BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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| 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 (Filed April 13, 2006) |

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**CORRECTED COMMENTS OF THE DIVISION OF RATEPAYER ADVOCATES ON ELECTRICITY SECTOR RESPONSIBILITY, ALLOWANCE ALLOCATION, FLEXIBLE COMPLIANCE MECHANISMS, AND MODELING**

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# I. INTRODUCTION

Pursuant to the May 20, 2008 "Administrative Law Judges' Ruling Modifying Schedule and Correcting Suggested Outline for Comments and Reply Comments," the Division of Ratepayer Advocates (DRA) submits the following comments on design features of a potential cap-and-trade methodology for achieving the greenhouse gas (GHG) reductions required by the California Global Warming Solutions Act of 2006 (Assembly Bill (AB) 32). DRA's comments explain how to allocate allowances, incorporate flexible compliance options, use the results of modeling, and apportion responsibility for reducing GHG emissions to electricity sector customers in order to achieve the reductions required by AB 32 while minimizing the risks and costs to electric ratepayers. For example, the California Air Resources Board (ARB) should not increase electricity sector mandates at this time because doing so could increase overall compliance costs for ratepayers without increasing GHG reductions (discussed further in Section VII). At the same time, the sheer complexity of designing a cap-and-trade regime that will accomplish the GHG reductions required by AB 32, and the potential for adverse unintended consequences to electric ratepayers and California as a whole, beg the question whether a cap-and-trade regime is the best way to accomplish those reductions.

Parties have done a considerable amount of research and analysis on the use of a cap-and-trade regime to reduce GHG emissions, but many questions still remain about its efficacy for GHG emissions mitigation at the lowest cost to ratepayers. For instance, the costs and benefits of the use of a carbon fee as a potentially less complex and easier to administer mechanism for reducing GHG emissions has not been explored in this proceeding. DRA recognizes that a carbon fee could require a lengthy period of adjustments and trial-and-error in order to achieve the desired quantity of reductions in fulfillment of AB 32, but it has the potential to achieve results with less possibility for market manipulation and unintended consequences. There is clearly no foolproof, failsafe, or perfectly equitable way to meet the mandates of AB 32, but DRA recommends the exploration of the use of a carbon fee to reduce GHG emissions before a final determination is made.

Nevertheless, DRA issues several proposals and recommendations for designing a cap-and-trade system that seek to shield ratepayers from the inherent risk in this market-based policy tool, to the extent that it is possible to do so. The Joint Commissions should keep the following principles in mind as policy guidelines when evaluating remaining Phase II issues and proposals:

- **Ratepayer Protection**: A cap-and-trade market should only be adopted as a tool for GHG emissions reductions in California so long as it is designed with adequate protection mechanisms and can fulfill AB 32 at the lowest cost to ratepayers.

- **Equity**: If adopted, a cap-and-trade system should balance the costs of total emissions reductions across all sectors in California.

- **Cost Minimization and Flexibility**: Regulatory mandates must not be excessive if a cap-and-trade program is also pursued, as overly strict mandates will negate the purpose of having a cap-and-trade program (i.e., flexibility and pursuance of least-cost options).

- **Integrity**: The cap-and-trade system, core regulatory measures, and flexible compliance mechanisms should be designed to ensure that emissions reductions are being confirmed and validated. Monitoring, verification, and enforcement procedures should be stringent enough to ensure that the ratepayer investment in the California GHG mitigation system is fair, cost-effective, and meeting AB 32 objectives.

The detailed proposals and recommendations on behalf of ratepayers that follow are consistent with these principles.

## II. GENERAL ISSUES

### A. Overlap and Compatibility Issues Among Non-Market Based Programs

#### 1. The RPS Proceeding: Renewable Energy Credits and GHG Attributes, and the Impact on Carbon Allowance Allocation

Concurrent with this greenhouse gas proceeding (R.06-04-009), the CPUC has an open proceeding on the renewable energy portfolio and tradable renewable energy credits (RECs) (R.06-02-012). An important, and unresolved, question is whether renewable generators will be able to receive credit for both the renewable energy (in the form of a REC) and for the avoided GHGs emissions (in the form of a carbon allowance). This issue is being addressed under R.06-02-012, and is expected to be resolved in a CPUC decision this summer. DRA believes that the decision on whether RECs will include the GHG attribute could have significant implications for GHG allowance allocation, and therefore the decisions must be coordinated.

If, under R.06-02-012, the CPUC decides that RECs will *include* the GHG attributes (that is, the value of the avoided emissions), then renewable energy will be assigned default carbon emissions to effectively 'strip' the null power of all of its green attributes.[1] If, simultaneously, the CPUC decides to allocate some allowances based on output or historical emissions,[2] then renewable generators should also be given allowances to ensure they are not disadvantaged. On the other hand, if RECs do *not* include the GHG attribute, then renewable energy will not be assigned default carbon emissions. In this case, they should not receive free allowances, as this would simply provide them with a windfall profit because generators would be able to sell both RECs and GHG allowances for the same power.

The decisions regarding the definition of a REC and whether to give allowances to renewable generators are clearly interdependent. DRA urges the CPUC to make sure these two decisions are coordinated. Without coordination, there is a risk that renewables would be either harmed or excessively advantaged.

### 2. Regulatory Mandates and Cap-and-Trade: Striking an Effective Balance to Minimize Costs to Ratepayers

In Decision (D.) 08-03-018,[3] the Commission recommended supporting a 33 percent RPS mandate. DRA argued that it was still premature to mandate an increase in

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[1] This action has been suggested in order to prevent renewable generators from being able to sell both a REC and a carbon allowance for the same energy.

[2] Because of the default emissions assigned, renewables might also be considered to have historical emissions.

[3] D.08-03-018.

renewable energy procurement beyond the current Renewable Procurement Standard statutory requirements.[4] DRA remains concerned that this recommendation was made without full consideration of the relative cost-effectiveness of the RPS program compared to other GHG-reducing strategies in California as a whole. Renewables in California are expensive, utilities are already struggling to meet the current 20 percent mandate, and there is a shortage of transmission available to access renewable energy. A mandated increase in the renewable procurement will further exacerbate the cost impacts on ratepayers. As illustrated by the E3 results, a 33% RPS mandate translates to a GHG reduction cost of $133/tonne.[5] Without first evaluating the cost effectiveness of other GHG reduction strategies in other sectors, the Commission should refrain from increasing the renewables mandate and imposing an unnecessarily costly burden on electricity ratepayers.

The purpose of a cap-and-trade system is to allow the market to find the lowest-cost reductions. By increasing regulatory mandates, the cap-and-trade program will be responsible for a smaller portion of the reductions, and therefore the overall economic gains from instituting a cap-and-trade program will be limited. Given the design complexity of a cap-and-trade program and the costs of administering and monitoring such a program to prevent market manipulation and to ensure compliance, ARB should not rely too heavily on direct regulations to complement a cap-and-trade program in order to meet the goals of AB 32. If 33 percent renewable energy is in fact a cost-effective way of meeting AB 32 goals, then the market will provide that incentive.

DRA understands that aggressive regulatory mandates might be pursued to achieve social goals other than GHG reductions; however, if the cap-and-trade component represents a very small portion of reductions, then ARB should investigate whether the administrative costs and burden are worth having a cap-and-trade at all.

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[4] Comments of the Division of Ratepayer Advocates on the Interim Opinion on Greenhouse Gas Regulatory Strategies, February 28, 2008, p. 5 – 8.

[5] E3 Electricity & Natural Gas GHG Modeling Revised Results and Sensitivities, May 13, 2008, p.16.

## III. ALLOWANCE ALLOCATION

DRA recommends a phased-approach to a 100% auction. The fact that markets are imperfect is often overlooked in economic theories; this has been the Achilles heel to the California electricity market restructuring experience. It is important to minimize exposure of California ratepayers to the potential problems of an untested 100% auction market.

### A. Overview of Proposal

DRA recommends a phased approach, with initially 25% of the allowances to be auctioned by an independent auction administrator and 75% of allowances distributed to deliverers based on their historical emissions.[6] The proportion of allowances that would be freely allocated after the first year would decrease by 15% every year, such that by 2017, 100% of the total available allowances to the electricity sector would be auctioned. The relative proportions of the allowances to be freely allocated and auctioned are summarized in Table 1.

[6] The proposal set forth by DRA here is a departure from an earlier DRA position in its response to the October 15, 2007 ALJ Ruling request Comments on Allowance Allocation Issues. While DRA recommended a 100% auctioning of emission allowances under a first-seller point of regulation, DRA has since reviewed other cap-and-trade programs of environmental attributes and has found no example to date of a program starting with a 100% auction.

Table 1By starting with a small but significant portion (25%) of the allowances for auctioning, California ratepayers will be protected from potential problems stemming from a sudden regulatory shift, but there will still be adequate market liquidity for the auctioned allowances. At the same time, since windfall profit is a likely byproduct of any allocation methodology that gives free allowances to non-regulated entities, it is important to make a relatively quick transition to a full auction such that any windfall profits would be short-term and declining in nature.

**Table 1: Suggested Allocation of Allowances**

| Year | Portion Allocated | Portion Auctioned |
|---|---|---|
| 2012 | 75% | 25% |
| 2013 | 60% | 40% |
| 2014 | 45% | 55% |
| 2015 | 30% | 70% |
| 2016 | 15% | 85% |
| 2017 | 0% | 100% |

To establish a baseline of historic emissions, DRA proposes that ARB use the average emissions during the 2004-2006 timeframe. Given that the California Legislature adopted AB 32 in 2006, setting the baseline to emissions around that year would reward early actions taken after the passage of AB 32. DRA proposes using a three-year average to account for varying weather conditions from year to year and the fact that a generator may have significant maintenance outages planned in any one year.

DRA further recommends that auction revenue within the electricity sector should primarily be returned to ratepayers to lower the cost impact of carbon regulations. A portion of the auction revenue can be used to pay for auction administration and to fund the Market Oversight board (discussed later in this section); however the percentage of the auction revenue used to support such administrative functions should be capped.

### B. Rationale Behind DRA's Proposal

#### 1. A transition to a full auction is necessary to ensure a smooth transition to a lower-carbon economy.

DRA supports a 100% auction of allowances as the ultimate goal of the allowance allocation methodology. Auctioning of emission allowances meets three of the four evaluation criteria identified by Joint Staff, namely, minimizing wealth transfer from consumers to producers, administrative simplicity, and accommodation of new resource entrants. The fourth criteria, minimizing wealth transfer between customers of retail providers, under a 100% auction program can be addressed by initially shifting a larger share of the auction revenue to retail providers that might be disadvantaged due to their existing ownership in emissions-intensive resources. Over time, there should be no differential in auction revenue distribution across all retail providers as they adjust their resource portfolios to reduce emissions.

Nevertheless, DRA cautions against starting a cap-and-trade program with a full auction of allowances. It is unclear how the market would react to such a sudden transition. The Market Advisory Committee acknowledged in its final report that there is a lack of familiarity with auctions in a regulatory context.[7] There is no experience to date within the U.S. or abroad with a 100 percent auction of allowances in emission trading programs. The last abrupt change to the California electricity utility industry, introduced by the restructuring legislation AB 1890 passed in 1996, collapsed within three years after the program began in 1998. Evidence of market power was noted as early as 1999, and by mid-2000, significant energy price increases were recorded[8], with San Diego Gas & Electric Company filing a complaint in August 2000 alleging market manipulations. Litigation related to the energy crisis is ongoing at the Federal Energy Regulatory Commission, in California state courts, and at the United States Supreme Court and may continue for years. Based on the lesson from the California restructuring experience, the Joint Commission should recommend a cap-and-trade program design that allows time to refine rules related to the auction program. The additional administrative burden and the likely windfall profits resulting from free allowances given to independent power producers are justified in the short term in order to decrease the exposure of California ratepayers to potential market dysfunction.

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[7] Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California, Market Advisory Committee, June 30, 2007, p.58.

[8] Background on Electricity Policy, California Senate Energy, Utilities and Communications Committee March 7, 2007 Hearing (http://www.senate.ca.gov/ftp/SEN/COMMITTEE/STANDING/ENERGY/_home/03-13-07backgroundattach.htm)

A transition period also allows the covered entities[9] to make necessary adjustments to their financial plans to account for the impacts of GHG compliance obligations on their operating cash flow. Under a 100% auction scheme, a deliverer would have to purchase all of the allowances to cover its emissions. In the absence of certainty on allowance prices under an auction market, it would be very difficult for covered entities to plan their cash flow requirements. Some of the covered entities, especially the publicly owned utilities who have deliverer responsibility for a significant portion of their resource portfolio, may have difficulty in making the abrupt change in their cash-flow requirements if the ARB decides on a 100% auction program beginning in 2012. A transition to a 100% auction would provide an adjustment period for the covered entities to ramp up to the financial demands of carbon regulation.

An important outcome of an allowance auction is the creation of a revenue source based on auction proceeds. The question of which entity will hold the purse strings to the auction proceeds remains open. In particular, auction proceeds as a new revenue source under the control of a state agency may be vulnerable to raiding when there are shortfalls in the state budget[10]. Given the current uncertainty of how auction proceeds will be distributed, it is in the best interest of ratepayers to slowly build up this revenue and develop the mechanisms to insure that auction proceeds are used in a way that best meets the criteria established in AB 32.

### 2. The extent of windfall for the electricity sector under free allowance allocation to deliverers is limited by the pre-existing procurement contracts.

DRA recognizes that any methodology that gives away allowances to non-regulated entities is likely to result in windfall profit. An independent generator would

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[9] In this discussion, DRA differentiates a covered entity from a regulated entity within the electricity sector. Covered entities include all first deliverers that would be required to surrender allowances to meet compliance obligations under a cap-and-trade program, while regulated entities are those that are subjected to electricity retail price regulations.

[10] As an example, $29 million of $52 million targeted for energy efficiency in Wisconsin in 2004-05 was diverted to general tax funds. (Source: "When States Raid Public Utility Funds", Gary Stern, EnergyBiz Magazine, July/August 2005.)

reap windfall profits when it includes the opportunity costs of GHG allowances in the wholesale electricity price despite the fact that the allowances are allocated at no cost to the generator.[11] In fact, the EU ETS market provides empirical evidence of such market behavior, with the power producers that received free allocations during Phase I of the ETS having realized substantial gains.[12] However, the extent of the overall windfall for the electricity sector is limited by three factors: (i) pre-existing procurement contracts, including utility-owned generation resources, (ii) a relatively quick transition to full auction, and (iii) deliverer responsibility for new power contracts.

Utility-owned generation is by definition immune to the issue of generator windfall due to regulatory oversight. Similarly, pre-existing procurement contracts are not susceptible to generator windfall since the generator will not be able to adjust the contract price to reflect market wholesale prices. At the May 6, 2008 workshop, E3 asserted that approximately 40% of statewide generation resources assumed for 2020 are specified resources, which includes utility-owned generation and long-term procurement contracts.[13] The share of specified resources varies from utility to utility. In the case of the Los Angeles Department of Water and Power (LADWP), specified resources account for about 80% and 65% of its total resource need in 2008 and 2020 respectively, whereas for Southern California Edison, specified resources account for around 62% and 38% of their resource need in 2008 and 2020 respectively.

DRA recommends a transition from a predominantly free allowance allocation methodology to a full auction within 5 years. Given this relatively quick transition to a full auction, any windfall profits that might result from the freely distributed allowances would be short term and declining in nature. Instead of relying on these free allowances,

[11] In contrast, a regulated entity such as an investor-owned utility would not be allowed to pass on the opportunity costs to its retail customers.

[12] "Allocating Allowances in a Greenhouse Gas Trading System", March 1, 2007, National Commission on Energy Policy staff paper, p. 14 "The European Experience with Allocation."

[13] E3 GHG Modeling Revised Results and Sensitivities, May 13, 2008. Slide # 36 "Generation Assignment Shares in 2008 and 2020, Reference Case by LSE"

regulated entities should anticipate the investments necessary to reduce their GHG emissions in the long term.

Under the DRA proposal, free allowances will be given to deliverers as defined in D.08-03-018. In the years leading up to 2012, it is conceivable that some of the new procurement contracts will explicitly put the "deliverer" responsibility on the procuring utility, thus shifting the carbon risk from the generator to the utility. Given the current regulatory structure of the IOUs in California, it is unlikely that the IOUs would be able to pass on the opportunity cost of the allocated allowances to their retail customers. Likewise, vertically-integrated publicly owned utilities would likely face pressure to flow the benefits of allowances to their ratepayers.

### 3. A historic emissions-based allowance methodology is superior to an output-based allowance methodology in meeting the Joint Staff evaluation criteria.

As discussed earlier, any methodology that gives away allowances to non-regulated entities is likely to result in windfall profits. Therefore, when comparing an output-based allowance methodology with a historic emissions-based allowance methodology, DRA focused on three of the Joint Staff evaluation criteria, namely, equity among customers of retail providers, administrative simplicity, and accommodation of new resource entrants. DRA adds two additional criteria – (1) rewards for early action and (2) planning predictability from a deliverer's perspective. The application of each of these criteria is discussed below.

#### a) Equity among customers of retail providers

When GHG regulatory compliance begins in year 2012, different retail providers will have different levels of carbon intensity.[14] In other words, the electricity served by one retail provider has a higher carbon content than that of another retail provider. Assuming that GHG compliance costs of deliverers are fully passed on to retail providers, an output-based allowance allocation methodology will result in equal subsidy for each

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[14] Based on the E3 GHG Modeling results, GHG intensity for the various retail providers in 2012 ranges between around 0.25 tonnes/MWh for PG&E to 0.55 tonnes/MWh for LADWP.

kWh of output. The customers of retail providers with a more carbon-intensive supply portfolio will therefore be paying more on a kWh basis for carbon compliance than customers of retail providers with a less carbon-intensive portfolio. This contradicts the intent of the Commission to avoid "[treating] any market participants unfairly based on their past investments or decisions made prior to the passage of AB 32."[15]

To maintain equity among customers of retail providers, DRA recommends using historic emissions as the basis for allowance allocation. Specifically, DRA proposes that the portion of free allowances allocated to each deliverer be based on the deliverer's average emissions responsibility in the 2004-2006 time period. The relative proportion of allowances distributed to the deliverers will remain constant until 2017, when all allowances will be auctioned.

Under a vertically-integrated electricity market structure, allowances would only be distributed to utility-owned generation. Given the current hybrid market structure in California, some of the allowances will be distributed to retail providers with utility-owned generation, while the rest will go to independent power generators. Assuming that the independent power generators pass on the opportunity costs of the allowances to the retail providers, customers of retail providers that purchase power from independent generators will be paying for their windfall profits. Within California, the investor-owned utilities divested a significant portion of their generation assets during the restructuring era, while many municipal utilities still own most of their generation assets. An historic emissions-based allowance allocation methodology gives customers of vertically integrated utilities an advantage over customers of utilities who purchase most of their power from independent producers. However, this advantage will be eliminated by 2017 when all allowances will be auctioned.

#### b) Administrative Simplicity

From the perspective of encouraging covered entities to deploy efficient technologies to reduce emissions, a historic emissions-based allocation methodology

[15] D.08-03-018, p.8.

should be as equally effective as an output-based allocation methodology. An output-based allocation methodology, however, is far less straightforward in terms of how to calculate the emissions allowances to be allocated to each covered entity. Because the output of each entity will change over time, the proportion of allowances given to each eligible entity will need to be continually recalculated. In addition, it would be unclear whether the allocated allowances should be adjusted ex-post to reflect the actual output, and whether allowances should be given to the deliverers of null power if a tradable renewable energy certificate market becomes a reality. These issues add to the complexity of an output-based allowance allocation approach. The Joint Staff Paper presents a modified output-based allocation methodology that applies a weighting factor to resources based on the fuel type. This modified approach further complicates the issues by the need to determine the appropriate weighting factor for different fuel types and potentially different vintages of generation technologies.

In contrast, a historic emissions-based allocation methodology uses a common basis to determine the total allowances to be allocated to each covered entity with no updating needs. As the pool of free allowances become smaller each year, the covered entities receive the same proportionate amount of free allowances but in smaller quantity. Nevertheless, there are a few design issues related to a historic emissions-based methodology, including the need to ensure a level playing field for new entrants and the treatment of unspecified imports. DRA addresses these issues starting on page 14.

### c) Accommodation of New Resource Entrants

It is not necessary to allocate allowances to new entrants as a means to ensure a level playing field for incumbent deliverers and new entrants alike. New entrants have the opportunity to make decisions to invest in less GHG-intensive technologies while incumbents do not. Given the relatively short transition to 100% auction, new entrants should purchase all of their allowances in the auction.

### d) Rewards for Early Action

The statute requires that the ARB encourages early action by giving appropriate credit for early voluntary reductions prior to the adoption of mandatory emission reduction measures in January 11, 2011. Some parties have argued that a historic emissions-based allocation methodology gives polluters the right to continue emitting while penalizing those that took early actions to reduce emissions. This is incorrect. As long as a prior year is selected as the base year for historic emissions, such that an emitter cannot increase its emissions in order to gain a larger share of allowances, there is no difference between a historic emissions-based and an output-based methodology in terms of economic incentives to reduce emissions between the time when AB 32 was enacted and the start of a cap-and-trade program.[16] In fact, an output-based allocation methodology might give a generator the perverse incentive to increase its output in order to increase its share of allowances.[17]

### e) Planning Predictability From a Deliverer's Perspective

This is an important criterion, especially given that many of the covered entities have not been previously subjected to environmental regulations. It is equally important for the rules of the game to be clear and transparent and for the covered entities to be able to follow these rules without abrupt changes to their business operations. As discussed above, an allocation methodology based on historic emissions provides a predictable and decreasing amount of free allowances to covered entities. In contrast, the number of allowances allocated to each entity under an output-based methodology could vary significantly from year to year depending on its generation output, which in turn could depend on weather and hydro conditions. From a business planning perspective, this variability of allocated allowances is less desirable than a predictable stream of allocated allowances

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[16] DRA interprets that voluntary emissions reductions prior to the enactment of AB 32 do not count as early action.

[17] "Allowance Allocation", Raymond J. Kopp, May 2007, p.5.

### C. Specific Design Issues Related to a Historic Emissions-Based Allocation Methodology

There are several outstanding issues that need to be addressed in order to implement a historic emissions-based allocation methodology. These include: selecting a base year for establishing historic emissions, allowance set-aside for new entrants, treatment of unspecified imports, and provisions for deliverers that cease operations after receiving allowances. DRA addresses these issues as follows.

#### 1. Selecting a base year for establishing historic emissions

Some parties have argued using a base year that dates back as far as 1990 to allow for early action credits be given to entities who have since deployed lower emissions technologies. However, this would contradict the Joint Commissions' intention as stated in D.08-03-018 to avoid "[treating] any market participants unfairly based on their past investments or decisions made prior to the passage of AB 32."[18] At the same time, choosing a base year after 2006 will contradict the Legislation's intent to encourage early action to reduce greenhouse gas emissions.[19] DRA recognizes that varying hydro conditions affect the amount of fossil-fueled based electricity dispatched to meet demand; moreover, a generator may have significant maintenance outages planned in any one year. Therefore, to ensure a fair basis for allocating allowances, DRA recommends that historic emissions for deliverers be calculated based on the average emissions between 2004 and 2006.

#### 2. Allowance set-aside for new entrants

As discussed earlier on page 15, "Allowance set-aside for new entrants," DRA recommends against giving free allowances to new entrants. New entrants should instead purchase allowances from the auction. Therefore, no allowance set-aside is needed for new entrants, other than ensuring that the overall pool is large enough to accommodate new entrants.

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[18] D.08-03-018, p.8.

[19] Health & Safety Code Section 38562 (b) (1).

### 3. Treatment of unspecified imports in the base year

Under a historic emissions-based allocation methodology, free allowances allocated to deliverers will be determined based on their 2006 emissions. For unspecified power imports however, the associated emissions are unknown. For simplicity, DRA recommends using the default 2006 emission rate of 1,100 lbs/MWh for all unspecified power. The free allowances associated with the delivery of unspecified power would then be determined based on the average energy delivered between 2004 and 2006, and the default emission rate.

### 4. Provisions for deliverers that cease operations after receiving allowances

Under any allocation methodology that distributes allowances to deliverers, it is necessary to develop rules to make sure that the system is not exploited. For example, a deliverer may decide to cease operation after receiving allowances, then set up a new entity to claim additional allowances (or "double-dip") for the delivery of the same energy. DRA proposes a simple rule to prevent any potential double-dipping: allowances associated with a specific generation unit should only be allocated once for any given year.

DRA further proposes that allowances allocated to any generating unit that is planned for retirement that year be prorated based on the months of operations. For unplanned closure of generating unit or business entities, the allocated allowances (prorated based on months of non-operation in that year) should be deemed void for compliance purposes. In other words, these allowances would have zero value in the trading market to minimize the potential windfall to the receiving entities.[20]

## D. Auction revenue distribution

If and when a cap-and-trade market for emission allowances begins in California, there will be a single auction market that covers the allowance sale for multiple sectors. Operating in parallel will be a single trading market that allows any parties to buy and

[20] Assuming that each allowance issued is tagged with a serial number, allowances issued to a deliverer can be easily tracked and voided if necessary.

sell allowances. Some parties have advocated that auction revenues from a given sector should be returned to benefit that sector. While intuitively this seems to make sense, in reality this might create an unfair advantage to entities that choose to buy allowances in the secondary market since they will be barred from claiming any part of the auction revenue. DRA does not have any specific recommendations at this time on the apportionment of the auction revenue across the covered sectors.

In terms of the use of auction revenue within the electricity sector, DRA advocates that the revenue should primarily be returned to electricity ratepayers to lower the cost impact of carbon regulations. Part of the auction revenue should be used to pay for the administration of the allowance auction and to fund the operation of a Market Oversight Board; however the percentage of the auction revenue used to support such administrative functions should be capped. The state of Maryland, for example, is currently considering legislation that limits the use of auction revenue for administrative purposes at 3.5%.

The issue of auction revenue disposition within the electricity sector can be as contentious as the allowance allocation issue. Given the complexity of this issue, DRA recommends that the Joint Commission continue working with the ARB beyond the August decision to determine how to return auction revenues to benefit electricity ratepayers.

## E. Legal Issues

### 1. Consistency with the Dormant Commerce Clause

The Commission has concluded that requiring delivers of electricity to surrender allowances based on the amount of GHG emissions associated with the electricity they deliver in California does not violate the dormant Commerce Clause.[21] The staff paper considers allocating allowances to deliverers on the basis of their historical emissions, allocating allowances to deliverers on the basis of their output; and auctioning allowances, as well as variations on those three methods. DRA proposes initially

[21] D.08-03-018, p.87, Conclusion of Law 19, p. 134.

allocating 75% of the allowances on the basis of historical emissions, auctioning the rest, and moving to 100% auction within five years. None of the allowance allocation options discussed in the staff paper, or DRA's proposal, appears to violate the dormant Commerce clause.

The Commerce Clause of the United States Constitution empowers "Congress …to regulate Commerce with foreign nations and among the several states."[22] By implication, the authority of Congress to regulate interstate commerce limits the ability of states to obstruct interstate commerce. This inferred limit on the ability of states to constrain interstate commerce is known as the dormant Commerce Clause, and its focus is preventing economic protectionism.[23] Courts use three standards in evaluating whether a state or local law violates the dormant Commerce Clause. First, a law that on its face discriminates against other states in favor of local economic interests is likely invalid. Second, a law that does not discriminate against out of state interests faces a balancing test articulated *Pike v. Bruce Church, Inc.*, in which the United States Supreme Court held that if a statute "regulates even-handedly to effectuate a legitimate local public interest, and its effects on interstate commerce are only incidental, it will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits.[24] Third, a law that regulates outside the borders of a state is an extraterritorial, and therefore impermissible, regulation. The proposals for allocating or auctioning allowances to power deliverers to cover the GHG emissions of the power they deliver in California survive scrutiny under each of these three standards.

None of the proposals for allocating allowances demonstrates a preference for California entities. Administrative allocation would either be based on historical emissions or output, not the location of the entity delivering power. Similarly, the

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[22] United States Constitution, article I, section 8, clause 3.

[23] *New Energy Co. of Indiana v. Limbach,* (1988) 486 U.S. 269, 273-4 "This 'negative' aspect of the Commerce Clause prohibits economic protectionism -- that is, regulatory measures designed to benefit in-state economic interests by burdening out-of-state competitors."

[24] 397 U.S. 137, 142 (1970.)

requirement that some or all of the allowances be purchased at an auction would apply to all deliverers of power to California, regardless of whether they are in California or elsewhere. The various proposals for allocating or auctioning allowances are therefore distinguishable from cases where the law or regulation in question demonstrated a preference for in-state economic interests.[25]

The proposals for allocating or auctioning allowances would be part of a comprehensive scheme for decreasing California's share of GHG emissions,[26] which is a legitimate local purpose. Under the *Pike* balancing test, a state rule that is not protectionist *per se* will be evaluated to determine whether it serves a legitimate local purpose and whether its effects on interstate commerce are incidental. The state rule will be upheld "unless the burden on commerce is "clearly excessive in relation to the putative local benefits."[27] The allocation or auction proposals would require deliverers of power to acquire allowances to cover the GHG emissions of the power they deliver to California, but the requirement to participate in an administrative allocation or auction of allowances does not appear unduly burdensome, especially given the magnitude of the problem it is designed to address.[28]

Finally, the allowance or auction requirements would not attempt to regulate out of state conduct. The auction or administrative allocation requirements would apply only to power delivered in California, and would therefore differ from than regulations in which states have impermissibly attempted to tie in-state liquor prices to out-of-state

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[25] *See e.g. Wyoming v. Oklahoma,* (1992) 502 U.S. 437, 440 (Oklahoma law that required Oklahoma coal-fired electric generators to burn a mixture containing at least 10 percent coal mined in Oklahoma was found invalid on its face); *New Energy Co.,* 486 U.S. 274; *(* a tax credit that applied only to instate producers of ethanol was deemed facially invalid); *See e.g., Fort Gratiot Sanitary Landfill v. Michigan* (1992) 504 U.S. 353, 359-68; *City of Philadelphia v. New Jersey* (1978) 437 U.S. 617, 628-629.*Hazardous Waste Treatment Council v. South Carolina* (4th Cir. 1991) 945 F.2d 781; *City of Philadelphia v. New Jersey* (1978) 437 U.S. 617, 628-629.

[26] D.08-03-018, Findings of Fact 22-27, citing California Health & Safety Code Section 38501.

[27] *Pike, supra,* 397 U.S. at p. 142.

[28] *Burlington Northern Railroad Co. v. Department of Public Service Regulation,* 736 F. 2d 1106 (9th Cir. 1985) (upholding requirement that company maintain station agents in remote areas despite the questionable efficacy of the requirement)

liquor prices, where the effect of a state law was to cause out-of-state firms to adjust their out-of-state transactions based on the law of another state.[29]

### 2. Requiring deliverers to purchase allowances is a regulatory method of reducing carbon, rather than a tax

Four of the allowance allocation options discussed in the staff paper would require entities delivering power in California to buy some or all of the allowances needed to cover the GHG emissions of the power they deliver in California. DRA's proposal would require entities to buy allowances to cover the GHG emissions of the power they deliver in California, beginning with 25% of the allowances needed for "grandfathered" entities in the first year of compliance, and transitioning within five years to 100% of the allowances needed for all entities.

While it is possible that the requirement that power deliverers (or other emitters) purchase allowances could be challenged as a "tax," it is likely that the required purchase of allowances would be ultimately construed as a regulatory measure for decreasing carbon, rather than a tax. The distinction is important, because "taxes" can only be enacted by a two-thirds vote of the Legislature.[30]

"Taxes are raised for the general revenue of the governmental entity to pay for a variety of public services."[31] Regulatory fees, in contrast, are imposed under the government's police power in response to a particular problem. In *Sinclair Paint Company v. State Board of Equalization*,[32] the California Supreme Court considered whether fees charged to manufacturers of lead-based products pursuant to the Childhood

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[29] See *e.g.*, *Healy v. Beer Institute* (1989) 491 U.S. 324, 328.

[30] *See* Cal. Const., art. XIII A, § 3.

[31] *County of Fresno v. Malmstrom* (1979) 94 Cal. App. 3d 656, 983.

[32] *Sinclair Paint Company v. State Board of Equalization* (1997) 15 Cal. 4th 866, 870; *see also Brydon v. East. Bay Municipal Utility District.* (1994) 24 Cal. App. 4th 178 (an inverted block rate structure, designed to discourage water consumption during a drought, was not a special tax, but was instead a reasonable method to achieve the state's goal of conserving water); *San Diego Gas and Electric Company v. San Diego County Air Pollution Control District* (1988) 203 Cal.App.3d 1132 (emissions-based method of apportioning Air Quality District's costs was a regulatory fees rather than a special tax.)

Lead Poisoning Prevention Act of 1991were in fact illegal taxes, because they had not been approved by a two-thirds majority of the legislature. The court concluded that the fees were "bona fide regulatory fees" because they were imposed "to mitigate the actual or anticipated effects of the fee payer's operations" and the amount of the fees was reasonably related to the adverse effects of the lead.

Requiring that emitters purchase allowances for carbon would serve a similar regulatory purpose as imposing a fee for lead. The Legislature, in enacting AB 32, recognized that global warming was a significant problem requiring immediate action:

> *"(a) Global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. The potential adverse impacts of global warming include the exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems."*[33]

AB 32 therefore authorized ARB to implement "a system of market-based declining aggregate emissions…that [ARB] determines will achieve the maximum technologically feasible and cost effective reductions of greenhouse gas emissions."[34]

If ARB adopts a system in which allowances are auctioned, it would be part of an overall regulatory regime for reducing greenhouse gas emissions in the most cost-effective manner, and the collection of auction revenue likely not be viewed as the primary purpose of the auction. A court reviewing a challenge that allowances purchased through an auction were in fact a tax would be more likely to conclude that allowances were a regulatory fee if the auction revenues were used for achieving the goals of AB 32.[35] Thus, the use of auction revenues to reduce capital gains taxes or

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[33] California Health & Safety Code § 38501(a).

[34] California Health & Safety Code § 38562(c).

[35] *See Northwest Energetic Services v California Franchise Tax Board*, 159 Cal. App. 4th 841, 857-858 (money collected from limited liability corporations that was intended to make up lost income tax revenue and was not used for a regulatory purpose related to its collection was a tax).

support new government spending for purposes unrelated to AB 32[36] would make it more likely that a court would find the requirement to purchase allowances was a tax and not a regulatory fee.

## IV. FLEXIBLE COMPLIANCE

### A. Overview of Proposal

Flexible compliance mechanisms provide important opportunities to keep the cost of compliance and, therefore the impact on ratepayers, as low as possible. DRA therefore supports the following flexible mechanisms and market structure for a cap-and-trade system:

- No limitations on participation or special rules for certain participants.
- A price safety valve. When triggered, additional allowances would be borrowed from future periods.
- The creation of a Market Oversight Board, empowered to make market adjustments if absolutely necessary to avoid serious market failures.
- Eventual linkage to other trading systems. However, linkage should be phased in once the Californian and other markets have been tested and reasonably harmonized.
- Use of offsets, as long as robust protocols are adopted to ensure the integrity of the system.
    - There should not be geographic limits or discounting of offsets.
    - There should initially be quantity limits, to be eased over time as the integrity of the offsets is proven.
    - Offsets from other systems should be accepted only if those offsets meet comparably rigorous standards as those adopted in California. Since California has not yet established its

[36] ALJs' Ruling Updating Proceeding Schedule and Requesting Comments on Emissions Allowance Allocation Policies and Other Issues, April 16, 2008, Appendix A, "Allocating Allowances in a Greenhouse Gas Trading System," National Commission on Energy Policy, p.10.

protocols, it is too early to specifically support acceptance of offsets from certain systems.

  - Periodic audits of the approval and verification processes should be undertaken to ensure real reductions are being made.

- A 3-year compliance period.
- Unlimited banking.

However, certain proposed flexible compliance mechanisms could undermine the environmental goals of the program. DRA therefore does *not* support the following proposed flexible compliance mechanisms:

- Borrowing of allowances by individual entities (although system-wide borrowing may occur by the administrating agency if the safety valve is triggered, as mentioned above).
- Compliance extensions.
- Alternative compliance payments.

## B. Scope of Market and Related Issues

### 1. Flexible Compliance Mechanisms Should be Adopted Under a Cap-and-Trade Program

As long as a cap-and-trade system is in place, flexible compliance mechanisms will provide opportunities for meeting AB 32 targets at a lower cost, regardless of the scope and design of that system. If a cap-and-trade program is adopted, flexible compliance mechanisms will be essential for minimizing the impact of carbon reductions on consumers.

Recommendations for a given flexible compliance mechanism may interact with recommendations for *other* flexible compliance mechanisms. For example, a very long compliance period length is less necessary if there is unlimited banking (or vice versa); meanwhile, a very high price cap may make the use of other mechanisms much more important. As a whole, however, these mechanisms will not be significantly influenced by other components of the market design.

Given the potential benefits of flexible compliance mechanisms, the Commissions should take this opportunity to issue meaningful recommendations to the ARB on how to implement them. DRA is conscious of the tight timeline under which the Commissions and ARB are operating. However, it is important to start the discussion on flexible compliance mechanisms now, so that parties may weigh in and begin debating options.

#### 2. Benefits to Ratepayers of Allowing Unlimited Participation

The market for emission allowances and/or offsets should not be limited to only entities with compliance obligations. Limiting participation could result in other entities financially backing allowance purchases, which would be difficult to monitor and correct. For example, a financial institution could front the financial costs of purchasing allowances, but have a covered entity be the one who actually purchases them. The source of financing is not always readily transparent. Attempting to track the source of funding of allowance purchases would add another level of administrative burden with unclear benefits. Restricting participation to covered entities invites non-transparent, underground activities to get around the rules.

Additionally, expanding the number of participants can help promote market liquidity.

Other trading systems – the Acid Rain Program, the $NO_x$ Budget Trading Program, the European Union's Emissions Trading Scheme – chose not to limit participation. To date, there is no evidence that the decision to allow unlimited participation harmed the trading programs.

The rules governing banking, offsets, and auctions should also apply equally to all market participants. Applying different market rules creates a more complex system, and simply gives participants incentives to try to work around the rules. In the interest of promoting transparency and a level playing-field, all participants should face the same trading rules.

### C. Price Triggers and Other Safety Valves

#### 1. A Safety Valve is Necessary to Protect Ratepayers

DRA supports the use of a price safety valve such that, when triggered, the regulating agency can "borrow" allowances from future compliance periods.

From the perspective of an entity that must purchase allowances, an uncapped allowance price adds a huge uncertainty to planning its operational cash flow. A transparent set of rules to prevent short-term spikes in allowance prices will help maintain a stable business environment. Given that GHGs are stock pollutants,[37] short term increases in emissions do not have a significant impact on long-term environmental damages. DRA therefore recommends that the ARB adopt a safety valve mechanism that would allow ARB the flexibility to borrow allowances from future compliance periods when allowance prices reach a certain threshold level. The additional allowances would be offered for sale at the price cap rather than being auctioned to the highest bidder.

DRA's proposed safety valve mechanism is similar to a borrowing mechanism.[38] However, in this case, the borrowing of allowances is done by the regulator, rather than the covered entities, to prevent covered entities from accruing an allowance debt. The total number of allowances earmarked for the subsequent compliance period is reduced by the number of borrowed allowances, such that the cumulative reductions over the two compliance periods would be the same. In other words, under this safety valve mechanism, the emissions reduction path between 2012 and 2020 could be altered, but the emissions budget, which is equal to the area under the curve of the emissions

[37] Stock pollutants are those that build up over time due to their longevity in the atmosphere. Because carbon dioxide emissions stay in the atmosphere for decades and thus have a cumulative effect, the level of emissions in any one year is not nearly as important as the overall quantity of emissions over a longer timeframe. In contrast, flow pollutants dissipate rather quickly. The level of emissions in any given year is important.

[38] A safety-valve mechanism could alternatively increase the total number of allowances rather than borrowing allowances from future periods. However, increasing the total number of allowances could threaten the environmental integrity of the cap-and-trade system.

reduction path, would remain unchanged.[39] DRA further notes that a recent Congressional Budget Office (CBO) study entitled "Policy Options for Reducing $CO_2$ Emissions"[40] concludes that a cap-and-trade program that includes a safety-valve and either banking or a price floor could be significantly more efficient than a program with an inflexible cap.

At the April 25, 2008, Program Design Technical Stakeholder Working Group Meeting, representatives of the Natural Resources Defense Council (NRDC) commented that an explicit safety valve as a cost containment tool is unnecessary given that AB 32 includes a built-in safety valve that allows the Governor to intervene in the event that allowance prices reach a level that may significantly impact the California economy.[41] Section 38499(a) of the Health and Safety Code, however, does not define the appropriate point of intervention by the Governor. This creates an uncertainty as to what constitutes an "extraordinary event" that would prompt the Governor to intervene. Furthermore, this provision does not preclude the ARB or a designated market oversight body from proactively preventing major economic disruptions due to runaway levels of allowance prices.

In the long term, repeated triggering of the safety valve would imply that the 2020 target for GHG emissions reduction would not be met. It would also mean that the cost of achieving AB 32 goals would be significantly greater than expected. Repeated triggering of the safety valve would warrant a reevaluation of the adopted trajectory for reaching the 2020 goal, and the effectiveness of the strategies used for reaching that goal.

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[39] The Emissions Reduction Path and Emissions Path are illustrated in Figure 1 of the ARB white paper on cost containment tools as background to the April 25, 2008 program design technical stakeholder meeting.

[40] "Policy Options for Reducing $CO_2$ Emissions," Congressional Budget Office, February 2008.

[41] Section 38499 (a) of the Health and Safety Code states that "In the event of extraordinary circumstances, catastrophic events, or threat of significant economic harm, the Governor may adjust the applicable deadlines for individual regulations, or for the state in the aggregate, to the earliest feasible date after that deadline."

DRA does not have specific recommendations on the appropriate level of the safety valve at this point, but notes that the CBO study suggests an allowance price cap based on the best available estimate of the benefit (or avoided costs) of GHG reductions. Put another way, the level of the safety valve could be based on the economic impact of GHG emissions under a "business-as-usual" scenario. The Stern Report[42] projects the long-term economic costs of unmitigated GHG emissions would cost at least 5% of the global gross domestic product (GDP) by 2050.[43] Assuming an increasing safety valve level over time to account for inflation and the increasing costs of GHG emissions reduction, the ARB could design the safety valve by either starting with a reasonable price cap in the beginning compliance period and escalating it over time, or working backwards using the long-term economic costs of unmitigated GHG emissions. Given the importance of the issue and the difficulty of establishing a proper level, DRA recommends that the ARB solicit further comments specifically on this issue.

DRA supports the creation of an independent oversight board, such as the Carbon Market Efficiency Board recommended in the proposed Climate Security Act (the Warner-Lieberman Bill) (S.2191). This board should monitor emission trading operations, and it should have sufficient authority to quickly intercede in the event of market manipulation or damaging changes in carbon prices. To ensure greater certainty and confidence in the market, the oversight board should not constantly attempt to 'fine tune' the market features; however, the board should have the power to adjust certain characteristics of the market (e.g., the safety valve or allowance trading rules), if necessary to prevent serious market dysfunctions.

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[42] "Stern Review Report on the Economics of Climate Change", published on October 30, 2006, was commissioned by UK Chancellor Gordon Brown in July 2005. The review was based on the assessment of climate science carried out by the Intergovernmental Panel on Climate Change in 2001and calculated that the dangers of unabated climate change would be equivalent to at least 5% of the global gross domestic product each year.

[43] The Stern Report concurrently recommends an investment of about 1% of the global GDP to avoid irreversible damage to the climate. (source: http://www.independent.co.uk/news/business/news/stern-warns-that-climate-change-is-far-worse-than-2006-estimate-810488.html)

### D. Linkage

#### 1. Overview

Linking trading regimes may ultimately result in the most efficient market for allowances and offsets, but there are numerous hurdles to realizing that goal. California must establish its own market and make sure it functions effectively before undertaking the additional step of linking with other market. Looming in the horizon are a potential WCI system and possibly a national system of cap-and-trade under the Climate Security Act. The issue linking California's market to other systems maybe subsumed by its integration within a regional or national system of cap-and-trade.

DRA recommends deferring the decision on future linkage to other markets until California's market is established and the future of regional or national cap-and-trade is more apparent. If the Commissions believe it is important to develop a recommendation now, then DRA believes that following considerations are important. First, any linkage should be based on careful harmonization of the two markets, using their protocols once the existing programs have matured. While in theory linkage can help achieve the most cost-effective reductions, there is also the potential to undermine the environmental integrity of the system if the linkage is not done carefully. In particular, different non-compliance penalties, unequal price caps, and different standards for offset projects could affect the overall emission reductions (discussed below). These programmatic characteristics must be reasonably harmonized before systems are linked.

#### 2. Linkage Could Improve Economic Efficiency

Linking systems can result in a more economically efficient outcome on the whole, even though the relative advantage enjoyed by one system's participants may be somewhat reduced by the resulting equilibrium achieved through linkage.[44] That is, the new equilibrium price should result in a lower total cost of compliance for the same

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[44] Burtraw likens this equilibrium outcome to the equilibriums ultimately reached through exchange rate arbitrage in monetary policy. "Managing Greenhouse Gas Emissions in California, Chapter 5: Lessons for a cap-and-trade program," Dallas Burtraw et al, The California Climate Change Center at UC Berkeley, at 17.

quantity of emissions reduction between the two trading systems.[45] In addition, if emissions allowance prices and price caps vary in the two different programs, arbitrage between the two systems would transpire to take advantage of the lower prices in one system. Thus, the emissions allowance traders from the system with the higher market price will benefit from the lower prices of the other system, thereby bidding up the market price in that system. In theory, an equilibrium price should ultimately occur between the two systems as the trading balances out. This principle is noted below:

> *If one program has relatively lower marginal costs, it would be expected to be an exporter of emission allowances and its marginal costs, and consequently the allowance price in that program, would be expected to rise. This should occur until the programs have a common marginal cost.*[46]

#### 3. Linking's Potential for Harmful Wealth Transfers Due to Disparity of Carbon Prices

While this equilibrium market price should in theory reduce the total costs between the systems, it will increase costs and rates for some consumers, in effect creating a wealth transfer between systems. DRA cautions that the pursuit of the most theoretically economically-efficient scenarios must be tempered by concerns of short-term economic impacts.

If California links to a system with a much higher market price for carbon, Californian consumers and businesses could face much higher carbon costs than they would in the absence of linkage. If, in the absence of linkage, one system has a significantly higher price than California's system (for example, $5/ton versus $35/ton), then there appears to be some economic inefficiency present. In theory, the overall efficiency could be improved in both systems by linking them. The prices converge at, for simplicity, $20/ton. While the linked system may be more economically efficient, the participants in California's system are now faced with significantly higher prices – 4 times higher than under a non-linked system. Consumers in California could face dramatically higher prices. The result would be a notable wealth transfer from one

[45] *Id.*

[46] *Id.*

California to another geographic area. The short-term implications of such a transfer must be taken into consideration when deciding whether to link systems. The market prices and volume of emissions allowances in each separate market should be carefully evaluated before linking systems in order to minimize this potential wealth transfer

### 4. Different Penalties of Linked Systems Could Compromise Environmental Integrity and Ratepayer Investment

If penalties or other sanctions are not comparable between the linked systems, "non-compliance is likely to be exported to the system with the lowest penalty level."[47] Consider two systems, A and B, where System A has a steep penalty for non-compliance and a high cost for emission reductions; and System B has a low penalty and low cost for emission reductions. If the systems are not linked, participants under both systems may face sufficient deterrence to noncompliance, and both systems achieve nearly 100 percent compliance.

However, if the systems are linked, and the price of carbon in A is higher than the noncompliance penalty in B, then there is incentive for participants in B to sell allowances to participants in A even if selling those allowances makes them noncompliant. That is, the revenue B receives from selling to A would exceed the penalties faced by B. In this situation, the environmental integrity of the system has been compromised.

### 5. Harmonization of Price Caps Is Important When Linking

Price caps in the programs can have a large impact on arbitrage and the final allowance cost. Consider two programs, A and B. The market price of allowances in A is $10/ton, and the price in B is $20/ton. If the systems are linked, then arbitrage will occur. If there are no price caps in either system, the price will rise in program A and

[47] Organization for Economic Co-operation and Development (OECD) Global Forum on Sustainable Development: Emissions Trading, Concerted Action on Tradable Emissions Permits Country Forum, by Sonia Peterson (OECD Emissions Trading Forum paper), OECD Headquarters, Paris, March 17-18, 2003, at 10.

fall in program B, until the allowance price reaches equilibrium in both programs (say, $15).

However, if program A has a price cap of $10, at which point it issues more allowances, and program B has no price cap (or one that is above its current market price of $20/ton), then the price in both systems will converge at $10/ton. Participants in B will purchase allowances from A. Allowances in Program A cannot rise above their current price level, so the administrator issues more and more allowances, until the price in B drops to $10/ton. The unfortunate result is that the supply of allowances has expanded so much that the environmental integrity of both systems has been compromised.

Similarly, if California decides to disallow any borrowing of allowances, but links to a system that has unlimited borrowing, California could limit its ability to make real, near-term reductions, as there could be incentive for the other system to simply borrow more and more allowances to sell to the California market.

#### 6. Effect of Different Standards for Offsets or other Protocols

Different program standards among the systems could undermine one system's environmental goals. All other things equal, a system that uses a greater amount of offsets will likely have lower allowance prices. If one system (system X) has weak standards for offset projects, then there is the potential for a large number of low-quality offsets to enter that system, driving its price down. If participants in another system (system Y) begin purchasing X's allowances to take advantage of the lower price, the price in X will begin to rise, giving further incentive to incorporate more, low-quality offsets. Again, the result is a lower overall price for allowances, but the actual reductions achieved will be compromised.

There are similar issues with different standards for other system components, such as monitoring and reporting of covered entities. Likewise, different standards for borrowing/banking and other flexible compliance mechanisms could result in transfer of wealth from one system to another, and encourage the expansion of total allowances granted depending on safety valve criteria.

### 7. Establishing Linkage Conditions

Initially, California should not link to other markets. The California system, RGGI, and the WCI are not yet up and running, and it would be risky to link to untested markets. Before deciding whether to allow linkage, ARB should establish certain conditions that must be met to link to specific system. These conditions might include:

- Carbon Price Assimilation
- Establishment of Similar Penalties
- Synchronization of Cost Containment Measures
- Harmonizing Standards for Offsets and Other Protocols

Ultimately, Californian consumers should not suffer the consequences of harmonizing systems with significantly disparate market prices for theoretical and unproven long-term gains in economic efficiency. Thus, a conservative approach with clear protocols for linking regional systems in the United States, as well as international systems, is critical in order to avoid imposing potentially greater costs on consumers for an already costly GHG mitigation program.

## E. Compliance Periods

### 1. Compliance Period Length

DRA supports a 3-year compliance period. Three years is long enough to smooth out annual variations in carbon demand over the compliance period, thus preventing spikes and dips in allowance prices. However, the period is still short enough to ensure that real reductions are being made early on, rather than postponing them.

The compliance periods should be the same for all entities, and the length should not change during the 2012 through 2020 period.

Without taking a position on the issue of staggered compliance periods, DRA recognizes some benefit to this approach. In any one year, one-third of the covered entities would be at the end of their compliance period. A staggered compliance period would prevent the situation where all covered entities must surrender allowances on the same day. It's possible that staggering the compliance periods could mitigate some issues with market power, since only a third of the entities would need to meet their obligations on the same day. Additionally, from an administrative standpoint, it may be easier for the overseeing body to annually oversee the compliance of one-third of the entities rather than oversee compliance of all entities only once every 3 years.

### 2. Compliance Extensions

Compliance extensions should not be granted. Extensions will postpone the reduction of emissions, and will not provide the proper incentives for covered entities to plan ahead and invest in GHG-reducing technologies, offset projects, etc. The reduction goals under the cap-and-trade component would be thus be delayed. Postponing climate change mitigation will allow the costs of emissions abatement to rise at an ever-increasing rate.

There is a number of other flexible compliance and cost containment mechanisms that DRA recommends to circumvent the need for extensions. If the use of offsets, banking, a reasonable price cap, and a multi-year compliance period are all employed, regulated entities will have flexibility in meeting their compliance obligations and have protection from severe economic harm. If, in spite of those flexible compliance mechanisms, an entity is still not meeting its compliance obligations, then it should have purchased additional allowances or investigated other ways to reduce emissions. Lack of planning should not be excused through granting of extensions.

## F. Banking and Borrowing

### 1. Banking of Allowances, Offsets, and Other Credits

Unlimited banking of allowances should be allowed. Banking will help smooth out price variations in the carbon market, as regulated entities can accumulate excess allowances in one year and use them in years where prices are higher and allowances scarcer. Banking also encourages entities to do more reductions earlier on.

Unlimited banking should extend beyond just carbon allowances, and apply to offsets and credits from other trading programs, to the extent that offsets and other credits are allowed under the California trading system.

If non-regulated entities are allowed to participate in the market (as DRA recommends), all banking and offset rules should apply to them as well. All market participants should be treated equally in the market. Developing separate protocols for different participates complicates the system and, in the end, may not yield additional benefits. Unequal rules merely provide incentives for participants to work around the rules to their advantage.

#### 2. Borrowing of Allowances Should Not Be Allowed

No borrowing of allowances should be allowed. Borrowing would allow covered entities to delay making their reductions and allow them to build up a debt of allowances. This situation carries the risk that the borrower may end up defaulting on their allowance debt, thus jeopardizing the program's ability to meet the overall reduction goals. At the same time, DRA and other stakeholders are advocating for other cost containment mechanisms that will make borrowing unnecessary.

### G. Penalties and Alternative Compliance Payments

DRA supports the use of a financial penalty that provides adequate incentive for regulated entities to meet compliance obligations. While DRA does not have a specific recommendation for a penalty level at this time, penalties in other trading systems provide a useful reference when considering the appropriate level. In the U.S. Acid Rain program, compliance was extraordinarily high (nearly 100%), likely in large part because the penalty for non-compliance was strict and set at $2000/ton of $SO_2$ in 1990, and adjusted annually for inflation ($3,152/ton in 2006).[48] For comparison, the initial market price for $SO_2$ varied between $65 and $150 from 1990 to 1994, and reached $300 per ton in 1998, when the penalty was $2,581.[49] Thus, the market price per ton of $SO_2$ was in the range of approximately 3.25 to 12 percent of the penalty from 1990-1998. Since then the market price has steadily increased to nearly 100% of the penalty value, at least as of 2006. Non-compliant entities are also required to make up for their excess emissions by offsetting them in the next compliance period. Although it is difficult to forecast the trajectory of carbon market prices, a similarly strict penalty structure should be considered for the $CO_2$ program.

Similarly, under the EU ETS, entities face a penalty tax of €40 per ton of excess $CO_2$ emissions in the first compliance period, and €100 per ton of excess $CO_2$ emissions in the second compliance period. Non-compliant entities are required to make up for excess emissions by offsetting them in the next compliance year.[50] For comparison, allowances in the first period reached about €33 before dropping to about €3; the allowances are currently trading between €20 and €30 per ton.[51] The penalty is thus

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[48] "Acid Rain and Related Programs 2006 Progress Report," United States Environmental Protection Agency (US EPA 2004 Progress Report), at 11.

[49] OECD Emissions Trading paper at 11.

[50] Philibert, Cedric and Julia Reinaud. "Emissions Trading: Taking Stock and Looking Forward," OECD Environmental Directorate International Energy Agency, 2004, at 14.

[51] "Market Overview," Chicago Climate Exchange web site, accessed May 30, 2008.

greater than the prevailing price of carbon in that system and serves as a deterrent to non-compliance.

However, under the RECLAIM program, regulated entities face penalties for non-compliance that may vary in size, if they are even administered at all.[52] Non-compliant entities under RECLAIM that are penalized may also incur additional fees up to $500 per day for every 500 to 1,000 pounds of excess emissions.[53] DRA does not support the uncertainty and variability of penalties in the RECLAIM program.[54]

DRA recognizes that certainty of penalties and other sanctions is just as critical as the size. A penalty structure that is predictable, certain, automatic, and easily enforceable is the best approach for the California cap-and-trade system. The threat or deterrence value of a penalty may be somewhat weakened if it is not administered consistently and with certainty. DRA therefore recommends the adoption of a penalty with the following features:

- In keeping with the successful $SO_2$ program and the EU ETS, the penalty should be sufficiently high enough to deter non-compliance, but not so high as to create unnecessary and excessive financial risk for market participants. This penalty should be adjusted for inflation each year.

- Non-compliant entities should be required to make up for their excess emissions in the next consecutive compliance period.

- This penalty should be administered automatically and uniformly, and may be subject to adjustment as needed to remain sufficiently greater than the market price for emissions allowances.

The ARB should convene a workshop to set rules for penalties and price caps to further discuss details and to develop a consensus on these critical market design matters.

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[52] Philibert, et al,2004, at 14.

[53] *Id*. at 20.

[54] According to the OECD, the RECLAIM program has had an 85-95% compliance rate. Though a successful program, it has experienced less compliance than the Acid Rain program.

### H. Offsets

Offsets provide strong opportunities for reducing the cost of emissions reductions. However, recent investigations of both the EU's Clean Development Mechanism and the voluntary offset market have raised serious concerns regarding the quality of offset projects. DRA emphasizes that the ARB should proceed carefully and develop strict protocols for offsets in order to ensure that any consumer funds used to purchase offsets result in real reductions.

#### 1. Use of Offsets

Properly certified offsets offer the potential for lowering the cost of complying with AB 32. Since it is the overall quantity of GHGs in the atmosphere that is important, the geographic location of emissions does not matter. If reductions can be made more cheaply outside of regulated sectors in California, then market participants should have the flexibility to do so.

An additional benefit of having an offsets program under AB 32 is that California's GHG policies would then be more aligned with other GHG reduction programs. The Kyoto Protocol, the Regional Greenhouse Gas Initiative (RGGI), and the proposed Climate Security Act ("Lieberman-Warner Bill") all permit the use of offsets. California may ultimately link to some of these programs, and the greater the similarities of the programs, the easier it will be to link them.

Because California has high GHG emissions overall, in-state reductions should be made. However, an offsets program will not interfere with in-state reductions. A potential cap-and-trade program will account for only a portion of GHG reductions under AB 32. Regulatory mandates such as energy efficiency and the renewable portfolio standard will likely account for the bulk of the expected emission reductions from the electricity sector; other proposed mandates would guarantee reductions in other sectors

#### 2. Types of Offsets and Geographic Limits

It is premature at this time to make recommendations on the types of projects allowed as offsets. A number of other offset programs – i.e. the Clean Development

Mechanism, the Regional Greenhouse Gas Initiative, the California Climate Action Registry – are currently involved in assessing projects and how to quantify their benefits. ARB should evaluate their protocols when deciding what types of offsets to accept. DRA recommends that the ARB separately convene a working group with interested stakeholders to review offset program design in these other systems and make specific recommendations to the ARB related to the types of offset projects that will count towards the reduction goals of AB 32.

Geographic limits should not be placed on offsets. Locations outside of California (and the United States) may offer the strongest opportunities for inexpensive offsets. While some co-benefits of local projects (e.g., reduction of criteria air pollutants) may make geographic limitations seem desirable, it is important to remember that different projects have different co-benefits that may advance other social or environmental goals. DRA recommends that the focus of offsets remain on lowering the cost of complying with GHG reduction strategies, and not get distracted by simultaneously trying to achieve other environmental goals that are being managed under other regulations.

As discussed earlier, regulatory mandates such as energy efficiency requirements, the renewable portfolio standard, and transportation-related reduction strategies will ensure that emissions are directly reduced within California itself. Given that a key condition for qualifying offsets is additionality, there may be limited offset opportunities within California.

### 3. Quantity Limits

Quantity limits are appropriate, particularly at the beginning. Quantity limits should be eased with time, as the integrity of the offsets is proven.

Even with strict verification protocols, integrity issues cannot be eliminated entirely, and quantity limits offer one way to mitigate the risks associated with uncertainty of real reductions. Discounting reductions from offset projects also offers a way to mitigate this risk. However, for purposes of eventually linking to other cap-and-trade programs, quantity limits are preferable to discounting.

The other major existing and proposed trading systems have set quantity limits for offsets. For example, under RGGI, offsets may comprise up to 3.3 percent of an entity's compliance obligation during a control period (if a stage one or stage two trigger occurs, this limit expands to 5 percent and 10 percent). Under the proposed Climate Security Act (the Lieberman-Warner bill), allowances may comprise up to 15 percent of an entity's obligation. Neither of these programs discount offsets.

The purpose of the quantity limit should be to guarantee the integrity of California's emission reduction efforts; that is, serve as a backstop in case unforeseen problems arise with offset integrity. Therefore, assuming the ARB does implement very strong verification protocols, quantity limits need not be overly strict.

A very strict limit on quantity could hamper the development of a robust offset market. If there are too few projects, then the market may lack the competition and experience that will ultimately drive improvements in offset projects. Additionally, the point of allowing offsets is to lower compliance costs, and if there are too few projects, their impact on overall compliance costs may be minimal.

Quantity limits should change over time. Quantity limits could be stricter in the beginning as verification protocols are evaluated. Then, as verification protocols are evaluated and improved, it may be appropriate to relax the restrictions. Thus, as California gains confidence in the integrity of the offsets, greater quantities could be allowed. The increased availability of offsets may coincide with a tightening supply of carbon allowances as the cap is reduced, helping to ease a potential rise in carbon prices.

#### 4. Offset Administration and Protocols

DRA's main recommendations for the administration of an offsets program are: (a) integrity should be the most important goal; (b) California should take advantage of the learning curve from other offset programs; (c) the acceptance of offsets from other trading programs (e.g., CDM or JI) should depend on the relative rigor of those approval processes compared to the protocols that California ultimately adopts; and (d) California should require a periodic audit process. The approval, quantification, verification, and monitoring processes are distinct, yet share the ultimate goal of guaranteeing integrity. Therefore, DRA's comments address all of these processes together.

#### a) Integrity should be the most important goal.

The integrity of offsets is of utmost importance. Clear and rigorous protocols must be developed in order to ensure additionality and permanence, and to prevent leakage. Throughout this Rulemaking, there has been strong support for high integrity of offsets among participating parties.

Often, the cost of verification is directly related to the strictness of verification protocols. DRA supports instituting an approval process that is as efficient and non-cumbersome as possible, but the integrity of the approval process must not be compromised.

#### b) California should learn from other offset programs.

DRA does not have specific recommendations at this time for the specifics of monitoring and verification protocols; however, California should draw on, and improve upon, the groundwork laid by the Kyoto Protocol, RGGI, and other offset systems. There is no reason to 'reinvent the wheel,' and some harmonization of protocols will lend to an easier integration of trading systems in the future.

DRA recognizes, however, that the protocols under these systems are not without flaws. For example, the integrity of the Kyoto Protocol's Clean Development Mechanism (CDM) has been recently questioned by several reports, most recently in an April 2008 study released by Stanford University that found that much of the current CDM offset market does not actually reflect real emission reductions.[55]

As with any new idea, there is a learning curve on implementing the specifics. Meeting the additionality requirement is often a subjective process, and can be easily manipulated if the verifying parties are not vigilant. California has the advantage of

[55] Wara, Michael and David Victor. "A Realistic Policy on International Carbon Offsets." Working Paper #74. Program on Energy and Sustainable Development, Stanford University. April 2008.

learning about some of these challenges before setting their own guidelines. A few examples of these challenges are:

- Subjectivity of additionality. For projects earning revenue from offsets, it is difficult to know whether a project would have occurred anyway without the offset revenue. Without knowing for sure what *would have* occurred under different circumstances, administrators may need to rely on the word of a company or government that they would not have otherwise funded the project without offset revenue – which introduces a clear conflict of interest. The specific criteria used to determine additionality is key, as is the degree of scrutiny of the verifier. Several recent assessments concluded that a significant number of CDM projects are in fact not truly additional, highlighting the need for far better protocols that are currently in place.[56]

- Subjectivity of enforcing protocols. Determining that a project meets certain criteria can also be quite subjective. For example, predicted returns on investment (which are often used to help determine additionality) are estimates, and can be easily manipulated by changing the inputs. It is important that the verifiers scrutinize how estimates are generated, rather than simply taking the word of a developer that a project is in fact additional.

- Pressures on 3rd Party Verifiers. It is tempting to equate a 3rd party verifier's seal of approval with a guarantee that a project meets all offset protocols. However, the CDM has recognized dysfunction in the verification system. Verifiers are paid by project developers with whom they may do future business, providing a disincentive for the verifiers to criticize a project.[57] This problem is amplified by the increasing competition within the verification service market.

- Questions regarding permanence. Even if good-faith efforts are made to guarantee the integrity of offsets, there will inevitably be risks involving the permanence of projects. For instance, a newly planted forest can be destroyed by fire. Political instability in a country could threaten the maintenance of a waste-to-energy project. Careful planning is necessary to address permanence challenges.

[56] Schneider, Lambert. "Is the CDM fulfilling its environmental and sustainable development objectives? An evaluation of the CDM and options for improvement." Oko-Institut, November 2007. Page 40. Available at http://www.oeko-institut.de/oekodoc/622/2007-162-en.pdf.

[57] Wara, et al, 2008.

When establishing the specifics of the offset programs, the ARB should consult published studies and reports on the effectiveness of, and areas for improvement in, the CDM and other programs (such as the ones footnoted in this document).[58]

#### c) Acceptance of offset credits from other programs should depend on the relative rigor of those programs' approval/verification protocols.

As California has not yet developed its own protocols for an offsets program, it is premature to decide whether or not to accept offset credits from other trading programs. As discussed above, integrity of California's offsets is very important. If California accepts offsets from a program with less rigorous protocols, then the integrity of California's system may be compromised. Thus, until California's own protocols are developed, it is impossible to assess whether offsets from other systems will meet standards of suitable rigor.

Offsets from the CDM and JI programs may well meet California's eventual protocols; however, as noted above, these offsets are not free from controversy.

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[58] Recent reports on this issue in the EU's Clean Development mechanism include:

Michealowa, Axel and Pallav Purohit. "Additionality Determination of Indian CDM Projects: Can Indian CDM Project Developers Outwit the CDM Executive Board?" University of Zurich, February 2007. Available at http://www.climate-strategies.org/uploads/additionality-cdm-india-cs-version9-07.pdf.

Schneider, 2007.

Wara, Michael. "Measuring the Clean Development Mechanism's Performance and Potential." Stanford University, Program on Energy and Sustainable Development. July 2006. Available at http://iis-db.stanford.edu/pubs/21211/Wara_CDM.pdf.

[58] Wara, et al, 2008.

Recent articles regarding voluntary offset markets in the US include:

> "Another Inconvenient Truth," *Business Week*. 26 March 2007. Fahrenthold, David and Steven Mufson, "Cost of Saving the Climate Meets Real-World Hurdles," *The Washington Post*, 17 August 2007. "Carbon *(Continued)* Connoisseur," Economist, 13 August 2007. Revkin, Andrew, "Carbon-Neutral is Hip, but is it Green?" *The New York Times*, 29 April 2007.

Approval of these offsets by California should not be automatic just because these programs are already established.

There is increasing support for federal oversight or national standards on offset projects. In March 2008, California Attorney General Jerry Brown asked that the Federal Trade Commission set guidelines for carbon offsets.[59] His request comes after growing concern about the integrity of the voluntary offset market. California should continue to watch how possible federal guidelines develop as the State sets its own protocols.

**d) Undertake periodic audits of the approval process.**

Evaluating the effectiveness of the verification and monitoring protocols requires review and evaluation to ensure that GHG reduction goals are being accomplished. Similarly, it would be useful to review how strictly the verifiers adhere to the protocols. California should establish a periodic review process to assess the integrity of the offset program. The administrative body responsible for approving offset projects should hire an independent auditor to randomly check the integrity of approved and existing projects. This process would help California assess whether established protocols are sufficient to ensure high integrity offsets, and help California identify ways to improve those protocols if necessary.

**5. Discounting of Credits**

DRA recognizes the advantages associated with discounting offset credits, but does not recommend doing so for California at this time.

Discounting credits could serve two purposes: (1) to mitigate potential issues with offset integrity and (2) to 'tip the scales' in favor of direct reductions in California. However, DRA believes the first issue could be addressed by strict protocols and quantity limits, and the second issue would be addressed by the regulatory mandates previously discussed that will force emission reductions to take place within California.

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[59] Gibbons, Valerie. "Brown calls on feds for carbon offset standards," *LegalNewsLine.com*, 28 May, 2008. Available online at http://www.legalnewsline.com/news/209421-brown-calls-on-feds-for-carbon-offset-standards.

RGGI, the CDM, and the proposed Climate Security Act do not discount credits. If California chooses to discount offset credits, it will be adding one more layer of complexity of eventually linking to one or more of these programs. Since the goals of discounting would be met through other means, DRA does not recommend discounting at this time.

### 6. Legal Issues

#### a) Allowing the use of offsets is consistent with reducing GHG emissions while "minimize[ing] costs and maximize[ing] total benefits to California."

As long as offsets, whether in California or elsewhere, result in GHG reductions that are "real, permanent, quantifiable, verifiable, and enforceable"[60] their use appears consistent with AB 32's directive that the ARB should develop regulations that reduce GHG emissions "in a manner that …seeks to minimize costs and maximize the total benefits to California."[61] Section 38505(b) of the California Health and Safety Code defines "[a]lternative compliance mechanism" as "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." Thus, the ARB should allow offsets from California and elsewhere only if it can develop stringent protocols that ensure the reductions are additional, permanent, and enforceable. If such protocols can be developed, then the use of offsets from places outside of California is consistent with the requirements of AB 32.

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[60] California Health and Safety Code Section 38562(d)(1).

[61] California Health and Safety Code Section 38562(b)(1).

### b) Limiting offsets to projects located only in California could raise issues under the dormant Commerce Clause.

As discussed previously, the dormant Commerce Clause is designed to prevent economic protectionism against out of state products. Although it may be possible to limit offsets to projects in California on the basis that they produce local co-benefits such as decreased criteria pollutants and enhanced water quality, the standard is difficult to achieve. California would need to demonstrate a compelling state interest that could be achieved through no less restrictive means.[62]

### c) Agreements to use offsets from other jurisdictions or link California with other markets must be crafted to avoid infringing the supremacy of the federal government.

The Compact Clause of the United States Constitution provides that no State, without the consent of Congress, shall enter into an agreement or compact with another State or foreign power.[63] The Compact Clause applies to agreements that could increase the political power of the States and potentially encroach upon or interfere with the supremacy of the United States.[64] If California attempted to enter into agreements with other states or countries to promote GHG reductions, including linking their GHG compliance regimes, if such agreements have the potential to infringe on the supremacy of the United States, they would be subject to challenges under the Compact Clause.

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[62] *Maine v. Taylor* (1986) 477 U.S. 131, ("Even overt discrimination against interstate trade may be justified where, … out-of-state goods or services are particularly likely for some reason to threaten the health and safety of a State's citizens or the integrity of its natural resources, and where 'outright prohibition of entry, rather than some intermediate form of regulation, is the only effective method of [protection].' [citation omitted])

[63] United States Constitution, Article I, Section 10, clause 3, states: "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."

[64] "The application of the Compact Clause is limited to agreements that are 'directed to the formation of any combination tending to the increase of political power in the States, which may encroach upon or interfere with the just supremacy of the United States.'" *New Hampshire v. Maine*, 426 U.S. 363, 369, quoting *Virginia v. Tennessee*, 148 U.S. 503, 519.

In *United States Steel Corp. v. Multistate Tax Commission*,[65] the United States Supreme Court considered a challenge to the Multistate Tax Compact, an agreement entered into by a number of states in order to (1) facilitate proper determination of state and local tax liability of multistate taxpayers; (2) promote uniformity and compatibility in state tax systems; (3) facilitate taxpayer convenience and compliance in the filing of tax returns and in other phases of tax administration; and (4) avoid duplicative taxation. The Compact created a Multistate Tax Commission. Member states retained complete control over tax collection, determination of tax liability, and all legislative and administrative action affecting tax rates. Member states were free to adopt or reject the Multistate Tax Commission's rules and regulations, and to withdraw from the Compact at any time. The Supreme Court therefore concluded that the Multistate Tax Compact did not require the approval of Congress, because it did not encroach upon the power of the federal government. Although it may have improved the ability of states to collect taxes from entities that existed in multiple jurisdictions, it did not enhance the power of member states in a way that infringed on the supremacy of the federal government.

If California enacts a cap and trade system for decreasing GHG emissions, and wishes to link eventually to other systems or enter into agreements to recognize offsets from other states or countries, such an agreement would need to be consistent with any existing federal law and could not increase the power of participating states at the expense of federal supremacy. Provisions to recognize offsets from other jurisdictions might be structured similar to reciprocal tax statutes, “which provide the paradigm instance of arrangements not deemed to require the consent of Congress,” since they “neither project a new presence onto the federal system nor alter any state's basic sphere of authority." [66]

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[65] 434 U.S. 452.

[66] 434 U.S. 452, citing Tribe, Intergovernmental Immunities in Litigation, Taxation, and Regulation: Separation of Powers Issues in Controversies about Federalism, 89 Harv. L. Rev. 682, 712 (1976)

## V. TREATMENT OF CHP

DRA does not have comments on CHP at this time, but may respond in reply comments.

## VI. NON-MARKET-BASED EMISSION REDUCTION MEASURES AND EMISSION CAPS

### A. Electricity Emission Reduction Measures

Beyond current mandates, DRA does not recommend additional programmatic or regulatory measures that for the electricity and natural gas sectors in order to fulfill the mandates of AB 32. As noted elsewhere in these comments, the Joint Commissions should avoid promulgating additional regulatory mandates to either complement or augment existing programs for the purposes of reducing GHG emissions until there is additional analysis to support the need for such regulatory program enhancements. The Joint Commissions and ARB should refrain from expanding existing core regulatory measures until it is demonstrated that doing so will assist in minimizing the costs of compliance with AB 32 or meet other policy objectives.

### B. Annual Emission Caps for the Electricity and Natural Gas Sectors

There is currently insufficient information in the record to recommend specific caps for the electricity and natural gas sectors. E3's modeling exercise provided cost estimates for electricity- and natural gas-related reductions; however, in the absence of similar information for other sectors, it is impossible to assess whether reductions will be relatively more or less expensive in the electricity and natural gas sectors. Therefore, the specific share of responsibility for which these sectors should be responsible cannot be determined at this time. DRA discusses this issue further in Section VII.

## VII. MODELING ISSUES – COMMENTS ON E3 RESULTS

### A. Overview

DRA has several concerns about the E3 modeling results and the work left to be done to ensure that electricity ratepayers are shielded from excessive rates under a multi-sector cap-and-trade system. While the E3 modeling exercise provides an estimate of costs under various alternative scenarios within the electricity sector, they constitute just one piece of the puzzle that will serve to inform the decisions about sector responsibility that have yet to be made at ARB. Thus, while these cost results represent a picture of the possibilities for the electricity sector, they do not give us insight into the least cost path of compliance with AB 32 mandates among the covered sectors.

### B. Results

DRA has evaluated the basic runs illustrated in the slides from the May 13th E3 Workshop, which essentially bear out and validate DRA's concerns with the costs associated with reductions. DRA has reviewed the Reference Case provided by E3 as a foundation and other saved scenario runs loaded into the E3 model. These scenarios maximize each of the individual demand- and supply- side regulatory programs to demonstrate costs and rate impacts. These runs demonstrate that more data is needed on the costs of emission reductions in other sectors before decisions can be made about expanding existing mandates. Specifically, DRA has reviewed the following scenarios:

- Total costs of mandated emissions reductions for California and the rate impacts for each LSE under a Business as Usual (BAU) scenario that relies on existing demand and supply-side regulatory programs only.

- Total costs of mandated emissions reductions for California and the rate impacts for each LSE in a scenario that relies on existing demand and supply-side regulatory program goals and a cap-and-trade system.

- Total costs of mandated emissions reductions for California and the rate impacts for each LSE under various renewables assumptions:

- Total emissions reduced, costs, and rate impacts under a 20% RPS.[67]
- Total costs and rate impacts through maximizing RPS to meet total emissions goals (to illustrate steepness of cost curve).
- Total emissions reduced, costs, and rate impacts for each LSE under a 33% RPS and 100% EE.[68]

- Scenarios that blend preferred resource program mandates and cap-and-trade at a variety of carbon prices in order to generate a total cost curve. The marginal cost of abatement on this curve may be a reference point for later determining the total quantity.

DRA comments on specific scenario results and provides key recommendations below.

**1. Net Cost of $CO_2$ reductions under the "33% RPS/High EE" scenario are significant and demonstrate that abatement options other than expanding RPS should be prioritized instead.**

DRA has focused on a comparison of the rate impacts of the 2020 Reference Case versus "33% RPS/High EE Goals" case (Revised Aggressive Policy Case. E3's workshop slides clearly demonstrate that a 33% RPS/High EE Goal scenario would be prohibitively expensive for ratepayers. Specifically, this scenario results in approximately 29.6 MMt $CO_2e$ reductions, which come at a 27% increase in utility cost and a 29% increase in rates from 2008. However, the 2020 Reference Case indicates that utility costs would increase 31% while rates would increase 13% from 2008, thus demonstrating that the Revised Aggressive Policy Case would reduce utility costs by 4% while increasing rates by 16% over the 2020 Reference Case.[69] Moreover, the Revised Aggressive Policy Case would increase customer costs by approximately $3.9 billion per year over the 2020 Reference Case, while utility costs would *decrease* by $1.4 billion per

[67] "Electricity & Natural Gas GHG Modeling: Revised Results and Sensitivities" (E3 May 13th Modeling Workshop Presentation), May 13th, 2008, at 24.

[68] *Id.*at 16.

[69] E3 May 13th, 2008 Modeling Workshop Presentation, at 14.

year.  Thus, pursuing these aggressive mandates means that ratepayers will experience significant increases in rates.

#### 2. Mandating a 33% RPS for the purposes of GHG emissions reductions would represent a significant ratepayer investment with very little return.

When evaluated in terms of costs per ton of emissions reductions, the Revised Aggressive Policy Scenario show that consumers would bear the brunt of this investment while utilities are, for the most part, protected.  Increasing RPS to 33% under the Revised Aggressive Policy Case would cost approximately $133/ton.  Furthermore, under the 2020 Reference Case, 21.1 MMt $CO_2$e are estimated to be achieved at a total cost of approximately $29/ton, which represents a $37/ton for consumers, and ($7) for utilities. Under the Revised Aggressive Policy Case, 29.6 MMt $CO_2$e can be achieved at $168/ton.[70]  In other words, the reduction of those last 8.5 tons comes at a very steep cost.

Given that consumers are already spending approximately $37/ton of reductions through existing mandates,[71] the "low hanging fruit" of emissions reductions have likely already been achieved in the electricity sector.  This raises the key question discussed further below: why should additional core program mandates be enforced when it is likely not the most cost-effective means of fulfilling AB32?

DRA makes the following conclusions based on these analyses:

### C. Conclusions

#### 1. The Joint Commissions and ARB should pursue the least-cost path to compliance with AB 32 between all covered sectors.

The determination of the California electricity sector emissions reduction burden depends on the ability of ARB to accurately model the costs of emission reduction

[70] *Id*. at 17.

[71] *Id.*

measures[72] in the electricity sector as well as other covered sectors under a prospective cap-and-trade program. Without a reliable estimate of the relative costs of emissions reductions in other sectors, it is not possible to determine the precise share of emissions reduction responsibility that should be imposed on the electricity sector. The E3 model outputs provide a snapshot of the costs of emissions reductions under alternative combinations of core measures and user-specified design elements for the cap-and-trade system. Although the E3 model cannot determine the cost-effective quantity of emissions reductions that should be assigned to the electricity sector, it can nevertheless illustrate regulatory scenarios in the electric sector in which the marginal cost of emissions abatement becomes prohibitively expensive.

Ideally, the ARB's Energy 2020 Model will assign emissions reduction responsibility per sector based on a reasonable estimate of the lowest marginal cost of emissions abatement between covered sectors. The Joint Commissions should ensure that the total emissions reduction responsibility on the electricity sector is allocated equitably to avoid overburdening electricity ratepayers. Currently, no reliable cost figures have been made available publicly for the purposes of determining the emissions reduction responsibility between the other sectors.[73]

The comparison of marginal cost of reduction is necessary to minimize costs under AB32. To assign reduction responsibilities to sectors via other means could result in higher costs. For example, assigning emissions reductions proportionally according to each sector's relative emissions could result in excessively high costs if one sector faces much higher emissions reduction costs than another. That is, just because a particular

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[72] Core measures include program mandates such as Energy Efficiency, Renewable Portfolio Standard (RPS), California Solar Initiative (CSI), the Low Carbon Fuel Standard (LCFS), Port Electrification, and Assembly Bill 1493 (Pavley), which require that auto makers develop a new line of vehicles that will emit 22% fewer emissions by the year 2012, and 30% fewer emissions by 2020.

[73] At the May 19, 2008 ARB Scoping Plan workshop, ARB representatives stated that they expect 60% of the total emissions reductions to come from core measures such as Energy Efficiency, RPS, the Low Carbon Fuel Standard, and the Pavley standards. Thus, it is apparently expected that the remaining 40% of reductions will come from the cap-and-trade market.

sector emits 25 percent of California's total GHG emissions does not mean that it should necessarily have to achieve 25 percent of the reductions if there is a more cost-effective way of assigning responsibility to that sector. It may be the case where some sectors should reduce only a small portion of their emissions, while others reduce a very large percentage of their emissions. However, without reduction cost estimates from other sectors, it is impossible to determine to appropriate responsibility of each sector.

### 2. Politics and ease of regulation should not compromise a cost-minimizing strategy to emissions abatement.

It may be tempting to assign a large portion of reduction responsibility to the electricity sector given that it has traditionally been more tightly regulated than other covered sectors, such as transportation. The high fixed costs and naturally monopolistic tendencies of the utility industry have long necessitated regulatory checks and balances. However, the Joint Commissions and ARB should resist increasing regulatory mandates and placing a disproportionate amount of emissions reduction responsibility on the electricity sector. Once the "low-hanging fruit" of emissions reductions have been achieved in the electricity sector, the cost curve for emissions reduction will steepen, and further mitigation will thus occur at ever-increasing prices to consumers.

### 3. It is premature and potentially very costly to increase regulatory mandates when it is not known whether it is even necessary to do so.

Increasing core regulatory mandates in the electricity sector without supporting evidence from ARB's modeling process is premature and will only serve to significantly increase the costs of compliance with AB 32 for all end-users in all covered sectors. In D.08-03-018, the CPUC finds that the "IOUs and POUs should be required to go beyond a 20% level of renewable electricity delivered."[74] However, according to E3's representation of modeling results, the market price of $CO_2$ would have to reach approximately $160 in order to achieve 34.3 MMt $CO_2$ in emissions reductions through a

[74] D.08-03-018, p. 39.

42% increased investment in in-state renewables alone.[75] This scenario would apparently result in a nearly 50% increase in total costs, and an estimated 28% increase in rates from the 2008 Reference Case.[76] DRA reiterates that other core measures among the covered sectors may be able to achieve reductions more cost-effectively. For instance, preliminary cost studies from ARB estimate that the Pavley standards may result in approximately -$136/ton in 2020, thus ultimately resulting in long term cost savings to consumers.[77] The current ARB multi-sector modeling efforts for the purposes of finalizing the Scoping Plan should provide a more current, detailed examination of costs and benefits associated with this initiative.

The ARB is in the process of utilizing economic models, including Energy 2020, EDRAM, and The Berkeley Energy and Resources (BEAR) Model, in its development of explicit sector responsibility.[78] The BEAR model illustrates the costs of emissions reduced as well as the total economic costs and benefits of particular emissions reduction scenarios. Forecasts from the BEAR model reveal that there are numerous emissions reduction measures that will result in net benefit to the state economy while going a long way toward emissions reduction goals.[79] Until the Energy 2020, EDRAM, and BEAR modeling outputs are vetted, finalized, and published in the ARB Draft Scoping Plan, there is simply no basis for the Joint Commissions to recommend increased mandates in the electricity sector.

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[75] *See* E3's workshop presentation, "Electricity & Natural Gas GHG Modeling," (E3 May 13th Workshop Presentation), May 13th, 2008, at 24.

[76] *Id.*

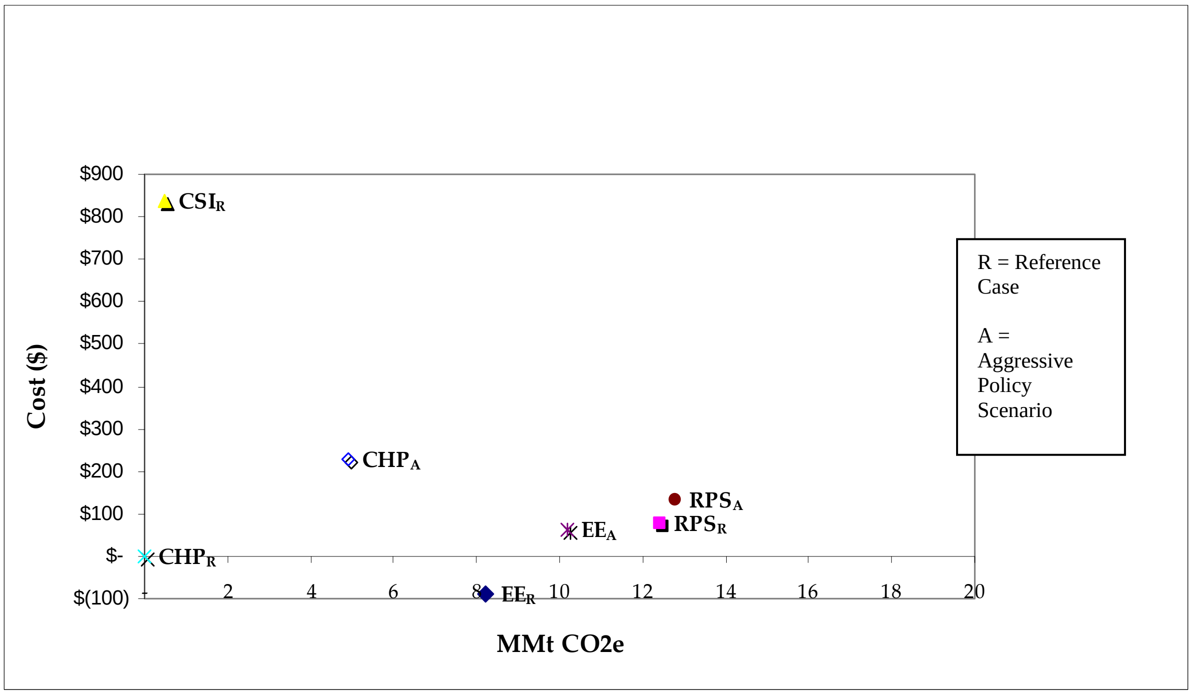
[77] "Staff Proposal Regarding the Maximum Feasible and Cost Effective Reduction of Greenhouse Gas Emissions from Motor Vehicles," California Air Resources Board, June 14, 2004, at vii.

[78] *See* "Economic Assessment for Climate Action in California: Overview of the BEAR Model" (May 19th Scoping Plan workshop slides), David Roland-Host, at 17-21.

[79] Roland-Host, David, Alexander E. Farrell, and W. Michael Hanneman. "Managing Greenhouse Gas Emissions in California," The California Climate Change Center at UC Berkeley, January 2006, at ES-3 and ES-4. Building efficiency, vehicle emission management, cement manufacturing efficiency measures, afforestation, and other measures are projected to result in significant emissions reductions and benefits to the economy.

The simple schematic diagram below demonstrates the relevant concept that the different core measures/regulatory mandates across covered sectors will address emissions reductions at different cost levels.  In theory, the approximately 174 million metric tons of $CO_2$ ($MMTCO_2$) reductions required by 2020 should be achieved at the lowest possible point on the cost curve for each core measure.[80]

**Chart 1: Costs of Emissions Under Reference and Revised Aggressive Policy Modeling Scenarios**




Thus, the Joint Commissions should reject the expansion of mandated supply- and demand- side programs such as RPS for the purposes of reducing GHG emissions, given the potential for excessive rate increases associated with AB 32 implementation.

[80] The schematic chart includes modeled costs for just a few core measures and is for illustrative purposes only.  The "R" and "A" at the end of each data label refers to the Reference and Aggressive Case results, respectively.

## VIII. CONCLUSION

DRA appreciates the opportunity to comment in response to the May 20, 2008 ALJs' ruling, and respectfully requests that the Commission consider these comments in determining the best way to achieve the GHG reductions required by AB 32 at the lowest cost and least risk to ratepayers.

Respectfully submitted,

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June 3, 2008

## CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of **"CORRECTED COMMENTS OF THE DIVISION OF RATEPAYER ADVOCATES ON ELECTRICITY SECTOR RESPONSIBILITY, ALLOWANCE ALLOCATION, FLEXIBLE COMPLIANCE MECHANISMS, AND MODELING "** in **R. 06-04-009** by using the following service:

[ X ] **E-Mail Service:** sending the entire document as an attachment to an e-mail message to all known parties of record to this proceeding 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 June 3, 2008 at San Francisco, California.

/s/ JANET V. ALVIAR

Janet V. Alviar

**N O T I C E**

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address and/or e-mail address to insure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

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