechanisms have been assigned a prefix FC (example: FC-1), and questions from the ruling on emission reduction measures, modeling and other issues have been assigned a prefix ER (example: ER-1).

these with allocation of allowances to LSEs on an output basis (or equivalently ARRs based on a sales basis). Allocation of allowances to LSEs on an output basis should be viewed as an appropriate funding mechanism of these mandatory GHG reduction measures.

Further, it should be noted that SEU's proposal would have minimal impact on high emitting LSEs based on the empirical analysis. Staff's Proposed Preferred Auction Proposal as modeled by E3 has 2020 based on a 100 percent auction with ARRs returned to the LSEs on a sales basis. The 2020 result is approximately equal to SEU's proposal of allocation of allowances to LSEs on an output basis. The E3 results show the costs to the higher emitting LSEs are only slightly higher than lower emitting LSEs at a carbon market price of $30 per metric ton (E3, slide 87). Southern California LSEs other than SCE and SDG&E incur one percentage point more in cost increases than PG&E (E3, slide 87).

EA-2. Does any of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your opening comments, raise concerns under the Dormant Commerce Clause? If so, please explain why that allocation option(s) may violate the Commerce Clause, including citations to specific relevant legal authorities. Also, explain if and, if so, how the allocation option(s) could be modified to avoid the Commerce Clause problem.

The dormant "Commerce Clause" of the U.S. Constitution [Article 1, Section 8, clause 3] deals with the powers of the Legislative Branch, and provides that: "Congress shall have Power… To regulate Commerce with foreign Nations, and among the several States, and with the Indian Tribes;." In areas where the U.S. Congress has not acted, the Supreme Court has held that the dormant Commerce Clause implies that states may not discriminate against or unduly burden interstate commerce. However, states still retain their traditional police powers, and courts may balance the need for laws that allow commerce to freely occur between the states against the power of the states to regulate matters that affect the health, safety, and security of their citizens. The allocation options, as long as they are tied to a deliverer point of regulation would only regulate electricity that is generated in, or delivered for consumption in, California. Such a scheme would not regulate any commerce that occurs totally outside of California, and would not regulate extraterritorially in violation of the Commerce Clause. The allocation option chosen should be facially neutral, as between interstate and intrastate commerce, and not have a discriminatory purpose or effect.

EA-3. Does any of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your opening comments, raise legal concerns about whether they involve the levying of a tax and, therefore, would require approval by a two-thirds vote of the Legislature? If so, please explain why that allocation option(s) is taxation, including citations to specific relevant legal authorities. Also, explain if and, if so, how, the allocation option(s) could be modified to avoid such legal concerns.

Since Proposition 13 was adopted in the late 1970s, California has required a supermajority vote (i.e., 2/3 of the Legislature) to adopt any new tax. The California Constitution, Article XIIIA currently requires a 2/3 vote of any changes in state taxes enacted for the purpose of increasing revenues, including by changes in methods of computation. The pure auction option with no revenue return could conceivably be challenged as a new tax, assuming it was adopted as an implementation of AB 32, and if funds from the auction were placed in the State's General Fund.

EA-4. Does any of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your opening comments, raise any other legal concerns? If so, please explain in full with citations to specific relevant legal authorities. Also, explain if and, if so, how, the allocation option(s) could be modified to avoid such legal concerns.

Allocation of allowances to LSEs or equivalent assignment of ARRs based upon emissions rather than on sales is inconsistent with the mandates of AB32 in sections 38562 (b) (1) and (3) to "encourage early action" and give "appropriate credit for early voluntary reductions." Such an allocation would not reward LSEs who have taken early action and instead would protect sources and LSEs who have not undertaken early actions. AB32 also provides in section 38563 that nothing in the act restricts ARB from providing early credits where appropriate.

EA-5. For reply comments: Do any of the allowance allocation options discussed in other parties' opening comments raise concerns under the Dormant Commerce Clause? If so, please explain why that option(s) may violate the Commerce Clause, including citations to specific relevant legal authorities. Also, explain if and, if so, how the allocation option(s) could be modified to avoid the Commerce Clause problem.

This question will be addressed in reply comments.

EA-6. For reply comments: Do any of the options discussed in other parties' opening comments raise legal concerns about whether they involve the levying of a tax and, therefore, would require approval by a two-thirds vote of the Legislature? If so, please

explain why that allocation option(s) is taxation, including citations to specific relevant legal authorities. Also, explain if and, if so, how, the allocation option(s) could be modified to avoid such legal concerns.

This question will be addressed in reply comments.

EA-7. For reply comments: Do any of the allowance allocation options discussed in other parties' opening comments raise any other legal concerns? If so, please explain in full with citations to specific relevant legal authorities. Also, explain if and, if so, how the allocation option could be modified to avoid such legal concerns.

This question will be addressed in reply comments.

EA-8. The staff paper describes an option that would allocate emission allowances directly to retail providers. If you believe that such an approach warrants consideration, please describe in detail how such an approach would work, and its potential advantages or disadvantages relative to other options described in the staff paper. Address any legal issues related to such an approach, as described in Questions 2 – 4 above.

See response EA-1. SEU does not believe there are any legal issues associated with its proposed allocation of allowances to LSEs, or the equivalent of assignment of ARRs to LSEs on a sales basis.

EA-9. Please address the effect that each of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your own or other parties' opening comments, would have on economic efficiency in the economy, and the economic incentives that each option would create for market participants.

SEU's comments regarding the three variations suggested by staff as the "preferred" methods are set forth below:

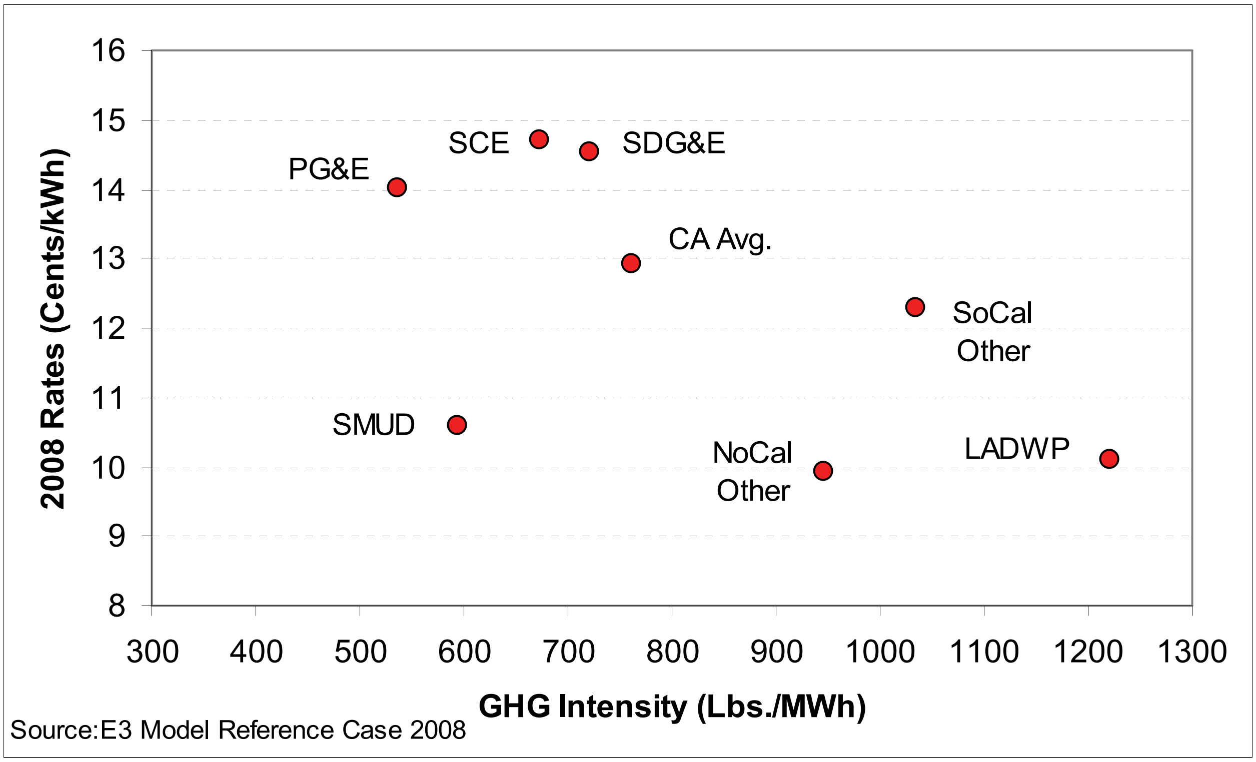
a) An initial administrative allocation of no more than 50% of allowances to deliverers on a historical emission basis. The remaining allowances could be distributed entirely by auction, or through a combination of auctioning and output-based allocation. Share of allowances allocated on an emission basis would decline rapidly in subsequent years.

Any allocation of allowances based on historical emissions fails to reflect the costs imposed on society by first deliverers that have higher GHG emissions and fails to allocate the actual market value associated with lower emissions to first deliverers that have lower emission profiles. This runs counter to the public policies embraced in AB32 and the statutory directives noted in response to Question EA- 3 to recognize early action.

On the other hand, auctions and output based allocation methods both recognize and reflect the full economic cost/value associated with GHG emissions. From that perspective, they both make economic sense. An auction tends to have the highest upward impact on electricity rates, and as such would only be of value to LSE customers to the extent auction revenues are allocated to LSEs. To the extent these revenues are not on a fuel neutral basis, however, such an allocation methodology would fail to impose on LSEs that have high procurement-related emissions, the actual costs associated with their emissions while failing to compensate customers of lower emitting utilities for the costs they have previously incurred, and will continue incurring, to maintain their lower emission levels. To the extent that auction revenues are not allocated to LSEs on a fuel neutral sales basis, they should be directed to research and development activities that are likely to result in future reductions in electricity-related emissions and costs.

Any allocation of auction revenues based on historical emissions would have the effect of rewarding LSEs who delayed reducing their GHG emissions and punishing customers of LSEs that have already incurred significant costs implementing programs and strategies that reduced their emissions. The inequity would result from the fact that, in general, low-emitting LSE rates are higher than those of the higher emitting LSEs, in part as a result of these early actions. Thus, it is clear that the higher emitting LSEs have the "headroom" in rates necessary to incur costs similar to those that have already been realized by the lower emitting LSEs in reducing their emissions. This current in rates and emissions is graphically illustrated below[2]:

[2] Graph is based on E3 model data except to correct SDG&E's rates. SDG&E did not make corrections to other parties' rates or emissions. The emissions are for 2008 and are based on generator assignments that are assumed to be correct but which other parties have not yet verified.



It is also the case that emission reductions become more expensive to attain after lower cost opportunities have been fulfilled. For example, the Investor-owned Utilities ("IOUs") have extensive records of energy efficiency achievements that vastly exceed those of the state's POUs. The challenge is that energy efficiency gains become incrementally more expensive after earlier "lower hanging fruit" has been achieved. As a result, it is reasonable to expect that the GHG reducing strategies (such as energy efficiency) currently available to POUs are, in large part, less expensive to achieve than opportunities currently available to IOUs.

The differences between IOUs and most POUs in this regard are very clear. According to the California Energy Commission ("CEC"), IOU customers spent nearly $1 billion dollars on energy efficiency programs in the 2004-2005 program cycle, while LADWP in the 2006-2007 cycle spent less than $14 million. During this period the IOU's, which provide about 68% of the state's energy, contributed almost 95% of the state's energy efficiency reductions, and SDG&E with 7% of the state's energy contributed 13% of the state's energy efficiency reductions. In contrast, LADWP's contribution to energy efficiency reductions was 0.5%, even though they are 9% of the states energy. (Source: CEC Final Integrated Energy Policy Report ("IEPR"), pgs. 27, 78, 79.) And the mandatory EE measures in the E3 reference case continue this pattern, though to a less extreme extent.[3]

For the forgoing reasons, any allocation of auction revenues should be done in a fuel neutral sales basis, without consideration of historical emissions to most accurately reflect the costs of GHG emissions by LSEs, reward early actions, and to ensure that decisions on behalf of all emitters are made on the basis of the actual costs associated with their emissions.

Finally, annual updates of output may introduce some inefficiency by creating incentives to increase sales. In the SEU proposal, sales are adjusted at set intervals and with adjustment for energy efficiency; these two factors reduce any potential inefficiency while adjusting to account for higher growth in some areas as opposed to other areas.

b) An initial allocation of 90% of allowances to deliverers on an output basis, with the remainder distributed by auction, transitioning to greater percentages of auctioning. Allowances would only be allocated to deliveries from GHG-emitting resources, and this would be done on a fuel-specific basis.

Allocation on a fuel-specific basis fails to impose on first deliverers the actual costs associated with the emission attributes of the sources for the energy they are delivering while minimizing incentives for them to deliver lower emitting resources. In effect, this kind of mechanism would eliminate any near-term incentive for deliverers from lower than average emitting coal resources to change to a lower emitting resource. In comparison, an allocation based on fuel neutral MW output would maximize incentives for first deliverers of ALL high emitting resources to reduce their emissions. It makes no sense, when the overall goal is to minimize carbon emissions, to adopt a cap and trade program that would impose greater costs on lower emitting resources than higher emitting resources. This clearly fails to accurately allocate the costs attributable to GHG emissions to first deliverers and leads to perverse incentives, counter to the overall GHG emission reduction goals behind AB32.

Consider a hypothetical situation involving a first deliverer delivering a higher than average emitting natural gas combined cycle facility with emissions of 1100 lbs/MWh and another first deliverer transporting the output of a lower than average coal-fired generation facility with emissions of 1500 lbs/MWh. Under a fuel-specific allowance allocation market

[3] E3 model, EE tab, cells G13 and I13, show SDG&E undertaking more EE than LADWP though being smaller.

design, the costs imposed on the first deliverer transporting the dirtier generation source would be less than the costs imposed on the first deliverer transporting the lower emitting resource. This is contrary to the intent and directives of AB32. At the same time, deliverers of zero emitting resources that might have a higher capital cost and for which incentives should be maximized would be deprived of part of the value associated with the lower emissions attributable to the energy it delivers. If GHG emissions impose a cost on society, the actual costs of GHG emissions should be imposed on market participants in a way that accurately reflects these costs. The costs of GHG emissions do not depend on what fuel formed the source for the emissions. As a result GHG regulation should not distinguish cost or value on this basis. Any GHG regulation that fails to accurately allocate the costs of GHG emissions on market participants will lead to economically inefficient decisions by market participants.

California now has an opportunity to reward those that enter the market with zero emissions, or extremely low emissions. To fail to take advantage of these kinds of opportunities would be a mistake, and minimize incentives to enter the market with low emissions and/or to reduce high emission profiles that may already exist.

c) Initially auctioning 75% of allowances, with the remaining allowances allocated administratively. The majority of revenues would be recycled to retail providers on a historical emission basis for uses to implement the goals of AB 32, and the revenue allocation would transition slowly to be based on sales over time.

For the reasons identified above, any cap and trade program should be implemented on a fuel neutral basis. An auction could have many of the beneficial features of a fuel-neutral allowance allocation regime in terms of maximizing incentives for high emitters to reduce their emissions, but allocating the majority of revenues to LSEs on the basis of historical emissions would eliminate these benefits, and maximize adverse rate impacts for customers of low emitting LSEs. This would be inequitable and make little economic sense in light of the state's policy objectives. For these reasons a cap and trade program with fuel neutral MW output-based allowance allocation to LSEs would maximize incentives to reduce emissions while minimizing adverse rate impacts to electricity consumers.

Use Of Auction Revenues

EA-10. Describe in detail the method you prefer for returning auction revenues to benefit electricity consumers in California. In addition to your recommendation, comment on the pros and cons of each method listed above, especially regarding the benefit to electricity consumers, impact on GHG emissions, and impact on consumption of electricity by consumers.

All or almost all auction revenues should be allocated to LSEs on a fuel-neutral MW output basis to maximize incentives to reduce emissions, and avoid punishing early actions. Auction revenues that are not allocated to LSEs in this manner should be allocated to research and development activities that demonstrate substantial promise as potential opportunities to reduce future emissions and costs associated with meeting electricity needs in the future.

Staff's Proposal as modified by E3 has 100 percent auctioning of allowances. The majority of revenues would be recycled to retail providers on a historical emission basis for uses to implement the goals of AB 32 at the beginning of the period, and the revenue allocation would transition slowly to be based on sales over time.

This proposal is comparable to allocating allowances to LSEs with a provision to make then available to the market on a non-discriminatory basis. However, SEU disagrees with any allocation of allowances based on historical emissions. As mentioned previously, the costs of the mandated GHG reduction measures is and will be on an output basis. An output based allocation provides funding for the significant cost of those measures that LSE customers are paying. At the same time, all the higher emitting LSEs have significant "headroom" in rates precisely because of the $25-$50 per MWh price advantage of coal over cleaner burning natural gas. (E3, slide 23, assuming natural gas produces 0.5 metric tons less of CO2 per MWh).

In light of the forgoing, it is clear that allocation of allowances, in part or in whole, on the basis of historical emissions would have the result of imposing higher costs on low emitting LSEs compared to higher emitting LSEs. This runs counter to the public policies embraced in AB32 and the statutory directives noted in response to Question EA- 3 to recognize early action. On the other hand, output based allocation to LSEs or the equivalent auction with ARRs assigned on an adjusted sales basis recognizes the early EE actions and renewable mandates and the equal cost burden of mandatory GHG reduction measures implemented during 2012 to 2020.

EA-11. If auction revenues are used to augment investments in energy efficiency

and renewable power, how much of the auction proceeds should be dedicated to this purpose?

Assuming allowances are allocated to LSEs on a fuel-neutral MW output basis, then 100 percent of the revenue that would be coming to LSEs could pay for existing EE programs and renewables procurement already contained within rates and any new mandated ARB emission reduction measures. EE spending or renewables procurement should not be tied to auction proceeds; decisions should be independently made based on regulatory approvals and the market price of carbon. Analysis of the E3 modeling indicates that at $30 per metric ton of CO2, all of the auction revenue would be spent in GHG-reducing activities.[4]

EA-12. If auction revenues are used to maintain affordable rates, should the revenues be used to lower retail providers' overall revenue requirements, returned to electricity consumers directly through a refund, used to provide targeted rate relief to low-income consumers, or used in some other manner? Describe your preferred option in detail. In addition to your recommendation, comment on the pros and cons of each method identified for maintaining reasonable rates.

Auction revenues returned to utilities should be used to reduce overall revenue requirements. This is preferred as compared to a refund or a program designed to provide low income ratepayer relief. In SEU's case, all ratepayers paid for early GHG reduction measures and all ratepayers will participate in paying for currently mandated GHG reduction measures, so all ratepayers should share in the benefit of the allowances allocated to the LSEs (or any auction revenues rights that come back). By reducing overall revenue requirements, flexibility to allocate allowance sale revenues (or ARRs) to pay for existing GHG measures, or to benefit one rate classification or another can be maintained. There is no need to resolve detailed cost allocation issues immediately, and the proper resolution may vary depending on the LSE in question.

EA-13. If you prefer a combination of methods for returning auction revenues, describe your preferred combination in detail.

All or at least a vast majority of revenues from allowances allocated to LSEs on a

[4] Based on the costs in the State in the E3 model for the reference case with zero load growth over 2007-2020 compared to the auction revenues based on $30 per metric ton of CO2 times the E3 modeled emissions for the reference case for 2012-2020.

fuel-neutral MW output basis (or funds from auction revenue rights) should be used to fund GHG reductions of mandatory measures and to off-set rate impacts. The remainder of the allowances or ARRs should be allocated to research and development activities related to low emitting technologies that would help to off-set the cost, reliability, and other impacts to electric customers of GHG regulation.

III.
CHP ISSUES

The staff paper on CHP begins by stating its two main goals, as follows:

> "There are two underlying goals of this staff issue paper. The first is to discuss how CHP should be treated under the AB 32 framework, since CHP units emit GHG, but typically less than conventionally generated electricity. Options include regulating CHP as a separate sector or inclusion in another sector such as electricity, natural gas or industrial. Included here is the question of whether CHP should come under a cap-and-trade framework, if one is adopted by the Air Resources Board (ARB) as part of its AB 32 regulations. Implicit in these questions is the issue of ensuring a level playing field between CHP and other providers of electricity. The second goal of this paper is to discuss whether CHP should be considered a potential emission reduction measure for the purposes of AB 32. If so, then the Commissions may want to consider additional regulatory and policy steps that can be taken to encourage installation of new CHP. The question of whether this is appropriate is discussed in this paper."

SEU's answers to the 24 questions posed in the staff paper are set forth below. However, the short answer to the points raised in the "goals" statement above is as follows:

How CHP should be treated under the AB 32 framework :

SEU fully supports encouraging the increased efficiency that can occur with appropriately placed and sized CHP applications. If there is increased efficiency, it translates directly into GHG reductions. Efficient CHP should be encouraged – but not mandated as an emission reduction measure.

CHP by necessity must be split into an electricity component and a thermal component based on the ARB mandatory reporting requirements in order to provide equal treatment to in-state and out-of-state CHP facilities. Out-of-state CHP (such as Yuma Cogeneration which supplies energy to SDG&E) will only be impacted by AB 32 for the electric portion of its output.

Separating the electric and thermal/mechanical components will allow for equal treatment of the electricity produced.

Given the split of these components, the electricity portion should be part of the electricity sector and the thermal/mechanical component should be part of the appropriate sector (industrial or natural gas) depending on the size of the facility. Under the AB 32 framework, it is important to treat on-site use of electricity equally with electricity purchased from the grid so as to not create artificial disincentives to the development of CHP.

<u>Whether CHP should be considered a potential emission reduction measure:</u>

It is not clear what being designated an "emission reduction measures" would mean for efficient CHP. "Emission reduction measures" are defined in AB 32 and have generally been discussed as mandatory measures adopted by the ARB in regulations. See Health & Safety Code section 38562(a). Our comments below, with respect to CHP, are predicated on the interpretation that "emission reduction measures" is synonymous with mandated measures. It will be difficult to consider CHP as a potential emission reduction measure under this definition. Further, CHP applications vary greatly as to size, technology, fuel, efficiency and location. Given the unique characteristics of CHP applications, an across-the-board determination cannot be made concerning emission reductions. However, SEU does recognize CHP as a very useful efficiency measure that deserves encouragement. Emission reductions from CHP installation should be treated the same as any other emission reduction that may be recognized under AB32.

An appropriately designed carbon market should provide the appropriate price signals to encourage the future development of efficient CHP. Since carbon price will be contained in purchased energy price, and installation of efficient CHP should provide a net reduction in carbon costs, there will be an additional income stream for the owner of the CHP facility to encourage development of CHP.

For all of these reasons, SEU does not support defining CHP as an emission reduction measure under AB32, but does support policies designed to encourage efficient, GHG-reducing CHP.

Treatment of CHP Emissions Under AB 32

CHP-1. Taking into account and synthesizing your answers to other questions in this paper, explain in detail your proposal for how GHG emissions from CHP facilities should be regulated under AB 32.

CHP by necessity must be split into an electricity component and a thermal component based on the ARB mandatory reporting requirements in order to provide equal treatment to in-state and out-of-state CHP facilities. Given the split, the electricity portion should be part of the electricity sector and the thermal component part of the appropriate sector (industrial or natural gas) depending on the size of the facility. In addition, under the AB 32 framework, it is important to treat on-site use of electricity equally with electricity purchased from the grid so as to not create artificial disincentives to the development of CHP.

CHP applications can vary by size of the equipment and by the size of the facility utilizing the CHP equipment. If a cap-and-trade framework is adopted for all electricity deliverers larger than 1 MW and all commercial and industrial facilities producing more than the ARB minimum GHG (currently 25,000 metric tons), then the electric portion of the CHP emissions should be under the cap-and-trade framework if it is larger than 1 MW in size. The thermal or mechanical portion should be under the cap-and-trade as well if it is located in a facility producing more GHG than the ARB minimum reporting standard. SEU supports the methodology for splitting GHG emissions set forth in the Air Resources Board mandatory reporting regulations.

This approach provides consistency in the treatment of out-of-state CHP such as Yuma Cogeneration and in-state CHP facilities. Further, firms that use the electricity produced onsite should be treated as a self-sourced LSE so as to not artificially discourage the installation of efficient CHP. It should be recognized that the increase in onsite GHG is more than offset by reductions elsewhere for efficient CHP.

Smaller CHP would be regulated programmatically and encouraged through programs designed to overcome the first cost barrier.

CHP-2. Should GHG emissions from CHP systems be regulated in one sector? If so, which one? How?

Not Applicable. CHP should not be regulated in one sector.

CHP-3. For in-state CHP systems, should all of the GHG emissions (i.e., all of the emissions attributed to the electricity generation and to the thermal uses) be regulated as part of the electricity sector? If so, for the electricity that is delivered to the California grid, should the deliverer as defined in D.08-03- 018 be the point of regulation? And, what entity(ies) should be the point(s) of regulation for thermal usage and electricity that is not delivered to the California grid if those uses are included in the electricity sector for GHG regulation purposes?

No. If all of the GHG emissions (i.e., all of the emissions attributed to the electricity generation and to the thermal uses) are regulated as part of the electricity sector, then there will be difficulty in treating in-state and out-of-state CHP identically.

CHP-4. For out-of-state CHP systems, how should GHG emissions attributed to the electricity delivered to the California grid be regulated? If part of the electricity sector, should the deliverer of the CHP-generated electricity delivered to the California grid be the point regulation? (These questions are based on our view that, for out-of-state CHP systems, only emissions attributed to electricity delivered to California, and not attributed to other electricity or the thermal output, are subject to AB 32.)

Yes, the deliverer of the CHP-generated electricity should be the point of regulation.

CHP-5. Should CHP units be placed in different sectors based on CHP unit capacity size?

Yes. CHP should be split into an electricity component and a thermal/mechanical component based on the ARB mandatory reporting requirements. If the CHP unit is less than 1 MW and the facility produces less than the ARB reporting minimum, the CHP unit should be subject to programmatic regulations and new CHP promoted through appropriate programs. To the extent that small CHP are below the minimum ARB reporting requirements, monitoring and reporting requirements make it too costly to participate in the cap and trade program. However, consistent with the market incentives that the cap and trade program provides for CHP that meet ARB requirements, small CHP should be allowed to qualify for offsets. If the CHP unit is greater than 1 MW and the facility produces less than the ARB reporting minimum, the CHP unit should be part of the natural gas sector for the thermal/mechanical load and part of the electric sector for the GHG produced by electricity production. If the CHP unit is greater than 1 MW and the facility produces more GHG emissions than the ARB reporting minimum, the CHP unit should be part of the industrial sector for the thermal/mechanical load and part of the electric sector for the GHG produced by electricity production. If the CHP unit is greater than1 MW, and the facility is out-of-state, the electricity produced by the CHP unit should be part of the electric sector.

CHP-6. Should any of the options for assigning the emissions of a CHP unit to one or more sectors be rejected because it might violate the dormant Commerce Clause?

The dormant "Commerce Clause" Article 1, Section 8, clause 3, deals with the powers of the Legislative Branch, and provides that: "Congress shall have Power… To regulate Commerce with foreign Nations, and among the several States, and with the Indian Tribes;…" It does not appear that splitting CHP emissions among sectors would violate the dormant Commerce Clause. However, failure to do so would treat in-state and out-of-state CHP differently, and thus could raise challenges under the Commerce Clause.

<u>Topping Cycle vs. Bottoming Cycle</u>

CHP-7. Should the type of GHG regulation (i.e., cap and trade or direct regulation) be different for a topping-cycle CHP unit versus a bottoming-cycle unit?

No. The GHG emissions should be split based on ARB mandatory reporting requirements in each case. The thermal or mechanical output should be in the natural gas or industrial sector depending on the facility size, and the electricity production should be in the electric sector.

CHP-8. Should the sectors used for GHG regulation be different for topping cycle and bottoming cycle CHP units?

No. The GHG emissions should be split based on ARB mandatory reporting requirements in each case. The thermal/ mechanical related GHG emissions will be greater in the bottoming cycle case, while the electricity component will be larger for the topping cycle. But in each case they are treated consistent with the ARB mandatory reporting protocol split in output.

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Determining Type of CHP Regulation

CHP-9. Should CHP be part of a cap-and-trade program or not? If so, should the entire unit or certain CHP outputs be part of the cap and trade program?

If ARB adopts a cap-and-trade program to implement AB 32, CHP should be split into an electricity component and a thermal/mechanical component based on the ARB mandatory reporting requirements. If the CHP unit is less than 1 MW and the facility produces less than the ARB reporting minimum, the CHP unit should not be part of the cap-and-trade program. If the CHP unit is greater than 1 MW and the facility produces less GHG than the ARB reporting minimum, the CHP unit should be part of the natural gas sector for the thermal load and not part of the cap-and-trade program, but the electric portion should be part of the cap-and-trade program. If the CHP unit is greater than 1 MW and the facility produces more than the ARB reporting minimum, the CHP unit should be part of the cap-and-trade – in the industrial sector for the thermal load and in the electric sector for the CHP electricity production. If the CHP unit is greater than 1 MW, and the facility is out-of-state, the electricity produced by the CHP unit should be part of the cap-and-trade program.

Deliverer and On-Site Generation

CHP-10. Should electricity delivered to the California grid by a CHP unit be regulated under the deliverer point of regulation established in D.08-03-018? Why or why not?

Yes. If there is a cap-and-trade program with a first deliverer point of regulation, all deliverers of power from generation larger than 1 MW need to be included. Excluding CHP from the cap and trade would create cap management difficulties as electric sector emissions would appear to decrease much faster than reality as new CHP is installed. In the E3 GHG modeling aggressive case for CHP, an added 2,410 MW of CHP beyond the base case is comprised entirely of very large combined cycle-like power plants (with some other thermal load) exporting to the grid. (CEC-500-2005-173, p. 2-19) If large combined cycle-like plants were determined to be outside the cap-and-trade by adding an auxiliary thermal application, it may artificially skew the electric sector emissions. Including CHP in an appropriately defined cap and trade system will reward firms for lowering their GHG footprint through addition of efficient CHP.

CHP-11. Should electricity generated by in-state CHP systems for on-site use be subject to the same regulatory treatment as CHP electricity delivered to the California grid? Why or not?

Yes. If there is a cap-and-trade program with a first deliverer point of regulation, all deliverers of power from generation larger than 1 MW need to be included. However, onsite generation should be treated as a self-sourced LSE as well. Otherwise, there is a significant disincentive to installing CHP, since as pointed out in the Staff paper, on-site GHG emissions increase with CHP, while overall GHG emissions decrease. Treating onsite electricity production as a self-sourced LSE would provide allocated allowances or auction revenue rights in the same fashion as LSEs delivering power to the customer. While the firm would now be required to acquire allowances, it would also receive allowances or auction revenue rights for its onsite generation.

Allocation Methodology for CHP

CHP-12. If CHP is regulated in the electricity sector (either as one combined unit or based only on the total electricity output or based only on the electricity delivered to the California grid), do any of the proposed staff allocation options for electricity need to be modified? How?

CHP should be regulated in the electricity sector based on the electricity output of the CHP unit. If so, none of the proposed staff allocation options for electricity need to be modified. However, onsite use of the CHP generation should be treated as a self-sourced LSE and receive allowances (or the auction revenue rights) to not create a disincentive for CHP.

CHP-13. If CHP is treated separately from the electricity sector, but is still included as part of a cap-and-trade program, how should allowance allocation to CHP units be handled?

Not Applicable. CHP should not be treated separately from the electric sector.

CHP-14. If allowances are allocated administratively to CHP units, should the allocations take into account increased efficiency of CHP? If so, how?

SEU does not support free allocation to first deliverers. However, if the ARB were to adopt a free allocation to first deliverers, allocation on an output basis would reward CHP for superior efficiency since the electricity portion of emissions would be less than other fossil generation. If allocations are made to LSEs or auction revenue rights are assigned to LSEs, on-site generation being treated as a self-sourced LSE would provide additional benefits to existing CHP if allocations are based on sales rather than historical emissions.

CHP-15. Are there advantages to having all emissions from in-state CHP regulated as part of the electricity sector under cap and trade (and therefore with the need for only a single set of allowances?) How should this be accomplished?

No. It would create problems by not providing equal treatment to in-state and out-of-state CHP facilities.

CHP as a Potential Emissions Reduction Strategy

CHP-16. Should CHP be considered an emission reduction measure under AB 32? Why or why not?

No. It is not clear what being designated an "emission reduction measures" would mean for efficient CHP. "Emission reduction measures" are defined in AB 32 and have generally been discussed as mandatory measures adopted by the ARB in regulations. See Health & Safety Code section 38565(a). It will be difficult to consider CHP as a potential emission reduction measure under this definition.

Further, CHP applications vary greatly as to size, technology, fuel, efficiency and location. Given the unique characteristics of CHP applications and the fact that not all CHP results in GHG reductions, an across-the-board determination cannot be made concerning emission reductions. However, SEU does recognize CHP as a very useful efficiency measure in most cases that deserves encouragement. Emission reductions from CHP installation should be treated the same as any other emission reduction that may be recognized under AB32.

An appropriately designed carbon market should provide the appropriate price signals to encourage the future development of efficient CHP. Since carbon price will be contained in purchased energy price, and installation of efficient CHP should provide a net reduction in carbon costs, there will be an additional income stream for the owner of the CHP facility to encourage development of CHP.

CHP-17. What is the best approach to regulation of CHP emissions to minimize the potential for disincentivizing new installations of CHP and why is that the best approach?

The best approach to regulation will recognize the efficiency gains of CHP and reward firms that install CHP. There is a direct reward in lower combined electricity and fuel and embedded carbon costs and that would be enhanced under a cap-and-trade system.

CHP-18. Should ARB and/or the Commissions consider policies or programs to encourage installation of CHP for GHG reduction purposes? Why or why not?

The Commissions have adopted the loading order that supports CHP. ARB and/or the Commissions should also consider policies to overcome barriers cited in the CEC CHP Potential Study (CEC-500-2005-173, p. 3-14 and 3-15). The cited barriers were the length of payback and the lack of management interest in the risks of owning and operating energy equipment when it is not the main focus of the business. For reasons such as scarce capital or perceived risk, the investment in the highest efficiency option may be a lost opportunity for energy savings for the 20 to 30-year life of the equipment. LSE-owned or financed projects should be considered to encourage the installation of such cost effective equipment.

LSE-owned or financed major energy systems would overcome the payback barrier and the perceived risk of reliability and performance of energy equipment. The customer would, in concept, pay a surcharge for the CHP equipment that is more than offset by the incremental energy savings they are experiencing resulting in a positive cash flow.[5] Thus, the utility could capture a potentially low cost GHG reduction.

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[5] For utility-owned CHP, the utilities would build, own, operate and maintain the CHP system and investments would be ratebased. Customer-owned systems could involve a buy-down incentive similar to Self Generation Incentive Program ("SGIP"), level 3 (starting in January 1, 2008, CHP were no longer eligible for SGIP incentives), or enhancing the Optional Pricing Tariff ("OPT") and Rule 38 programs that SoCalGas currently administers.

CHP Efficiency Threshold

CHP-19. Should CHP have an efficiency threshold in order to qualify as an emission reduction measure? If so, why?

CHP should not be an emission reduction measure; see discussion above. There should be no minimum efficiency threshold and the decision to implement a CHP system should be left up to the investor or customer.

CHP-20. Which of the proposed methods best achieves the objectives of an efficiency threshold and why is it the best? Is there a superior method not proposed by staff and why is it superior?

SEU does not support treating CHP as an emission reduction measure

CHP-21. What should the minimum efficiency threshold be (in terms of % savings) to qualify as an emissions reduction measure and why is that the appropriate minimum efficiency threshold?

SEU does not support treating CHP as an emission reduction measure

Legal and Regulatory Barriers to CHP

CHP-22. Are there other legal and regulatory barriers to CHP implementation in California that should be considered with respect to GHG regulation? If so, please explain in full with citations to specific relevant legal authorities. Also explain if and, if so, how the barriers could be avoided.

There are significant regulatory barriers related to potential increases in onsite criteria pollutants. Based on AB 32, the legislature desired the retention of these barriers for economic justice considerations. However, the air pollution standards should recognize the reduction in GHG overall for efficient CHP even though GHG associated with the site will increase. The air quality rules should recognize the reduction in GHG associated with the CHP related to reduced generation elsewhere.

CHP-23. Should the Commissions pursue policy or programmatic measures to overcome some of the barriers to CHP deployment?

The Commissions should consider policies to overcome barriers cited in the CEC CHP Potential Study (CEC-500-2005-173, p. 3-14 and 3-15). The cited barriers were the length of payback and the lack of management interest in the risks of owning and operating energy equipment when it is not the main focus of the business. For reasons such as scarce capital or perceived risk, the investment in the highest efficiency option may be a lost opportunity for energy savings for the 20 to 30-year life of the equipment. LSE-owned or financed projects should be considered to encourage the installation of such cost effective equipment.

CHP-24. Would including all of CHP in cap and trade create a disincentive if natural gas is not regulated under cap and trade?

The question as worded is confusing. Large point sources that use natural gas would be covered under the cap and trade. So the question is only relevant for small point sources that have emissions lower than the ARB reporting requirement minimum or are gas-fired electrical generators less than 1 MW. As noted above, SEU proposed that for smaller point sources, only the electric portion greater than 1 MW be under cap and trade. Under this proposal there is no disincentive to install CHP unless onsite usage of the CHP-generated electricity is not treated as a self-sourced LSE or offsets are not allowed in the natural gas sector. Based on the ARB reporting requirements, the benefits of CHP are split between the electric and the thermal/mechanical components. If offsets are not allowed, a portion of the benefit would be lost to the CHP owner.

If the thermal side was included in the cap-and-trade for larger than 1 MW facilities, there would be no disincentive as long as the new thermal load served was calculated based on the prior thermal process or assumed standard efficiency for equivalent thermal equipment (e.g., 80 percent efficient boiler).

IV.
FLEXIBLE COMPLIANCE MECHANISMS

Party Proposals

FC-1. Please explain in detail your comprehensive proposal for flexible compliance rules for a cap-and-trade program for California as it pertains to the electricity sector. Address each of the cost containment mechanisms you find relevant including those mentioned in this ruling and any others you would propose.

In the past, California's environmental regulatory schemes have been supported with proven technology or alternative procedures to reduce the emissions air pollutants. Although some greenhouse emissions can be reduced or eliminated through maintenance, recycling, fuel substitution or other management methods, no technologies exist to control combustion-related carbon dioxide emissions. Accompanying the lack of emission control technical solutions, there are limited short-term options available to meet the challenge of an annual AB 32 emission cap. Since the greenhouse gas emission reduction requirements are long-term goals driven by the cumulative GHG in the atmosphere and there are few short-term control measures, the more flexibility the regulations allow, the greater the opportunity to achieve long-term reductions in the most cost-effective manner possible without creating short-term electricity reliability issues.

It is important that the regulations contain flexible compliance mechanisms to avoid short-term electricity market price volatility and a repeat of the energy crisis. The characteristics of the electricity sector are unique, making the carbon market susceptible to price spikes. Since the demand for allowances by electric generators is highly inelastic (since electric generators can pass on the cost in the market price) and the supply of allowances in the electric sector is also highly inelastic in the short-term (most supply increases will come from long-term investment decisions to increase efficiency or new lower GHG emitting electric generation resources), prices will be volatile without flexible compliance.

Flexible compliance mechanisms for consideration should include a safety-valve mechanism (e.g. allowance price trigger or price ceiling, offramps, etc), sufficient offsets to meet market demand, multi-year compliance periods, banking excess allowances, and limited borrowing against future allocations.

The scope of this Rulemaking is to provide a comprehensive proposal for the electricity sector. However, in the absence of a robust multi-sector cap and trade program, California should <u>not</u> expect in-state resources to try to meet greenhouse gas compliance obligations within an electric-only sector cap and trade program. A multi-sector cap and trade program with the use of offsets will allow resources to capture opportunities realized by others at an efficient and requisite cost. Likewise an efficient cap and trade system which controls costs of energy will benefit low income communities that spend a disproportional amount of resources on energy and fuel. Hence any recommendation proffered by the California Public Utilities Commission to the California Air Resources Board should be for a multi-sector program including transportation and industrial sources and should allow for the use of offsets.

Issues like resource availability (e.g. transmission constraint and hydrologic and renewable status) and weather can cause unpredictable fluctuations in short-term emission characteristics of the electric energy system. A multi-year compliance period and banking will help smooth out short-term fluctuations and most parties are supportive of these measures.

The use of offsets will be important to smoothing price volatility while insuring energy demands are met with adequate resource availability. SEU is aware of the issues of verification of GHG reductions with some offset types, but given the State's preference for trading with other cap-and-trade systems, the use of verifiable offsets approved by other major cap and trade programs, such as the EU ETS or RGGI, should be allowed.

Another flexible compliance mechanism is borrowing. SEU supports limited borrowing by credit-worthy parties or parties who have made GHG reduction investments that are going to come on line in the near future.

FC-1a. Discuss how your proposal would affect the environmental integrity of the cap, California's ability to link with other trading systems, and administrative complexity.

The flexible mechanisms described here would not affect the integrity of the cap over the long-term.

FC-1b. Address how your various recommendations interact with one another and with the overall market and describe what kind of market you envision being created.

The various flexible mechanisms complement one another in providing market price stability and longer-term price signals.

FC-1c. Describe and specify how unique circumstances in the electricity market may warrant any special consideration in crafting flexible compliance policies for a multi-sector cap-and-trade program.

The characteristics of the electric market will likely cause price spikes since there will be a highly inelastic demand for allowances by electric generators who can pass on the cost in the market price and a highly inelastic supply of allowances in the short-term since most GHG reduction will come from long-term lumpy investments (replacing equipment with more efficient equipment or building and operating new lower GHG emitting electric generation resources), investments that take years to move from design to operation. Short-term inelastic supply and demand curves are a recipe for short-term extreme price volatility without flexible compliance options.

FC-1d. If your recommendations are based on assumptions about the type and scope of a cap-and-trade market that ARB will adopt, provide a description of the anticipated market including sectors included, expected or required emission reductions from the electricity sector, and the role that flexible compliance mechanisms serve in the market, e.g., purely cost containment, catalyst for long-term investment, and/or protection against market failures.

SEU assumes that any cap-and-trade program would include other in-state sectors, and would link with other trading programs. The flexible mechanisms are largely to accommodate the nature of the electric sector with inelastic short-term demand and the lag in putting into place longer-term GHG reductions through equipment/resource replacement. In addition, flexible mechanisms should be used to undertake the low cost options first regardless of sector or location.

FC-2. With respect to flexible compliance mechanisms, what should California keep in mind in designing its system when considering the potential transition to regional and/or national cap-and-trade programs in the future? Are there mechanisms that California should avoid or embrace in order to maximize potential compatibility with other cap-and-trade systems?

California is leading the nation with aggressive goals and creative regulatory solutions. Whether an as yet undefined federal program is adopted, it will be important to ensure California businesses are not so disadvantaged that they (and their associated jobs and population) simply migrate elsewhere and leakage occurs. The flexible mechanisms proposed by SEU are all compatible with a future national program.

FC-3. What evaluation criteria should be used in assessing flexible compliance options?

Flexible compliance options should 1) smooth the market price fluctuations that will result because most of the large GHG reductions require replacing equipment, a long-term investment, and 2) integrate the California carbon price with worldwide markets to achieve GHG reductions at the lowest cost.

Market Design and Scope

FC-4. To what extent should the recommendations to the ARB for flexible compliance in the electricity sector depend on the ultimate scope of the multi-sector cap-and-trade program and other market design issues such as allocation methodology and sector emission reduction obligations? Can the Commissions make meaningful recommendations on flexibility of market operations when the market itself has not yet been designed? Why or why not?

Flexible mechanisms are not a good substitute for a broad cap and trade market. The broader and deeper the scope of a cap and trade program, the greater the likelihood of controlling market volatility. The Commission should support all of the suggested mechanisms and recommend a broadly scoped cap and trade program which includes the transportation and industrial sectors.

FC-5. Should the market for GHG emission allowances and/or offsets be limited to entities with compliance obligations, or should other entities such as financial institutions, hedge funds, or private citizens be allowed to participate in the buying and selling of allowances and/or offsets? If non-obligated entities are allowed to participate in the market, should the trading rules differ for them? If so, how?

Prohibiting non-obligated entities from participating in the secondary market may be difficult to enforce since marketer and financial institutions may be acquiring allowances to become new entrant first deliverers. Non-obligated entities could be prohibited from participating in any auctions if there was concern about speculation by entities without obligations.

Price Triggers and Other Safety Valves

FC-6. Should California incorporate price triggers or other safety valves in a cap-and-trade system? Why or why not? Would price triggers or other safety valves affect environmental integrity and/or the ability to link with other systems? Address options including State market intervention to sell or purchase GHG emission allowances to drive allowance prices down or up; a circuit breaker or accelerator which either slows down or speeds up reductions in the emission cap until allowance prices respond; and increasing or decreasing offset limits to increase or decrease liquidity to affect prices. Address how these various strategies would be utilized in conjunction with other flexible compliance mechanisms.

With a broad market and flexible compliance mechanisms, SEU would hope that a price trigger or safety valve mechanism should not be needed. However, given the experience gained in the 2001-2001 energy crisis, unexpected events need to be anticipated. If a price trigger or safety valve is adopted, a safety valve price or alternative compliance payment similar to EU's $100 euros/metric ton, would seem appropriate to provide linkage with the EU.

FC-7. Should California create an independent oversight board for the GHG market?[6] If so, what should its role be? Should it intervene in the market to manage the price of carbon? If such an oversight board were created, how would that affect your recommendations, e.g., would the oversight board obviate the need to include additional cost containment mechanisms and price-triggered safety valves in the market design?

Until the program design for a cap and trade system is further specified, it is premature to recommend a separate market oversight body. This body, which may require legislation, would inevitably further fragment authority for implementing AB32 and should be approached with caution. Section 38599 of AB32 provides the Governor with authority to adjust the applicable deadlines for individual regulations or the state in aggregate in the event of significant economic harm. At this time, SEU supports a function within the ARB to monitor market issues (including transparency and efficiency), flexible compliance mechanisms, and the integrity of the reporting and verification systems. This would provide information and analysis upon which to base recommendations to the Governor in the event market disruptions threaten significant economic harm.

Linkage

FC-8. Should California accept all tradable units,[7] i.e., GHG emission allowances and offsets, from other carbon trading programs? Such tradable units could include, e.g., Certified Emission Reductions, Clean Development Mechanism (CDM) credits, and/or Joint Implementation credits.

California should consider linkage to systems of comparable integrity with similar targets, acceptable measurement protocols, and similar safety valves. GHG is a global problem

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[6] In its Final Report adopted February 11, 2008, the Economic and Technology Advancement Advisory Committee recommends that ARB create a California Carbon Trust that could, among other functions, manage the carbon market in California similar to the way that the Federal Reserve Bank manages interest rates by adjusting the supply of emission allowances and credits through sales and purchases. That report is available at http://www.arb.ca.gov/cc/etaac/etaac.htm.

[7] Tradable units refer to (1) GHG emission allowances that permit emission of a ton of carbon equivalent (CO2E) and (2) offsets that reflect a reduction in GHG emissions of a ton of CO2E, as addressed in Section 2.8 of this ruling. A credit is a broad term used in this ruling to refer to any tradable unit other than a GHG emission allowance issued by California.

and encouraging global action is a desirable property of any cap-and-trade system. California should accept verifiable tradable units from established carbon trading programs. Setting high standards and not accepting offsets or tradable units from other carbon trading programs will make California's program more expensive, may encourage migration of business and result in significant leakage, and would not support action outside of California.

FC-9. If so, what effects could such linkage have on allowance prices and other compliance costs of California obligated entities? Under what conditions could linkage increase or decrease compliance costs of California obligated entities? To what extent would linkage subject the California system to market rules of the other systems? What analysis is needed to ensure that other systems have adequate stringency, monitoring, compliance, and enforcement provisions to warrant linkage? What types of verification or registration should be required?

Linkage to another GHG trading system such as the EU could increase or decrease the price depending on the compliance costs in California versus in the EU or other linked systems. Linkage to the EU would indirectly accept offsets acceptable to the EU and the EU safety valve. The analysis required for linkage and types of verification are important, but given the short decision-making time frame and lack of prior discussion, final recommendations are premature.

FC-10. If linkage is allowed, should it be unilateral (where California accepts allowances and other credits from other carbon trading programs, but does not allow its own allowances and offsets to be used by other carbon trading programs) or bilateral (where California accepts allowances and other credits from other carbon trading programs and allows its allowances and offsets to be used by other carbon trading programs)?

The answer to the question depends on the two trading parties. It would be bilateral unless one party felt its system was more stringent in which case it would not allow credits from the trading partner, but may allow its credits to be used by the trading partner. This issue needs more discussion once the basic framework of the cap-and-trade is set; it seems premature to make recommendations at this point.

FC-11. If linkage is allowed, should allowances and other credits from other carbon trading programs be treated as offsets, such that any limitations applied to offsets would apply to such credits? If not, how should they be treated?

They should be treated the same as offsets. There should be no limitation on the use of offsets.

Compliance Periods

FC-12. What length of compliance periods should be used? Should compliance periods remain the same throughout the 2012 to 2020 period? Should compliance periods be the same for all entities and sectors? Should dates be staggered so that not all obligated entities have the same compliance dates?

The compliance period should be a series of three-year periods for all entities and sectors to allow for variation in weather, hydro, and resource supply conditions in the electric sector and changes in the economy in all sectors. A staggering of the compliance periods for entities would also be beneficial to avoid end-of-compliance-period trading issues. An annual 90% true-up requirement should also be considered to reduce price volatility toward the end of the compliance period.

FC-13. Should compliance extensions be granted? If so, under what circumstances?

Yes, ARB should be able to grant such extensions to deal with unexpected resource and supply issues. The entity should have to show ARB how it will bring itself into compliance. GHG reduction is a long-term issue and there is no need to create short-term crises.

Banking and Borrowing

FC-14. Should entities with California compliance obligations be allowed to bank any or all tradable units, including allowances, offsets, or credits from other carbon trading programs? Should entities that do not have compliance obligations be able to bank tradable units? If so, for how long and with what other conditions? Should allowances, offsets, or credits from other carbon trading programs banked during the program between 2012 and 2020 be recognized after 2020? If the California system joins a regional, national, or international carbon trading program, how should unused banked allowances, offsets, or credits from other carbon trading programs be treated?

All entities that create offsets or have voluntary or rigid compliance obligations should be allowed to bank allowances. Because most sources have long-term operating plans, the banked allowances should be viable into the future past 2020. Since GHG impacts on the environment are cumulative, there is no reason to not allow unlimited banking and the banked allowances to be good indefinitely. There is no potential to create "hot spots" if "too many" allowances are banked.

FC-15. Should limitations be placed on banking aimed at preventing or limiting market participants' ability to "hoard" allowances and offsets or distort market prices?

No. If the cap-and-trade market is so small that an entity could manipulate prices through its banking of allowances, a cap-and-trade market should not be used as a tool for AB 32 compliance.

FC-16. Should entities with compliance obligations be allowed to borrow allowances to meet a portion of their obligation? If so, during what compliance periods and for what portion of their obligation? How long should they be given to repay borrowed allowances? Should there be penalties or interest payments? Should there be other conditions on borrowing, such as limitations on the ability to borrow from affiliated entities? Also address the extent to which borrowing might affect environmental integrity and emission reductions.

Entities which have compliance obligations should be allowed limited ability to borrow. The amount of borrowing and the payback period allowed will vary depending on the length of the compliance period and the characteristics of the borrower. For example, with a single year compliance period, more borrowing should allowed than in a multi-year compliance period since there will be more variability in GHG emissions. Similarly, in the electric sector, peaking units should be allowed more borrowing flexibility than baseload units since their emissions are more variable. Finally, more flexibility should be allowed in the early years since the Commission has acknowledged that major GHG reducing activities such as renewable development including transmission siting is a long process.

Borrowers should be subject to similar creditworthiness requirements as counterparties in energy trades. Borrowing could also be allowed on invested dollars in projects designed to reduce future GHG. For example, dollars spent on a renewable generation unit under construction should allow borrowing up to some percent of the dollars sunk in the project before the project actually comes on line. This could reduce cash flow issues for independent generators expanding their portfolio to include low emissions resources. Finally, borrowing should have some rate of interest attached to it to discourage taking advantage of the time value of money and speculation on prices across compliance periods.

Penalties and Alternative Compliance Payments

FC-17. Should there be penalties for entities that fail to meet their compliance obligations? If so, how should the penalties be set? If not, what should be the recourse for non-compliance?

No, there should be no compliance penalties. Instead, there should be required correction plans approved by the ARB.

FC-18. Instead of penalties, should there be alternative compliance payments? What would be the distinguishing attributes of alternative compliance payments versus penalties? How would the availability of alternative compliance payments affect the environmental integrity of the cap?

SEU prefers borrowing to alternate compliance payments in order to preserve the integrity of the cap. If alternative compliance payments are allowed, they should be based on some multiple of the market price of carbon of the compliance period and should be paid to an entity to purchase offsets or invest in GHG reductions, thus maintaining the integrity of the cap.

FC-19. Would penalties and/or alternative compliance payments allow obligated entities to opt out of the market? Would this add too much uncertainty for other market participants?

As long as the alternate compliance payment or the correction plan bears a reasonable relation to the market price (i.e., well above the market price in the prior compliance period), there should not be a problem. It should be a similar treatment to imbalance fees in gas and electric markets.

FC-20. How should California use the money that would be generated by penalties and/or alternative compliance payments?

See responses to questions FC-17 and FC-18.

Offsets

FC-21. Should California allow offsets for AB 32 compliance purposes?

Yes, as long as the offsets meet the standards set forth in AB 32 (real and verifiable). Global warming is a global issue and it makes no difference where GHG reductions take place. Also, allowing offsets will make linkages with other trading systems possible and the lowest cost GHG reductions will be undertaken. Co-benefits of GHG reductions should not confuse or limit the goals of AB 32 since co-benefits will occur at most locations, both inside and outside California coincidental with GHG reductions.

FC-22. If offsets are permitted, what types of offsets should be allowed? Should California establish geographic limits or preferences on the location of offsets? If so, what should be the nature of those limits or preferences?

Offsets that meet the standards set forth in AB 32 (real and verifiable) and are of equal stringency of the offsets used in other programs should be permitted. Companies in California that have operations in other states and other countries, should be able to increase efficiency in any of their operations or support GHG reduction projects where they do business that have the lowest cost. To not allow such offsets could make the cost of doing business in California higher and simply cause relocation of manufacturing operations and result in GHG emissions leakage.

Further, the WCI states and the federal government are contemplating cap-and-trade programs. If California is desirous of seeing broader programs, it would not make sense to not accept offsets now, but be willing to accept the same reductions later in the trading of allowances when the cap-and-trade expands.

FC-23. Should voluntary GHG emission reduction projects, i.e., projects that are not developed to comply with governmental mandates, be permitted as offsets if they are within sectors in California that are not within the cap-and-trade program? In particular, should voluntary GHG emission reduction projects within the natural gas sector in California be permitted as offsets, if the natural gas sector is not yet in the cap-and-trade program?

The cap-and-trade program is designed to replace mandatory regulations that would otherwise be imposed on entities in the cap-and-trade program. If the natural gas sector is not included initially in the cap-and-trade program, it will instead face new mandates adopted by ARB. Offsets should be allowed after the new ARB mandates are put in place for GHG emissions reductions beyond the new mandates. In addition, no offsets should be allowed for electricification that may occur to meet new mandates. Providing offsets for real and verifiable actions beyond the new mandates will capture some cost-effective GHG reductions that would otherwise be missed.

FC-24. Should there be limits to the quantity of offsets? If so, how should the limits be determined?

No, there should be no limits on the use of otherwise qualified offsets.

FC-25. How should an offsets program be administered? What should be the project approval and quantification process? What protocols should be used to determine eligibility of proposed offsets? Are existing protocols that have been developed elsewhere acceptable for use in California, or is additional protocol development needed? Should offsets that have been certified by other trading programs be accepted? Should use of CDM or Joint Implementation credits be allowed?

ARB should work with existing bodies that have developed protocols to determine these issues in light of AB 32 requirements. CDM and Joint Implementation credits should be allowed, as they are approved through an established and strict regulatory process to verify quality and additionality.

FC-26. Should California discount credits (i.e. make the credits worth less than a ton of CO2e) from some offset projects or other trading programs to account for uncertainty in emission reductions achieved? If so, what types of credits would be discounted? How would the appropriate discount be quantified and accounted for?

No, a metric ton should be a metric ton of reduction. Measurement protocols may calculate a different level of reduction than other jurisdictions might assign to the reduction, but that should be done in the measurement process and should not be called discounting.

Legal Issues

FC-27. Under AB 32, is it permissible for GHG emission allowances from non-California carbon trading programs or offsets from GHG emission sources outside of California to be used instead of GHG emission allowances issued in California? Please consider especially the provisions of Health and Safety Code Sections 3805, 38550, and 38562(a) added by AB 32.

Non-California allowances and offsets do not appear to be precluded by AB 32. Section 38505(k)(2) defines market-based compliance mechanisms broadly to include "greenhouse gas emissions exchanges, banking, credits and other transactions governed by rules and protocols established by the" ARB. Allowance of such transactions can be governed by ARB rules under various circumstances without the credits themselves being *created* by ARB. Sections 38561(b) and 38562(c) allow the ARB to include such systems in its regulatory program. Finally, AB32 directs ARB in section 38564 to “manage greenhouse gas control programs and to facilitate the development of integrated and cost-effective regional, national, and international greenhouse reduction programs”. These provisions are all consistent with allowing reductions from outside California to be used.

FC-28. Do any of the flexible compliance options identified in these questions or discussed in the attachments to this ruling or in your opening comments raise concerns under the dormant Commerce Clause? If so, please explain why that flexible compliance option(s) may violate the Commerce Clause, including citations to specific relevant legal authorities. Also, explain if and, if so, how the flexible compliance option(s) could be modified to avoid the Commerce Clause problem. Address, in particular, whether a policy that limits offsets to only emission reduction projects located in California would raise dormant Commerce Clause concerns.

The dormant “Commerce Clause” [Article 1, Section 8, clause 3] deals with the powers of the Legislative Branch, and provides that: “Congress shall have Power… To regulate Commerce with foreign Nations, and among the several States, and with the Indian Tribes;” In areas where the U.S. Congress has not acted, the Supreme Court has held that the dormant Commerce Clause implies that states may not discriminate against or unduly burden interstate commerce. However, states still retain their traditional police powers, and courts will balance the need for laws that allow commerce to freely occur between the states against the power of the states to regulate matters that affect the health, safety, and security of their citizens. The flexible compliance options, as long as they are tied to a deliverer point of regulation would only regulate electricity that is generated in, or delivered for consumption in, California. Such a scheme would not regulate any commerce that occurs totally outside of California, and would not regulate extraterritorially in violation of the Commerce Clause. The flexible compliance options chosen should be facially neutral, as between interstate and intrastate commerce, and not have a discriminatory purpose or effect. Allowing use of allowances or offsets from out of state does not discriminate. However, prohibiting such use might since the reductions anywhere in the world all have the same effect of mitigating climate change impacts from GHG emissions.

FC-29. Do any of the linkage options identified in these questions or discussed in the attachments to this ruling or in your opening comments raise concerns under

either the Compact Clause or the Treaty Clause of the United States Constitution? If so, please explain why that linkage option(s) may violate one or both of these Clauses, including citations to specific relevant legal authorities. Also, explain if and, if so, how the linkage option(s) could be modified to avoid the Compact Clause and/or Treaty Clause problem.

The "Compact Clause" [Article 1, Section 10, Clause 3] of the U.S. Constitution deals with the powers of the Legislative Branch, and reads as follows: "No State shall, without the Consent of Congress, lay any duty of Tonnage, keep Troops, or Ships of War in time of Peace, enter into any Agreement or Compact with another State, or with a foreign Power, or engage in War, unless actually invaded, or in such imminent Danger as will not admit of delay." The relevant portion of this clause curtails the power of individual states by requiring congressional approval of interstate agreements. However, the Supreme Court applies a functional test that permits interstate agreements without congressional consent so long as the agreements do not undermine the supremacy of the federal government. And, although the text of the Compact Clause might appear broad enough to require congressional consent for all interstate cooperation, no court has ever invalidated an interstate agreement for lack of such consent. Harvard Law Review, Vol. 120, p. 1960 (2007). Thus, adoption of "linkage" proposals by which tradable units from other carbon trading programs may be exchanged with California would appear unlikely to violate the Compact Clause.

The "Treaty Clause" [Article 2, Section 2, Clause 2] of the U.S. Constitution deals with the powers of the President, and (in relevant portion) reads as follows: "He shall have Power, by and with the Advice and Consent of the Senate, to make Treaties, provided two thirds of the Senators present concur; ….". Adoption of "linkage" proposals by which tradable units from other carbon trading programs may be exchanged with California would appear unlikely to violate the Treaty Clause.

FC-30. Do any of the flexible compliance options identified in these questions or discussed in the attachments to this ruling or in your opening comments, raise any other legal concerns? If so, please explain the legal concern(s), including citations to specific relevant legal authorities. Also, explain if and, if so, how the flexible compliance option(s) could be modified to avoid the legal concern(s).

No response at this time.

FC-31. For reply comments: do any of the flexible compliance options identified by other parties in their comments raise legal concerns? If so, please explain the legal

concern(s), including citations to specific relevant legal authorities. Also, explain if and, if so, how the flexible compliance option(s) could be modified to avoid the legal concern(s).

This question will be addressed in reply comments.

V. EMISSION REDUCTION MEASURES

In the May 13th Ruling, parties were asked to respond to the following questions regarding GHG emission reduction measures and annual emissions caps:

ER-1. What direct programmatic or regulatory emission reduction measures, in addition to current mandates in the areas of energy efficiency and renewables, should be included for the electricity and natural gas sectors in ARB's Assembly Bill (AB) 32 scoping plan?

In late 2007, a CPUC Staff workpaper entitled "Greenhouse Gas Emissions Reduction Measures for the Electricity and Natural Gas Sectors Under Consideration as Part of R.06-04-009," was issued as Attachment A to the November 9, 2007 ruling requesting comments on modeling issues. This Staff paper contained preliminary discussion of potential sources of emission reduction above current policy, and identified many technological areas with the potential to make GHG-reduction contributions. The Staff paper contemplated developing renewable power as well as resources that, while not renewable, offer low or zero carbon emissions, and expanding energy efficiency.

Energy efficiency would be particularly effective for point sources that are not of sufficient size to warrant inclusion in an emissions cap and trade program. For these market segments, programmatic measures are likely to be the most cost effective. SEU notes that the electric sector can reach the 1990 levels of GHG emissions with current policies and expanding energy efficiency. The E3 modeling shows that the reference case with mid-EE goals (instead of the reference case EE) will achieve the 1990 level of emissions.

SEU also supports efforts to increase CHP penetration, to increase the supply of renewables as well as low-carbon non-renewable resources, and to promote biomethane use.

ER-2. Are there additional regulations that ARB should promulgate in the context of implementing AB 32, that would assist or augment existing programs and policies for emission reduction measures in the electricity and natural gas sectors?

The more mandatory measures adopted, the less benefit there is from a cap-and-trade system. If the overwhelming majority of reductions are mandated, the Commissions should recommend to ARB that there be no cap-and-trade program.

ER-3. For any non-market-based emission reduction measures for electricity discussed in your opening comments, are there any overlap or compatibility issues with the potential electricity sector participation in a cap-and-trade program? Explain.

The more non-market based emission reduction measures are mandated, the less opportunity there is for cap and trade to open the way to achieving the same reductions at a lower cost. A cap and trade market that is too small also is more likely to exhibit price volatility and raise questions of market power.

ER-4. The scope of this proceeding includes making recommendations to ARB regarding annual GHG emissions caps for the electricity and natural gas sectors. What should those recommendations be? What factors (e.g., potential effectiveness of identified emission reduction measures, rate impacts for electricity and natural gas customers, abatement cost in other sectors, anticipated carbon prices) should the Commissions consider in making GHG emissions cap recommendations? If sufficient information is not currently available to recommend cap levels, what cap-related recommendations should the Commissions make to ARB for inclusion in its scoping plan?

The electric sector and natural gas sector caps should be based on the mandatory measures ARB finds to be cost effective. The cap-and-trade program cap should provide the same level of GHG reduction as would be projected to occur if ARB had adopted the mandatory measures that were deemed cost effective. In this way entities within the cap-and-trade system are not paying more than they would have if the mandatory measures had been adopted. The notion that those subject to the cap under a cap-and-trade should pay for the shortfalls in reductions in other sectors should be rejected.

ER-5. What percentage of emission reductions in the electricity sector should come from programmatic or regulatory measures, and what percentage should be derived from market-based measures or mechanisms? What criteria should be used to determine the portion from each approach? By what approach and in what timeframe should this question be resolved?

It should not be the goal of regulators to determine a specific percentage of market-based measures versus regulatory measures. Instead, regulators should determine the cost effectiveness of each regulatory measure and compare it to the forecasted costs effectiveness of a market based program. Any regulatory measures that are less cost effective than a market based program should not be pursued, unless there is a significant overriding public good that justifies it.

ER-6. Do any of the non-market-based emission reduction measures discussed in your opening comments raise any legal or regulatory concern(s) or barrier(s)? If so, please explain the legal or regulatory concern(s) or barrier(s), including citations to specific relevant legal authorities. Would additional legislation be necessary to overcome any identified legal barrier(s)? Also, explain if and, if so, how the emission reduction measure(s) could be modified to avoid the legal or regulatory concern(s) or barrier(s).

SEU's proposals are intended to be consistent with the statutory meaning of "emission reduction measure" which is defined in Section 38505 (f) as follows:

(f) "Emissions reduction measure" means programs, measures, standards, and alternative compliance mechanisms authorized pursuant to this division, applicable to sources or categories of sources, that are designed to reduce emissions of greenhouse gases."[8]

Note that "emission reduction measures" include "alternative compliance mechanisms" but not "market-based compliance mechanisms".

ER-7. For reply comments: do any of the emission reduction measures identified by other parties in their comments raise legal concerns? If so, please explain the legal concern(s), including citations to specific relevant legal authorities. Also, explain if and, if so, how the emission reduction measure(s) could be modified to avoid the legal concern(s).

This question will be addressed in reply comments.

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[8] "Alternative compliance mechanism is also defined by statute; Section 38505(b):"Alternative compliance mechanism" means an action undertaken by a greenhouse gas emission source that achieves the equivalent reduction of greenhouse gas emissions over the same time period as a direct emission reduction, and that is approved by the state board. "Alternative compliance mechanism" includes, but is not limited to, a flexible compliance schedule, alternative control technology, a process change, or a product substitution.

VI.
MODELING

The May 13th ruling asked that interested parties address the following questions as part of their comments on modeling issues:

ER-8. Address the performance and usefulness of the E3 model. Is it sufficiently reliable to be useful as the Commissions develop recommendations to ARB? How could it be improved?

SEU cannot yet comment on the reliability of the E3 model. It is an extremely large workbook with complex interactions between more than two dozen spreadsheets. While E3 has done a good job of vetting the generation assignment and some other assumptions, there are still numerous assumptions that have not been previously vetted. The entire modeling of EE – how costs are impacted and how sales are changed - is complicated and difficult to comprehend in the model.[9]

SEU has already encountered several coding errors and notes that not all cells reset when changing scenarios.[10] Given the short-time frame at the end that E3 had for making changes, it likely there are additional coding errors. Errors were found in each workshop based on non-intuitive results, and it is likely there are more. Given the relatively short time to analyze and use the model, SEU have not yet formed an opinion on the E3 model's reliability.

As parties continue to use the tool, and coding errors are fixed, it may be useful for the limited purpose of investigating the impact of GHG reduction activities on costs to LSEs in the state. Due to limitations of the model, it does not seem likely that the model will be able to provide, at best, more than extremely rough comparisons of the impacts of alternate carbon allocation mechanisms on the relative costs of LSEs in 2020. Neither the resource choices including EE nor the dispatch of generation is changed in 2020 as a result of changes in the

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[9] It appears that 90 percent of the GHG result in the Stage 1 model occurs with 2.2 billion dollars a year less in utility EE spending in the Stage 2 aggressive case. The original model had a cost of roughly $4 billion a year in EE spending while the revised model has $1.7 billion in spending. In addition the Gas Sector EE result appears to be hard coded with no explanation

[10] For example, any changes to the calibration page does not change the reference case. All results presented use the original E3 reference case for comparison. So even though SDG&E disagrees with the assumption non-generation costs increase by 20 percent with a change in load, it could only show that assumption by changing numerous cell references in the Rates tab.

estimated cost of allowances. While the user can try to guess some of these effects, there will likely be no agreement among parties on what is "correct."

Further, it should be clear that the fact that the model is the electric sector only and the price of allowances must be input (and is not calculated within the model) limits its usefulness for exploring how different elements of a cap and trade mechanism will impact the electric industry in California..

ER-9. Address the validity of the input assumptions in E3's reference case and the other cases for which E3 has presented model results. If you disagree with the input assumptions used by E3, provide your recommended input assumptions.

The input assumptions for generator assignment seem to be correct and the assumptions used in the stage 1 model seemed appropriate; however, SEU has not had time to review all of the model assumptions for stage 2. The substantial changes to the EE component merit further investigation given the large impact on resulting rates. The substantial decrease in emissions coming from the aggressive case energy efficiency and demand response is assumed to lower overall LSE costs by billions of dollars (and billions more than the Stage 1 EE). Non-intuitive results such as the aggressive energy efficiency case showing that the utility costs of these programs may exceed the "total resource cost" creates question of modeling accuracy of these assumptions.

SEU would also note that the beginning rate assumptions for SDG&E are incorrect. The updated GHG Calculator continues to overstate SDG&E's current system average rates as 18 cents per kWh. The correct system average rates for SDG&E based on rates effective May 1, 2008 (AL 1978-E) is 14.528 cents per kWh. This error has an impact in comparing percentage increases in rates, since the same increase in cost will appear to be smaller for LSEs with higher rates. For example, 3 cent/kWh increase will be a 20 percent increase for an LSE with a 15 cent/kWh average rate in 2008, but a 30 percent for an LSE with a 10 cent/kWh rate.

And while it makes no difference to relative results, the assumption that non-generation costs increase by only 20 percent of the load increase is a serious understatement of the impact on LSEs of load growth. SEU recommends a value of at least 75 percent.

ER-10. What evaluation criteria should be used in assessing each issue area in these comments (allowance allocation, flexible compliance, CHP, and emission reduction measures and policies)? Explain how your recommendations satisfy any evaluation criteria you propose.

Allowance Allocation - SEU agree with the criteria outlined in the Staff Paper with the exception of the criteria associated with wealth transfers. Allowance allocation to LSEs on the basis of adjusted sales, or equivalent definition of auction revenue rights, does not create a transfer of wealth since mandatory measures for GHG reduction are funded by LSE customers and higher costs are already being incurred by low emitting LSEs like SDG&E for the use of clean burning natural gas instead of coal

Flexible Compliance – The reduction of GHG is a long-term proposition; there are no "hot spot" impacts as with criteria pollutants. On the other hand, electricity is unique in that it cannot be cost effectively be stored and LSEs go to great lengths to insure reliability of electricity delivery. Therefore, flexible compliance mechanisms that avoid short-term price spikes and eliminate potential reliability problems with no long-term impact on GHG reduction should be encouraged.

CHP - The approach to regulations regarding CHP should 1) encourage the adoption of efficient, GHG-reducing CHP where air quality regulations allow, and 2) discourage adoption of inefficient, inappropriately sized, GHG-increasing CHP.

ER-11. Address any interactions among issues that you believe the Commissions should take into account in developing recommendations to ARB.

No response at this time.

ER-12. In establishing policies regarding allowance allocation, flexible compliance, CHP, and emission reduction policies, what should California keep in mind regarding the potential transition to regional and/or national cap-and-trade programs in the future? Are there policies or methods that California should avoid or embrace in order to maximize potential compatibility with other cap-and-trade systems?

No response at this time.

ER-13. For each issue addressed in your comments, do you have any recommendations about the level of detail and specificity regarding the electricity and natural gas sectors that ARB should include in the scoping plan? Is there enough information in the record in this proceeding to support that level of detail and specificity? What additional information and/or analysis may be needed before ARB finalizes its scoping plan? What determinations regarding the electricity and natural gas sectors should ARB defer for further analysis after the scoping plan is issued? Please be as specific as possible about GHG-related policies for the electricity and natural gas sectors that you recommend be resolved this year, and

policies that you believe should be deferred for further analysis after the scoping plan is issued.

No response at this time.

Respectfully submitted,

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

June 2, 2008

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<u>**CERTIFICATE OF SERVICE**</u>

I hereby certify that pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true and correct copy of **Comments of San Diego Gas & Electric Company and Southern California Gas Company Addressing Allowance Allocation Policy, E3 Modeling Results, Programmatic Measures To Reduce Emissions In The Electricity And Natural Gas Sectors, The Joint CPUC/CEC Staff Paper on GHG Regulation for Combined Heat and Power, Flexible Compliance Mechanisms, and Emission Reduction Measures** on each party named in the official service list in R.06-04-009 and Docket 07-OIIP-01 by electronic service. Those parties who have not provided an electronic address have been served by U.S. Mail, including the State of California, cities and counties in its service territory, by placing copies properly addressed and sealed envelopes and depositing such envelopes in the United States Mail with first-class postage pre-paid.

Executed this 2nd day of June, 2008, at San Diego, California.

/s/ *LISA FUCCI-ORTIZ*______________
Lisa Fucci-Ortiz

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