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.	R.06-04-009 (Filed April 13, 2006)

COMMENTS OF THE DIVISION OF RATEPAYER ADVOCATES ON ALLOWANCE ALLOCATION ISSUES

Pursuant to the October 15, 2007 "Administrative Law Judges' Ruling Requesting Comments and Noticing Workshop on Allowance Allocation Issues" (the October 15 ruling), the Division of Ratepayer Advocates (DRA) respectfully submits the following comments in advance of the November 5, 2007 workshop at which these issues will be further discussed.

I. INTRODUCTION AND SUMMARY RECOMMENDATIONS

DRA's preliminary responses to questions posed by the October 15 ruling are set forth below. The responses may evolve through participation in the November 5 workshop and from reviewing the opening comments of the other parties.

- DRA generally supports allocating some of the allowances administratively in order to ease the transition to a compliance scheme that will make greenhouse gas (GHG) emissions more costly. While the purpose of regulation is to create financial incentives for high-GHG emitters to lower their emissions, initially allocating some of the allowances would further progress towards this goal while at the same time "minimizing costs and maximizing benefits for California's economy."[1]

- The ultimate goal if a cap and trade method of compliance is adopted should be the auction of all allowances, since this is the most economically efficient method of distribution.
- Distribution of allowances, whether by auction or administrative allocation, should recognize early action to reduce greenhouse gas emissions rather than rewarding the use of high carbon fuel.
- Details of the auction's design and revenue distribution are complex and important subjects that merit additional workshops.

The October 15 ruling observed that the California Public Utilities Commission (CPUC) and California Energy Commission (CEC) have not yet determined the ultimate design of the GHG regulatory framework for the electricity and natural gas sector, "including whether a cap and trade system should be implemented."[2] The October 15 ruling requests parties to consider issues related to the distribution of allowances, assuming the adoption of a cap and trade system. Because the CPUC and CEC (Joint Commissions) have not yet determined whether to recommend a "load-based" or "first-seller" point of regulation, the October 15 ruling "includes questions regarding allowance allocations under both structures."[3]

DRA respectfully requests that the Joint Commissions consider another point of regulation, namely, in-state generators only. DRA believes that such a "source-based" approach could comply with Assembly Bill (AB) 32, [4] and may be

[1] California Health and Safety Code, Section 38501(h).

[2] October 15 ruling, p. 3.

[3] Id, p. 3.

[4] Section 38530 of the Health and Safety Code requires the Air Resources Board to adopt regulations that "account for greenhouse gas emissions from all electricity consumed in the state," including import. Section 38505(m) includes within the definition of

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a better point of regulation than either the load-based or first seller approaches, both of which require the use of default emissions factors for out-of-state generation. The "source-based" approach is summarized briefly below.

II. REGULATING IN-STATE SOURCES WOULD ALLOW MORE ACCURATE ACCOUNTING FOR GHG EMISSIONS.

The Joint Commissions are currently considering "load-based" and "first-seller" approaches to regulate emissions from California's electric and natural gas sectors. The load-based and first-seller approaches would regulate GHG emissions from all electricity consumed or produced in California, including imported electricity, using either the load-serving entity or the first seller of power as the point of regulation.

While GHG emissions from imported electricity are significant, comprising "on average about half of the emissions associated with [California's] electricity consumption,"[5] their regulation by California is currently problematic. The emissions associated with imported electricity are in many cases currently unknown.[6] In recognition of this, Decision (D.) 07-09-017 adopted the use of a default factor for reporting emissions associated with unspecified out of state deliveriesThe use of default emission factors for unspecified imports undermines the accuracy of reported emission reductions, and if default emissions factors are used as part of a regulatory compliance mechanism, may encourage gaming and exacerbate the problem of leakage.

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"Statewide greenhouse gas emissions" all electricity delivered to and consumed in California, for purposes of reducing emissions to their 1990 level by 2020. However, the Global Warming Solutions Action of 2006 does not appear to require direct regulation of emissions associated with imported electricity, as long as the goal of reducing emissions to the 1990 level by 2020 is achieved.

[5] D.07.09-017, p. 4.

[6] According to the CEC study "Revised Methodology to estimate the generation resource mix of California electricity imports" (March 2007), for the net total electricity imports in 2005, 44% is unspecified. When broken down further by the originating region, 29% of
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Problems related to the use of default emissions factors could be addressed through the development of a mandated regional GHG emissions tracking system that covers all states from which California imports electricity.[7] This could leverage the ongoing efforts of the Western Climate Initiative (WCI); however the member states of WCI does not currently include Nevada, which exports significant coal power to California.

Until there is accurate information about emissions from imported electricity, and preferably a source-based GHG regulatory system throughout the WECC region that reduces or eliminates incentives to engage in contract-shuffling, DRA recommends that the Joints Commissions consider a two-prong GHG compliance regime for decreasing emission from electricity and natural gas consumption and production:

1) Requiring Load-Serving Entities (LSE) to maximize their use of energy efficiency and meet the target of the Renewable Portfolio Standard (RPS) as mandated in Section 399.11 of the Public Utilities Code. The CPUC is overseeing these requirements of investor-owed utilities it regulates, as directed in the Energy Action Plan. Concurrently, Section 9615 of the Public Utilities Code requires publicly-owned utilities to adopt 10-year targets for energy efficiency savings and report their achievements and program expenditures to the CEC annually.

2) Focusing GHG compliance on in-state entities whose emissions are known and who can be regulated directly by the California Air Resources Board (CARB).

Regulating the GHG emissions from in-state generators would complement the energy efficiency and renewable strategies by reducing the carbon content of

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Southwest imports are unspecified, and 88% of Northwest imports are unspecified.

[7] D.07-09-017 recognized the need to replace default emissions factors with more accurate information as it became available, hopefully before the start of GHG compliance in 2012. D.07-09-017, pp. 42, 44.

in-state electricity supply to the LSEs. Maximizing energy efficiency savings and increasing renewable energy procurement at the retail provider level, while regulating emissions at the generator level would allow the electricity sector to pursue maximum GHG reductions as cost effectively as possible. Leakage would to some extent be mitigated by the Emission Performance Standard mandated by SB1368. Leakage is likely to continue until adoption of either a federal mandate or regional source-based regulation to reduce GHG emissions. In the meantime, adoption of a cap and trade program that focused on in-state sources would be compatible with the adoption of a regional or national cap and trade compliance mechanism.

III. DRA RESPONSE TO THE ALJ QUESTIONS

A. Evaluation Criteria

Q1. Please comment on each of the criteria listed by the MAC. Are these criteria consistent with AB 32? Should other criteria be added, such as criteria specific to the electricity and/or natural gas sectors? In making trade-offs among the criteria, which criteria should receive the most weight and which the least weight?

DRA generally agrees with the principles listed in the October 15 ruling,[8] with a few suggested changes:

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[8] The criteria suggested in the October 15 ruling are:

(a) Reduces the cost of the program to consumers, especially low-income consumers,
(b) Avoids windfall profits where such profits could occur,
(c) Promotes investment in low-GHG technologies and fuels (including energy efficiency),
(d) Advances the state's broader environmental goals by ensuring that environmental benefits accrue to overburdened communities,
(e) Mitigates economic dislocation caused by competition from firms in uncapped jurisdictions,
(f) Avoids perverse incentives that discourage or penalize investments in low-GHG technologies and fuels (including energy efficiency),

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Principles (c) and (f) are similar and should be combined. Additionally, this principle should promote not only the investment in, but also the *transition to,* low-GHG technologies and fuels. DRA recommends the following language to replace Principles (c) and (f):

> *Promotes investment in, and transition to, low-GHG technologies and fuels and strategies (including energy efficiency), while avoiding perverse incentives that would discourage these goals.*

Principles (b), (d), and (g) should be of lower priority than Principles (a), (c), (e), and (f). While these are goals are laudable, they are secondary to AB 32's primary purpose, which is to reduce California's emissions of greenhouse gases as cost effectively as possible.

Principle (h) is less important. A somewhat illiquid market is not necessarily an insurmountable hurdle to meeting the goals of AB 32. For example, the SO_2 market has been fairly illiquid, but the program's goals have nonetheless been exceeded.

B. Basic Options

Q2. Broadly speaking, should emission allowances be auctioned or allocated administratively, or some combination?

An auction is ideal from an economic-efficiency standpoint, because it would allow the true value of the allowances to be realized and paid for by firms who value them. Auctioning allowances is in keeping with the "polluter pays" principle,[9] with the cost of emission distributed among the polluters in the most economic way. This approach also avoids windfall profits that could occur under free allocation of allowances, as explained below.

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(g) Provides transition assistance to displaced workers, and

(h) Helps to ensure market liquidity.

[9] Congressional Policy Brief on Greenhouse Gas Emissions Allowance Allocations, Pew Center on Global Climate Change, preliminary September 2007 version, p. 4.

Additionally, auctioning allowances would reward participants who have taken early actions towards reducing their emissions, because they would need to purchase fewer allowances. Under a load-based regulatory approach, a retail provider can lower its emissions by increasing its energy efficiency savings or increasing its dispatch of zero or low-GHG supply. Under a source-based regulatory approach, non-renewable facilities that have been proactive with improving the plant efficiency would need to buy fewer allowances than they otherwise would need without investments to increase plant efficiency. An added benefit of an auction is that it yields revenues that can be distributed to promote additional climate change research, provide financial assistance to communities that are especially burdened by higher energy costs, and otherwise promote the goals of AB 32.[10]

In contrast, free allocation of allowances is by design a subsidy to mitigate the cost burdens on emitters under a cap and trade program. An emitter can choose to reduce its emissions and sell excess allowances to other firms, or to buy additional allowances to meet its emission target. Under a load-based approach, a regulated LSE or a municipal utility can choose to lower its emissions and pass on the profits of the sold allowances to its customers. Under a source-based regulatory approach, in-state generators will receive allowances to minimize the price differential between in-state generation and out-of-state generation.

Under a first-seller approach, however, free allocation of allowances can result in windfall profits for power marketers. Depending on the basis chosen for distributing free allowances, these firms would receive allowances based on their historic or projected electricity sales. The power marketers have no influence on potential action by out-of-state generators' to reduce emissions. The power

[10] As discussed in response to Question 22, DRA believes that distribution of auction proceeds from an auction to first sellers would need to be carefully crafted to avoid running afoul of the Commerce Clause.

marketers would however, be motivated to engage in contract-shuffling to import low-carbon electricity into California, while simultaneously selling their excess emission allowances at a profit. To avoid this result yet treat all market participants equally, it would be necessary under the first-seller approach to auction all emission allowances from the start of the compliance period.

DRA recognizes that a requirement to purchase all allowances from the beginning of the compliance period could result in financial hardship, especially for carbon-intensive participants. Therefore, DRA recommends a combination of auction and allocation for the load-based and source-based approaches. *Partial* allocation of permits, at least in the initial years of GHG regulation, provides a transition period for participants before moving toward a more efficient, auction-based system.

There is precedent for an auction-allocation combination in other tradable permit programs (the Acid Rain Program, the Virginia NOx Program,[11] the European Union (EU) carbon market, and RGGI). Auctions comprise 2.8 percent, 5 percent, 5 percent, and 25 percent (minimum), respectively, of those allowance markets.

> Q3. If you recommend partial auctioning, what proportion should be auctioned? Should the percentage of auctioning change over time? If so, what factors should be used to design the transition toward more auctioning?

[11] http://ct.gov/dep/lib/dep/air/climatechange/ghgcoalition030907.pdf

DRA recommends that a small but significant proportion (10-20 percent) of allowances be auctioned initially, with this proportion increasing in subsequent years. In the Acid Rain Program, the Virginia NOx program, and the EU carbon market, only 2.8-5 percent of allowances were auctioned, and the vast majority of allowances were given away for free. As a result, auction participation has been fairly low and can therefore be subjected to market power influence (see response to Q7). It is important to establish a robust auction market from the beginning, as the initial auction periods will serve as a learning phase before large portions of allowances are auctioned. Setting aside a significant portion of the allowances to be auctioned will also help to avoid overallocation of emission allowances, as experienced in the EU carbon market.

Initial free allocations of allowances will ease the transition into the cap and trade program. Since free allocations should be used only as a way to ease this transition, they should be phased out over time.

> Q4. How should new market entrants, such as energy service providers, community choice aggregators, or (deliverer/first seller system only) new importers, obtain emission allowances, i.e., through auctioning, administrative allocation, or some combination?

New entrants may participate in the auction, but can also be allocated permits as described under the response to Q12.

C. Auctioning of Emission Allowances

Questions 5 through 9 relate to the auctioning of emission allowances. Designing an allowance auction that meets all its policy objectives and determining the distribution of auction revenue are two complex questions that merit a separate workshop discussion. DRA recommends that the CPUC/CEC hold a separate joint workshop to allow parties more time to fully consider the various auction methods, the issues of market power and the distribution of auction revenues.

Q5. What are the important policy considerations in the design of an auction?

A well-designed auction would encourage widespread participation, create a level playing field for all players, and minimize opportunities for gaming and collusion. These considerations are discussed in more detail below.

(1) Broad market participation Increasing the number of market participants will decrease the opportunities for one or more participants to exercise market power. Clear information about market rules should be shared with all potential responsible participants in order to encourage greater market participation. To the extent possible, market rules should be simple and stable. Stability of market rules would allow market participants to be confident that the rules will remain consistent in the future. Predictability and clarity of communications about market rules should operate to encourage participation in the market.

(2) Level playing field for both large and small market players The ratio of transaction cost to the cost of purchased allowances for a small market player should be similar to that of large bidders. This will avoid creating an artificial barrier for the smaller players to participate in the auction.

(3) Minimize gaming and collusion The market design should penalize gaming and collusion, because those behaviors reduce the effective number of bidders. Market rules that penalize collusion and gaming, in addition to the existence of potential civil and criminal liability, should promote the integrity of the auction process.

(4) Flexible compliance mechanisms In addition to purchase of allowances through the auction, it is important to consider mechanisms that offer "substitutes" for emission allowances, such as offsets. This would increase the elasticity of demand, therefore reducing the potential for any participant to exhibit market power.

Q6. How often should emission allowances be auctioned? How does the timing and frequency of auctions relate to the determination of a mandatory compliance period, if at all?

Infrequent, large auctions may help to lower administrative and transaction costs, but more frequent and smaller allowance auctions would facilitate price transparency that can be used by individual firms in analyzing the cost effectiveness of emission reduction projects. Between auctions, firms are expected to buy and sell allowances through one or more market-based trading mechanisms; it is yet unclear, however, if and how smaller firms will participate in the trading market.

It may be difficult to initially predict how smaller firms will be treated in the marketplace. Whether they face discrimination may depend on whether permits are traded bilaterally or as a commodity, and how much market power the larger participants have. More frequent auctions, at least in the initial years until a trading market is well established, would provide smaller firms a more equal opportunity to purchase allowances at the same cost as other large firms.

The timing and frequency of auctions need not be linked to the compliance period. Nevertheless, holding an auction at the beginning or prior to the first compliance period helps to establish an initial market price for emission allowances.

Q7. How should market power concerns be addressed in auction design? If emission allowances are auctioned, how would the administrators of such a program ensure that all market participants are participating in the program and acting in good faith?

Market power concerns cannot be principally addressed by choosing between an English (ascending price), Dutch (descending price), sealed bid, or any other auction design. Most determinants of market power lie outside of the actual auction. Among other variables, market power relates to the number of bidders, the relative market size of those bidders, and the elasticity of the demand and supply for the marketed product. Generally speaking, market power is inversely proportional to the elasticity of demand and the number of competitors. Demand elasticity, in turn, depends on the availability of supply alternatives. In the case of emission allowance, an example of supply alternatives is offsets.

To ensure that all market participates are participating in the program, and paying the maximum price for the auction item, all participants should be given very clear direction and information about the compliance process. Ambiguity leads to conservatism, which leads to lower prices and fewer bidders. Bidders should have confidence that the rules will remain in place unless serious problems arise.

Market participants are motivated to maximize profit for their own firms, rather than the social good. They do not forego profit for reasons of "good faith" but are motivated to maximize profits to the extent possible. Government regulators need to examine closely the elasticity of both demand and supply in order to better understand the extent to which a single participant or a few market participants could exercise market power. DRA does not currently have enough information to estimate the elasticity of demand, and so does not make specific recommendations on the appropriate number and size of GHG pollution credit bidders. DRA recommends that the CPUC or CEC staff or a contractor undertake such a study.

Q8. What criteria should be used to designate the types of expenditures that could be made with auction revenues (including use to reduce end user rates), and the distribution of money within those categories?

The question of how to distribute auction revenue is as politically complex and difficult as the question of how to allocate free allowances. The choice of a combination approach with partial allowance allocation and partial auction means both questions need to be addressed. The distribution of auction revenue would to some extent depend on the allocation methodology that is ultimately chosen. Output based methodology might lead to hardships to some communities served by high-emitting sources. DRA expects that the criteria for determining distribution of auction revenue would at a minimum include: providing transition assistance to any communities especially hard hit by GHG regulations, financing research and deployment of GHG reduction technologies, and stimulating widespread deployment of public transportation options. However, as discussed in response to Q22, if some of the auction revenue comes from out-of-state entities, such as under the first-seller approach, then distribution of auction revenues for the benefit of in-state actors, would need to be carefully considered for compliance with the Commerce Clause.

Q9. What type of administrative structure should be used for the auction? Should the auction be run by the State or some other independent entity, such as the nonprofit organization being established by the Regional Greenhouse Gas Initiative?

DRA supports an auction run by the state or an independent non-profit entity. The auction administrator should not be a potential participant in the auction, as suggested by PG&E.[12] Any potential auction participant would have a conflict of interest if it is also assigned as the auction administrator.

D. Administrative Allocation of Emission Allowances

DRA answers questions 10-20 below. The October 15 ruling requested that each question be separately answered for a load-based system and for a first-seller approach. However, as explained in DRA's response to Q2, allocation of allowances is not appropriate under a first-seller approach. Therefore, DRA answers the questions below from a load-based or source-based regulatory

[12] Comments of PG&E on Market Advisory Committee Recommendation of "First Seller" Regulation of GHG Emissions under AB32, August 6, 2007, p. 35.

perspective. Unless otherwise noted, the answers do not change under either of these two approaches.

DRA believes that "updating" is not necessarily a separate allocation methodology, but rather a variation of other allocation options. Updating would not apply to a grandfathering method, since historic emissions cannot be updated. However, an allocation methodology based on fuel input or electricity output could be updated periodically to reflect changes to the fuel mix or electricity output from the initial allocation. In contrast, a non-updating methodology would keep the initial allocation proportions throughout subsequent allocations.

Also, DRA will not discuss benchmarking as a separate methodology. A benchmarking method based on emissions per kWh, for example, is ultimately equivalent to an output-based method. Allowances cannot be granted simply based on a standard emission rate of, say, 1 pound of carbon per kWh. Since electricity output is variable, such an allowance methodology would not ensure that the total emissions from all emitters comply with the overall carbon cap. Using a benchmarking method with an overall cap would require the calculation of an average emission rate based on the state's total electricity output. This method is essentially the same as allocating allowances to capped entities in proportion to their electricity output. (See Appendix A for sample calculations.) In the response below, DRA focuses its allocation discussion for an output-based allocation methodology.

> Q10. If some or all allowances are allocated administratively, which of the above method or methods should be used for the initial allocations? If you prefer an option other than one of those listed above, describe your preferred method in detail. In addition to your recommendation, comment on the pros and cons of <u>each</u> method listed above, especially regarding the impact on market performance, prices, costs to customers, distributional consequences, and effect on new entrants.

Allocation should be based on electricity sales (on a kWh basis), with periodic updates. For example, if a participant represents 5 percent of the total sales of electricity in California, it would receive 5 percent of the allowances that are allocated for that time period. Under a load-based system, the allocation would be based on the sum of electricity sales *and* energy efficiency savings to encourage the load serving entities (LSEs) to maximize energy efficiency savings. (See response to Question 18.)

The allocation should be updated every 3 to 5 years. Periodic updating is important in order to reflect changes such as population growth and departing load. DRA believes that annual updates are not necessary, as population generally does not change dramatically in a single year, and short-term, weather-related peaks and valleys in demand would be smoothed out over a 3-5 year time period. Also, if a "true-up" mechanism is adopted (as described below), then changes from the sales forecast will be taken into account. Therefore, annual updating would simply create an unnecessary administrative burden without adding significant value to the process.

Allocation based on electricity sales has several benefits. First, it would not penalize retail providers that serve large populations, or areas with higher energy demand due to climate factors or the presence of energy-intensive facilities. Second, it would encourage participants to employ low-carbon energy sources to meet their demand. Furthermore, if the allocation is based on the sum of electricity sales *and* energy efficiency savings, this methodology would encourage LSEs to maximize energy efficiency savings. From a source-based regulatory standpoint, an output-based allocation methodology encourages plant owners to improve the plant efficiency to lower GHG emissions per unit of output.

There are four separate types of data to use in this allocation approach:

(1) Historical Sales. For each auction period, estimated output would be based on the average of the previous 3-5 year period. For example, for a 2012-2014 time period, permits could be allocated based on average

output for 2009-2011. This method would be relatively easy, and based on actual data. However, it would not account for changing factors such as population growth, departing load, etc. A participant with high population growth could be allocated too few permits, and a participant who loses customers during the 2012-14 period would receive too many. This drawback could be mitigated by frequent updates, but in any given allocation period, some participants could experience windfall profits or shortage of allowances. Additionally, participants might be incented to increase their output during the initial base years in order to be allocated more allowances.

(2) Actual Output. Allowances could be awarded at the end of the compliance period, based on actual output. This method has the advantage of avoiding forecast errors. However, this approach would undermine the development of a market-based trading mechanism for participants during the compliance period due to the uncertainty of the number of allowances allocated to each participant.

(3) Projected Sales. Using historical sales data and projected changes in factors such as population growth, participants could project what their sales would be for the upcoming allocation period. Projections would be submitted prior to the allocation. The advantage of this method is that it accounts for changing factors that impact sales. Since generators and retailers project their electricity sales for other business reasons, this method would not create any additional administrative burden for them. However, participants might be incented to inflate their projections, thereby undermining the accuracy of this method.

(4) Projected Sales with a "True-Up." The Projected Sales approach could be implemented with a "true-up" at the end of the allocation period. As part of the true-up process, initial allocations would be adjusted based on actual sales data. Participants that were allocated too many permits up front will have to surrender those extra permits (which means they must buy back those extra permits if they had been sold to another firm). Entities initially allocated too few permits would be given

> additional permits. The advantage of this method is that an initial allocation allows for trading throughout the period, and gives participants an idea of how many permits they will ultimately have. Meanwhile, the true-up will adjust for changes that were initially unforeseen. Since participants should know what these changes are as they happen, they should be able to predict to some degree whether they will owe or be owed permits at the end.

DRA tentatively supports using an output-based allocation methodology that utilizes projected sales with an end-of-period true-up to reflect actual sales (#4 above).

The October 15 ruling noted that grandfathering or "Other" measures could also be used to allocate permits. DRA does not support grandfathering, as this method rewards high emitters; it is also a much more costly approach overall.[13] Grandfathering *could* be used to reward recent energy efficiency and renewable energy efforts, if allowances are awarded based on emissions from a past date, such as 1990. In this situation, facilities that have made improvements since 1990 could potentially gain by selling excess allowances. The flip side of this, however, is that using a base year so far back will not reflect other variable factors that affect demand, such as population growth. For facilities or retail providers that have entered the industry since 1990, permits would need to be allocated on some other basis.

Various other measures could be used to allocate permits. Each of these methods would need to be individually assessed; however, the October 15 ruling suggests population or cost of compliance as possibilities. DRA does not support either of these methods. Awarding permits based on pounds of carbon dioxide per capita again simply rewards carbon-intensive energy rather than giving appropriate credit for early action. Awarding permits based on cost of compliance

[13] Burtraw, 2001.

would be unnecessarily complicated and rely on uncertain calculations. Additionally, it is difficult to imagine how a cost-of-compliance allocation would work when regulating generators.

Permits could also be allocated based on fuel input rather than electricity output. This method would account for the variations in fuel mix used to generate electricity. Participants that rely on more carbon-intensive energy would receive more allowances (see Appendix B). This method would help even out compliance costs among different participants. However, this is again a method that would penalize entities that have engaged in early action efforts to reduce emissions. From a source-based regulatory perspective, this method does not motivate generators to improve plant efficiency. Therefore, DRA does not support this method.[14]

Q11. Should the method for allocating emission allowances remain consistent from one year to the next, or should it change as the program is implemented?

The allocation methodology should remain constant from year to year.

Q12. If new market entrants receive emission allowance allocations, how would the proper level of allocations be determined for them?

[14] **A note on renewable energy:** An important consideration under this allocation method is the potential allocation of permits to renewable energy projects. On the one hand, California wishes to promote renewable energy. Including renewables in the allocation process would provides one more financial incentive for renewables, thereby rewarding renewable energy for its positive societal externalities. The additional revenue generated by the unneeded permits would be another way to make renewables financially competitive with traditional energy sources. On the other hand, freely allocating permits for electricity from renewable sources would result in windfall profits. This extra incentive for renewables would be in addition to existing subsidies and other financial incentives, including those provided by the Renewable Portfolio Standard Program and the California Solar Initiative. Whether providing all these financial incentives to renewable energy projects is prudent is difficult to address in the absence of more information about the cost and benefits of each incentive. However, this issue should be investigated more completely before the Commission and CEC make a final recommendation to CARB about the treatment of renewables in the allocation process.

One option for allocating allowances to new market entrants is to set aside a reserve of allowances. The amount of reserved allowances would depend on the length of the compliance cycle - the longer the compliance cycle, the more reserved allowances would be necessary to ensure a level playing field for new entrants. The allocation methodology used for incumbents should be applied to new entrants to determine the level of their allowances.

Another option to allocate allowances to new market entrants is to subject all participants, incumbent or new entrant, to an allowance true-up process at the end of each allowance cycle. Emission allowance for departing loads, e.g. community choice aggregators, will then be transferred from the incumbent utility during the true-up.

Q13. If emission allowances are allocated based on load/sales, population, or other factors that change over time, how often should the allowance allocations be updated?

DRA tentatively proposes a tri-annual update of allowance allocations, based on the electricity sales of each LSE, with a true-up process on allocated allowances as discussed in Q12. A true-up process can help to prevent an LSE from over-forecasting its electricity sales in order to obtain more allowances. An LSE may be allotted additional allowances or be required to relinquish allowances based on its actual sales in those three years.

Q14. If emission allowances are allocated based on historical emissions ("grandfathering") or benchmarking, what base year(s) should be used as the basis for those allocations?

DRA does not support a "grandfathering" allocation methodology. However, if emission allowances are allocated based on historical emissions, DRA proposes using 1990 as the base year for the allocations. This will ensure that entities will receive credits for their early actions to reduce GHG emissions. It would be inappropriate to update allowance allocations if the "grandfathering" methodology is selected since the updating process will discount the benefits of early actions. Similarly, a true-up process would not apply if the "grandfathering" methodology is selected. Under a departing load scenario, the incumbent utility should be required to relinquish allowances based on the proportion of sales for the departing load relative to its total sales.

As discussed in the beginning of Section D, a benchmarking method that sets a permitted level of emissions per unit of output is similar to an output-based allocation method. Assuming that allowances were distributed every three years ("allocation period"), the allocations to each entity would be based on the projected output for three years starting with the first year when carbon cap regulation takes effect. Thus, if regulation begins in 2012, allowances will be calculated based on the projected output for 2012 through 2014. Note that the allocation period need not coincide with the compliance period.

Q15. If emission allowances are allocated based initially on historical emissions ("grandfathering"), should the importance of historical emissions in the calculation of allowances be reduced in subsequent years as providers respond to the need to reduce GHGs? If so, how should this be accomplished? By 2020, should all allocations be independent of pre-2012 historical emissions?

DRA does not support an allocation methodology based on historical emissions. Should the Joint Commissions decide to use a grandfathering allocation methodology as a starting point for the electricity and natural gas sector in 2012, DRA recommends allocation in the subsequent years transition to an output-based methodology. The following example illustrates how such a transition can be achieved.

Assume there are three firms in the electricity sector. In 1990 (base year), Firm A, Firm B, and Firm C produced 40%, 25%, and 35% of the total emissions respectively. For simplicity, assume the proportion of projected electricity output for the three firms remain constant between 2012 and 2016 at 50%, 30%, and

20%. Allowances in the first year of carbon cap regulation (2012) will be distributed based on historical emission ratios only, i.e. 40%, 25%, and 35%. For each subsequent year, there will be less weighting on historical emissions with increased weighting on projected output. In this example, the weightings for historic emission versus projected output in the second year (2013) are 80% and 20% respectively; in the third year (2014), the weightings are 60% and 40%. Note that by the sixth year of compliance, allocations are independent of pre-2012 historical emissions.

Assumptions	**Firm A**	**Firm B**	**Firm C**
Relative contribution to emissions based on 1990 base year	40%	25%	35%
Relative electricity output projected for 2012 through 2015	50%	30%	20%
Examples			
Proportion of total emissions allocated in 2012 (first year of compliance)	40%	25%	35%
Proportion of total emissions allocated in 2013 (second year of compliance)	42%	26%	32%
Proportion of total emissions allocated in 2014 (third year of compliance)	44%	27%	29%
Proportion of total emissions allocated in 2015 (forth year of compliance)	46%	28%	26%
Proportion of total emissions allocated in 2016 (fifth year of compliance)	48%	29%	23%
Proportion of total emissions allocated in 2016 (sixth year of compliance)	50%	30%	20%

Q16. Should a two-track system be created, with different emission allowances for deliverers/first sellers or retail providers with legacy coal-fueled power plants or legacy coal contracts? What are the factors and trade-offs in making this decision? How would the two tracks be determined, e.g., using an historical system emissions factor as the cut-off? How should the allocations differ between the tracks, both initially and

> over time? What would be the market impact and cost consequences to consumers if a two-track method were used?

DRA does not support a two-track allocation system. The same difficult issues of how to distribute allowances between the "clean" track versus the "dirty" track and how to eventually "merge" the two tracks would remain under a two-track system, with no clear benefits over a single allocation methodology that applies to all regulated entities within the electricity sector. Assuming that some of the allowances will be sold through an auction, a portion of the auction revenue can be used to provide relief to individuals that suffer financially due to the implementation of a cap-and-trade scheme.

> Q17. If emission allowances are allocated administratively to retail providers, should other adjustments be made to reflect a retail provider's unique circumstances? Comment on the following examples, and add others as appropriate:
>
> a. Climate zone weighting to account for higher energy use by customers in inclement climates, and
>
> b. Increased emission allowances if there is a greater-than-average proportion of economically disadvantaged customers in a retail provider's area.

An output-based allocation methodology already accounts for climate differences across the state, with more allowances given to LSEs serving customers in warmer climate zones who therefore have higher energy use.

DRA does not support categorically increasing emission allowances if there is a greater than average proportion of economically disadvantaged customers in a retail provider's area. Rather, financial assistance can be offered to such economically disadvantaged customers. AB32 mandates the creation of an environmental justice committee with "representatives from communities in the state with the most significant exposure to air pollution, including [ ] communities with minority populations or low-income populations or both."[15] The committee is expected to provide recommendations to address potential issues specific to their constituencies.

> Q18. Should differing levels of regulatory mandates among retail providers (e.g., for renewable portfolio standards, energy efficiency investment, etc.) be taken into account in determining entity-specific emission allowance allocations going forward? For example, should emission allowance allocations be adjusted for retail providers with high historical investments in energy efficiency or renewables due to regulatory mandates? If those differential mandates persist in the future, should they continue to affect emission allowance allocations?

Under a load-based approach, retail providers should be credited for their efforts in pursuing energy efficiency savings by including the projected or verified EE savings in their projected or actual sales output when determining their allowance allocation. For a given level of electricity sales, the higher the EE savings, the more allowances would be assigned to the LSE. As with the electricity sales, the EE savings should be trued-up at the end of each allocation period to discourage over-forecasting. The determination of the actual EE savings at the investor-owned utilities is governed by a set of evaluation, measurement, and verification protocols adopted by the CPUC.

There is no need to differentiate renewable power from non-renewable supply when allocating allowances based on sales output. The higher the level of renewable power in its overall supply mix, the more excess carbon permits the LSE will have for selling into the California cap and trade market.

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[15] Health and Safety Code section 38591 (a).

Q19. How often should the allowance allocation process occur? How far in advance of the compliance period?

DRA recommends that allowance allocation take place every three years; the true-up of allowances for the first allocation period can take place at the same as the initial allocation for the second allocation period. Assuming that the compliance period is also every three years, allowances can be allocated at the start or no more than 6 months prior to the start of the compliance period.

Q20. What are the distributional consequences of your recommended emission allowance allocation approach? For example, how would your method affect customers of retail providers with widely differing average emission rates? Or differing rates of population growth?

Under a load-based point of regulation, the output-based allocation method would likely lead to increased retail electricity costs for LSEs with high carbon-content fuel mix. Given two LSEs with the same amount electricity sales, the LSE with the "dirtier" fuel mix will need more emission permits, which in turn will increase its cost of service. However, because coal-fired generation is cheaper than natural gas-fired generation, the LSE with the "dirtier" fuel mix may still have retail electricity rates lower than the LSE with the "cleaner" fuel mix after accounting for the emission permit price.[16] Based on a recent CEC study,[17] economic dispatch will be determined by the sum of the variable operating costs of the plant as well as the price of a carbon adder (which is equivalent to the cost of carbon allowance.) A $10/ton carbon adder will have little impact on the dispatch, but at $40/ton, many of the coal plants become more expensive than

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[16] For California LSEs, low retail electricity rates are generally associated with high GHG emissions to serve customer load. San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) illustrated the inverse correlation between electricity rates and GHG emission at pages 6-7 of their August 15, 2007 reply comments in response to the Administrative Law Judge Ruling requesting comments on the Market Advisory Report at pages 6-7.

[17] CEC Scenario Analysis of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report, Third Addendum, September 2007, p.27-34.

natural gas plants.[18] The precise rate impacts on an individual LSE will depend on its fuel mix, the price of the allowance as well as the quantity of free allowances allocated in a given period. Furthermore, DRA favors the output-based allocation with periodic true-up and updating, which discourages LSEs from over-projecting their sales forecast, adjusts for demand changes based on population growth, and accommodates scenarios such as departing growth and the entry of new retail providers.

E. Emission Allowances With a First Seller Point of Regulation

Q21. Would a deliverer/first seller point of regulation necessitate auctioning of emission allowances to the deliverers/first sellers?

Yes, as discussed in the responses to Q2, a first-seller point of regulation would necessitate a 100% auctioning of emission of allowances.

Q22. Are there interstate commerce concerns if auction proceeds are obtained from all deliverers/first sellers and spent solely for the benefit of California ratepayers? If there are legal considerations, include a detailed analysis and appropriate legal citations.

The Commerce Clause of the United States Constitution[19] allows Congress to regulate interstate commerce. The Commerce Clause's "dormant" aspect limits the States' ability to discriminate against interstate commerce. The dormant Commerce Clause prohibits economic protectionism, or regulatory measures designed to benefit in-state economic interests by burdening out-of-state competitors.[20]

[18] According to the CEC scenario study, historical operating costs were about $20/MWh for a coal plant with an 11,000 Btu/kWh heat rate and about $60/MWh for a natural gas combined cycle plant with about a 7,000 Btu/kWh heat rate.

[19] United States Constitution, Article I, Section 8, clause 3.

[20] New Energy Co. v. Limbach, 486 U.S. 269 (1988).

The Supreme Court in West Lynn Creamery, Inc. v. Healey,[21] 512 U.S. 186 (1994) considered whether a Massachusetts tax on all milk sold within the state, coupled with a subsidy to Massachusetts diary farmers, violated the Commerce Clause. The Court concluded that the Massachusetts' regulatory mechanism was impermissible because it was in effect a tariff on out-of-state milk. The Court in West Lynn Creamery acknowledged that if taxes do not discriminate between in-state and out-of-state products, they are generally allowed under the Commerce Clause.[22] However, the Massachusetts tax on milk sales whose proceeds were used for the benefit of Massachusetts dairy farmers was found to be akin to enacting a tariff on out-of-state milk.[23] The Court found that this was a form of economic protectionism and was thus impermissible.

The rationale of West Lynn Creamery demonstrates the importance of allocating proceeds from an auction of GHG allowances to both in-state and out-of- state participants in a matter that minimizes potential claims of "protecting" in-state economic actors. Using auction proceeds to help businesses impacted by the GHG compliance scheme appears vulnerable to a claim of protecting in-state economic interests. Using the money to finance reduction in state taxes, or for rebates to tax payers may be less likely to evoke successful claims of economic protectionism, but would be unrelated to the primary goal of reducing GHG emissions. Using auction proceeds to improve public transportation appears related to the primary goal of reducing GHG emissions and may be less likely to be viewed as protection of in-state economic interests.

Q23. If you believe 100% auctioning to deliverers/first sellers is not required, explain how emission allowances would be allocated to deliverers/first sellers. In doing so, answer the following:

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[21] 512 U.S. 186 (1994).

[22] Id., at 200.

[23] Id. at 195.

a. How would the amount of emission allowances given to deliverers/first sellers be determined during any particular compliance period?

b. How would importers that are marketers be treated, e.g., would they receive emission allowance allocations or be required to purchase all their needed emission allowances through auctions? If allocated, using what method?

c. How would electric service providers be treated?

d. How would new deliverers/first sellers obtain emission allowances?

e. Would zero-carbon generators receive emission allowance allocations?

f. What would be the impact on market performance, prices, and costs to customers of allocating emission allowances to deliverers/first sellers?

g. What would be the likelihood of windfall profits if some or all emission allowances are allocated to deliverers/first sellers?

h. How could such a system prevent windfall profits?

As discussed in the responses to Question 2, DRA believes that if the point of regulation is the first-seller or importer, 100% of emission of allowances should be auctioned.

Q24. With a deliverer/first seller point of regulation, should administrative allocations of emission allowances be made to retail providers for subsequent auctioning to deliverers/first sellers? If so, using what allocation method? Refer to your answers in Section 3.4.1., as appropriate.

No, emission allowances should not be allocated to retail providers for subsequent auctioning to first sellers. Under a first seller regulatory structure, retail providers could be an importer of electricity and would therefore be subjected to the same emission auction rules as other first sellers including in-state generators and power marketers. Allocating allowances to retail providers to be auctioned to market participants would create a conflict of interest.

Q25. If you recommend allocation of emission allowances to retail providers followed by an auction to deliverers/first sellers, how would such an auction be administered? What kinds of issues would such a system raise? What would be the impact on market performance, prices, and costs to customers?

Not applicable.

F. Natural Gas Sector

Q26. Answer each of the questions in Section 3.4.1. except Q16, but for the natural gas sector and with reference to natural gas distribution companies (investor- or publicly-owned), interstate pipeline companies, or natural gas storage companies as appropriate. Explain if your answer differs among these types of natural gas entities. Explain any differences between your answers for the electricity sector and the natural gas sector.

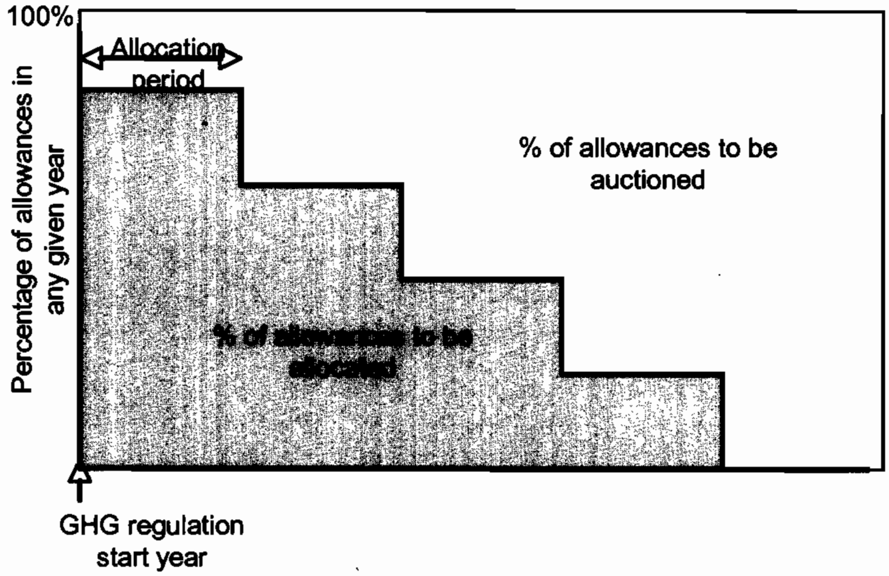
Q27. Are there any other factors unique to the natural gas sector that have not been captured in the questions above? If so, describe the issues and your recommendations.

The recommendations DRA provides in Section 3.4.1 for the electricity sector are also applicable to all entities that comprise the natural gas sector. Specifically, an output-based allowance allocation methodology that is subject to a true-up based on actual sales is also appropriate for investor- and publicly-owned natural gas distribution companies and interstate pipeline companies. Moreover, the advantages associated with an output-based approach, as enumerated above, are shared by both the electricity and natural gas industries. Any subtle differences in ratemaking and rate design between the electricity and gas industry participants to account for emissions allowances can be settled in each industry participant's respective general rate cases (GRC). Nevertheless, utilizing the same overarching output-based emissions allocation methodology for the two industries is feasible. It is also practical to have a single, consistent methodology between the industries from a regulatory enforcement standpoint. Therefore, DRA sees no need to provide any additional analysis or alternative recommendations for an allocation methodology for the natural gas industry.

G. Overall Recommendation

Q28. Considering your responses above, summarize your primary recommendation for how the State should design a system whereby electricity and natural gas entities obtain emission allowances if a cap and trade system is adopted.

DRA recommends a gradual transition from primarily free allowance allocation (i.e. up to 90% of the total allowances) in the initial years of GHG regulation to 100% auction of allowances (see figure below). This approach applies under both the load-based and the source-based regulatory perspectives. Allowances should be allocated based on projected output/electricity sales for three years beginning with the first year of GHG regulation (i.e. 2012), with a true-up process at the end of the three-year period to adjust the allocated allowances based on actual sales. Up to 5% of the allowances can be reserved for allocation to new entrants. However, these new entrants would also be subjected to the true-up process. Under a load-based regulatory scheme, the projected electricity sales should include energy efficiency savings. Allocation of allowances should be updated every three years to reflect changing demographics and competitive landscape.



Under a first-seller regulatory approach, DRA recommends auctioning 100% of allowances from the start of the GHG regulatory period. The allowance auction should be administered by a neutral party who would not be participating in the auction.

II. III. CONCLUSION

DRA appreciates the opportunity to provide these comments in advance of the Allowance Allocation workshop, and respectfully requests that the Joint Commissions consider these comments in formulating their recommendation to the California Air Resources Board.

Respectfully submitted,

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October 31, 2007

APPENDIX I

Assumptions:

- A total of 3 participants in the State.
- Overall cap for electricity is 8 million pounds of CO_2

Note: These numbers are for illustrative purposes only and do not represent actual data.

A. Benchmarking under a cap

Total State Electricity Sales (Output): 10,000 MWh
Cap: 8,000,000 pounds CO_2

Benchmark = average emission rate permitted = 8,000,000 pounds CO_2 / 10,000 MWh
= 800 pounds CO_2 per MWh

Participant	**Output (MWh)**		**Benchmark (lbs CO_2/MWh)**		**Allowances Granted (lbs CO_2)**
A	5,000	x	800	=	4,000,000
B	3,000	x	800	=	2,400,000
C	2,000	x	800	=	1,600,000
Total	*10,000*	*x*	*800*	=	*8,000,000*

B. Allocation based on electricity sales

Total State Electricity Sales (Output): 10,000 MWh
Cap: 8,000,000 pounds CO_2

Participant	**Output (MWh)**		**Total State Output (MWh)**		**Ratio of Allowances Granted**		**Allowance Cap (lbs CO_2)**		**Allowances Granted (lbs CO_2)**
A	5,000	/	10,000	=	50%	x	8,000,000	=	4,000,000
B	3,000	/	10,000	=	30%	x	8,000,000	=	2,400,000
C	2,000	/	10,000	=	20%	x	8,000,000	=	1,600,000
Total	*10,000*	/	*10,000*	=	*100%*	*x*	*8,000,000*	=	*8,000,000*

Allowances granted to each participant are the same using either the benchmarking approach or the electricity sales basis.

APPENDIX II

C. Allocation based on fuel input

Assumptions:

- A total of 3 participants in the State.
- Overall cap for electricity is 8 million pounds of CO_2
- Emission factors:
    - Coal – 1800 pounds CO_2 per MWh
    - Natural Gas – 1000 CO_2 per MWh
    - Renewables – 0 CO_2 per MWh

Note: These numbers are for illustrative purposes only and do not represent actual data.

Participant A

- Total output: 5,000 MWh
- Fuel mix: 50% natural gas, 50% renewables

Participant B

- Total output: 3,000 MWh
- Fuel mix: 50% coal, 50% natural gas

Participant C

- Total output: 2,000 MWh
- Fuel mix: 100% coal

Participant	Output by fuel type (MWh)	Fuel Type	Emission Factor (lbs CO_2/MWh)	Total Est. Emissions (lbs CO_2)	Ratio of Allowances Granted (subtotal/total)	Allowances Granted (Cap x Ratio)
A	2,500	Natural Gas	1,000	2,500,000		
	2,500	Renewables	0	0		
Subtotal	*5,000*			*2,500,000*	24%	1,920,000
B	1,500	Natural Gas	1,000	1,500,000		
	1,500	Coal	1,800	2,700,000		
Subtotal	*3,000*			*4,200,000*	41%	3,280,000
C	2,000	Coal	1,800	3,600,000	35%	2,800,000
Subtotal	*2,000*			*3,600,000*		
TOTAL	*10,000*			*10,300,000*	*100%*	*8,000,000*

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of **"COMMENTS OF THE DIVISION OF RATEPAYER ADVOCATES ON ALLOWANCE ALLOCATION ISSUES"** in **R.06-04-009** by using the following service:

[X] E-Mail Service: sending the entire document as an attachment to all known parties of record who provided electronic mail addresses.

[ ] U.S. Mail Service: mailing by first-class mail with postage prepaid to all known parties of record who did not provide electronic mail addresses.

Executed on October 31, 2007 at San Francisco, California.

/s/ HALINA MARCINKOWSKI
Halina Marcinkowski

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