BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies.	Rulemaking 06-04-009 (Filed April 13, 2006)

THE DIVISION OF RATEPAYER ADVOCATES' REPLY COMMENTS ON DESIGN ISSUES RELATED TO GREENHOUSE GAS EMISSIONS REGULATORY COMPLIANCE

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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 reply comments in response to the comments of parties on issues related to implementation of the greenhouse gas (GHG) reductions required by the California Global Warming Solutions Act of 2006 (Assembly Bill (AB) 32). DRA's reply comments address parties' analyses and interpretations of modeling inputs and scenarios, emissions allowance allocation methodologies, flexible compliance mechanisms, and the treatment of combined heat and power.

A. Ratepayer Costs Should be First Priority

DRA is greatly concerned that among the multitude of parties and their assorted analyses and recommendations, the substantial risk of high costs and rate impacts to consumers under any number of emissions abatement strategies has been somewhat lost in the shuffle when it should be priority number one. California's electricity ratepayers are likely facing a multi-billion dollar investment in a GHG emissions reduction program. In the absence of reliable carbon price forecasts under a prospective multi-sector cap-and-trade system, ratepayers face even greater risk and uncertainty. The Joint Commissions should ensure that ratepayer costs are not masked or distorted by erroneous modeling assumptions and results. In order to take advantage of the theoretical benefits of a cap-and-trade system, proper controls to protect ratepayers should be implemented, including a price cap to insulate ratepayers from carbon price volatility risk

B. A Loading Order for AB 32

Parties offer numerous detailed evaluations and critiques of modeling inputs and scenarios, but a consensus on assumptions and resulting costs has not and likely will not be reached. Ideally, the Joint Commissions will be able to determine a reasonable range of costs under alternative sets of assumptions, which will hopefully direct the ARB when a more complete picture of costs across the covered sectors is established. DRA urges the Joint Commissions and ARB to strictly adhere to DRA's chief recommended principle of cost minimization when ranking the emissions reduction measures across sectors. Politics and the feasibility of imposing regulations on a particular covered sector must not be allowed to manipulate and compromise a GHG emissions mitigation program, for this will only serve to increase costs to ratepayers. Therefore, DRA recommends the development of a loading order of GHG emissions reduction strategies, similar to the existing loading order for the electricity sector. This should be governed by cost-effectiveness as the primary vehicle for fulfilling the mandates of AB 32.

DRA addresses these concerns further in response to parties' analyses and recommendations below.

II. GENERAL ISSUES.

A. Momentum for a cap-and-trade program should not preclude consideration of other, potentially more cost-effective measures such as a carbon fee.

The Utility Reform Network (TURN) discussed an inherent problem with cap and trade for the electricity sector: the rate increase due to including the opportunity costs of allowances in the price of electricity.[1] This associated rate increase would result in windfall profits to generators at the expense of consumers if generators receive free allowances. This problem underscores the importance of DRA's recommendation that other emission reduction strategies – such as policy mandates or carbon fees – should be more fully vetted before adopting a cap-and-trade system. DRA is concerned that there is currently considerable momentum for a cap-and-trade system based on the assumption that such a program would achieve lower cost reductions. This may or may not be the case. When considering the rate impact from opportunity costs of allowances, administrative expenses, and other costs associated with a cap-and-trade system, it is unclear whether such a system would actually result in cheaper reductions compared to other reduction strategies. DRA is concerned that the momentum behind cap-and-trade is preventing other reduction strategies from being fully evaluated. Cap-and-trade may well

[1] TURN Opening Comments, p, 3.

offer cost-effective reductions, but cost savings are not guaranteed. Before recommending a cap-and-trade system and/or increased mandates over a carbon fee, the Joint Commissions should fully analyze all three options for their relative cost-effectiveness in achieving AB 32 goals.

B. The Joint Commissions should reject the proposal for a cap-no-trade system that does not capture the efficiency benefits of a secondary market.

TURN recommends instituting a cap, but not allowing trading of allowances.[2] One justification for this recommendation is that it would eliminate the market risks associated with speculators buying up allowances. DRA nevertheless respectfully disagrees with this proposed mechanism. Such a program design could potentially increase the overall compliance cost while providing unclear benefits.

Under a system where no trading is permitted, covered entities must purchase enough allowances ahead of time to cover their expected emissions. Even if auctions are held frequently, entities must predict their future emissions. If an entity underestimates its total emissions and is short on allowances at the end of a compliance period, it does not have the option to purchase allowances from a secondary market and would have to pay a penalty – which is presumably more expensive than the market price for carbon. If, on the other hand, an entity has over-purchased allowances, then it will not be able to sell its excess allowances. Even if entities are allowed to bank excess allowances, the allowances would represent an investment with a potentially low rate of return as capital would be tied up in allowances and unavailable for other investments. Had the entities been able to trade, the one with an allowance deficit could have purchased allowances and avoided penalties, and the one with excess allowance could have recovered some of its allowance costs.

There could also be a situation where an entity learns of a new technology to reduce emissions cheaply after purchasing the expected number of allowances to cover its

[2] TURN Opening Comments, pp. 5-13.

emissions. No matter how inexpensive those reductions would be, the entity would have no incentive to invest in the new technology until it has used its existing allowances.

Meanwhile, the benefits of prohibiting trading are unclear. Market manipulation, while possible in theory, has not been evidenced in existing environmental allowance markets. Additionally, speculators can help smooth out fluctuations in prices. That is, they purchase allowances when they are relatively inexpensive (thus driving up lower prices) and selling them later when allowance prices are high (thus driving down higher prices).

If the Joint Commissions determine that a cap-and trade mechanism is the most effective means of reducing GHG emissions in the electric sector, then in order to take full advantage of potential economic efficiencies, the Joint Commissions should reject TURN's proposal to prohibit trading of carbon allowances in a secondary market.

III. ALLOWANCE ALLOCATION

A. DRA supports the added evaluation criterion of "Avoidance of Unnecessary Risk" in the Joint Commissions' determination of an allowance allocation methodology.

Sacramento Municipal Utility District (SMUD) proposed two additional criteria for the evaluation of allowance allocation option: avoidance of unnecessary risk, and public confidence in the program.[3] There are many types of risks involved in the implementation of various GHG regulatory programs. SMUD alluded to the risk of grid reliability for the electricity sector and the financial risks faced by load-serving entities when there is a shortfall in emission allowances. These financial risks will ultimately be borne by ratepayers. Moreover, a failed cap-and-trade market in California might jeopardize the use of a cap-and-trade program by the federal government or other nations to reduce GHG emissions. It is therefore of utmost importance that, if the ARB decides to implement a cap-and-trade program, California proceed cautiously in order to avoid a statewide crisis akin to that experienced in the restructuring of the electricity market.

[3] SMUD Opening Comments, pp.8-9.

There are two proposed design elements in a cap-and-trade program that DRA regards as high risk: auctioning 100% of the allowances from the start of the program, and the potential for uncontrolled allowance prices. Limiting the size of the initial allowance auction and including a price safety valve would better protect ratepayers as California gains experience in a new market for carbon regulation. DRA elaborates on the need for a price cap in Section IVA.

B. An historical emissions-based allocation methodology would not delay reductions, nor set a poor precedent for the federal GHG reduction program.

PG&E stated in its opening comments that "[a]n historical emissions or grandfathering approach does not recognize prior investments made in zero or low-carbon technologies, and provides an incentive to delay such activities in the hope of accumulating more allowances. Adopting such an approach for AB 32 also would set a precedent in de-positioning California relative to other regions in the United States in the design of a federal program."[4] DRA disagrees that a grandfathering approach incentivizes covered entities to delay investments in low-carbon technologies.[5] As long as the base year for the historic emissions is established in a prior year, there is no incentive for an emitter to increase its emissions in order to be assigned more allowances. As the emission cap ratchets down over time, fewer allowances will be given to the emitters; it only makes good business sense to begin investing in low-carbon technologies in anticipation of the declining emissions cap. In its opening comments, DRA proposed establishing baseline emissions using average emissions between 2004 and 2006. This is consistent with the Joint Commissions' intent to ensure that there is no bias against market participants "based on their past investment or decisions made prior to the

[4] PG&E Opening Comments, p, 20.

[5] Calpine in its opening comments also wrongly assumed "a grandfathering approach would not provide any real incentive for efficiency improvements nor investments in cleaner, more efficient, generating technologies." Calpine Opening Comments, p.8.

passage of AB 32,"[6] while encouraging early actions to reduce GHG emissions in advance of 2012 when the AB 32 compliance period begins.

DRA further disagrees that an historical emissions-based allocation methodology adopted for California would set a poor precedent for the design of a federal GHG reduction program. While the Air Resource Board and the Joint Commissions are deliberating on the point of regulation for the electricity sector and the program elements of a potential multi-sector cap-and-trade scheme within California, several GHG reduction bills have been proposed at the U.S. Senate with varying levels of long-term reduction goals. Each of these bills includes an allowance allocation proposal that has been developed independently of the California model. It is speculative to assume that the allowance allocation model that California ultimately adopts will set a model for the national GHG cap-and-trade program. Nevertheless, DRA supports the need for California to participate in the federal process to ensure that a federal cap-and-trade program would recognize the early actions undertaken by California utilities and industries.

IV. FLEXIBLE COMPLIANCE

A. Price Triggers

1. A price cap is necessary to protect ratepayers.

While many parties supported a price cap on allowances, several parties argued against price caps due to fears that such a cap would undermine the environmental integrity of the program. Additionally, several parties argued that a price cap could mute the price signals that are necessary to encourage emission-reducing activities.[7]

DRA finds the latter argument especially unsettling. Demand for electricity is fairly inelastic in the short-term, and some activities that reduce emissions can take years to implement. The electricity sector is unable to quickly adjust to high prices in the short-term. The energy crisis demonstrated the economic disruption to both businesses

[6] D.08-03-018, p.7.

[7] E.g., Calpine Opening Comments p. 14, and Morgan Stanley Opening Comments p 6.

and individuals that can occur under rapidly rising electricity prices. Because climate change is a long-term problem, it is not prudent to subject California ratepayers to potentially severe economic harm in the short term.

A reasonable price cap is necessary to prevent serious economic disruption to the electricity sector. While the use of other flexible compliance mechanisms will help prevent runaway allowance prices, the safety valve should remain as a back up.

DRA also disagrees that a price cap will undermine the environmental integrity of the system, as suggested by NRDC/UCS, Morgan Stanley, and others. If the safety valve takes the form of system-wide borrowing from future allowance allocation, as DRA recommended,[8] then the overall 'carbon budget' of the market will not change. The WPTF recommends a similar structure to any safety valve adopted.[9]

NRDC/UCS contend that a price cap is not necessary as AB 32 already has an emergency mechanism built in to Health and Safety Code section 38599(a).[10] While Section 38599(a) authorized the governor the authority to adjust compliance deadlines, relying on this provision to protect the electricity sector would be unwise. Section 38599(a) gives the governor the option only of adjusting deadlines; meanwhile, other market adjustments, such as capping runaway prices, might be better solutions. As DRA noted in its opening comments:

> Section 38499(a) of the Health and Safety Code… 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.[11]

Thus ARB should institute a cap in as part of any proposed cap-and-trade regime, in order to protect ratepayers from the consequences of runaway allowance prices

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[8] DRA Opening Comments p. 24.

[9] WPTF Opening Comments pp. 12-13.

[10] NRDC/UCS, Opening Comments p. 21.

[11] DRA Opening Comments p. 25.

2. PG&E's "price collar" approach would impose a price floor on allowances and could result in unnecessarily higher costs of compliance.

PG&E recommended using a 'price collar,'[12] which is a combination of a price ceiling and a price floor. DRA appreciates PG&E's proposal, as it attempts to develop a strategy for managing volatility while providing more certainty for technology investment.[13] However, while a price collar or bracket may reduce volatility and perhaps increase investor confidence, it does so at the expense of ratepayers. DRA sees no advantage for ratepayers in setting a lower bound price for emissions allowances when reductions may be achieved at lower costs.

DRA respectfully requests that the Joint Commissions reject PG&E's recommendation. A price floor would serve to artificially raise the market price of carbon, imposing unnecessary costs on consumers. PG&E argues that the price floor would help provide more certainty for businesses considering investment in emission-reducing technologies. However, if the market price of carbon drops below the proposed price floor, the market has successfully found lower-cost solutions for reducing emissions, and therefore the more expensive investments may not be necessary. This situation should be considered a success. The price of carbon should not be kept artificially high for the purpose of subsidizing certain investments.

3. The price cap should be set at a level that closely approximates the marginal cost of emissions reduction across all covered sectors.

Although DRA would prefer for prices to remain as low as possible, setting the price cap too low could result in the unintended consequence of increasing costs of abatement in the long run. Under a price safety valve design recommended by DRA and other parties, the triggering of the safety valve would allow the administrator to borrow allowances from future compliance periods. Thus, the more times the valve is triggered,

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[12] PG&E, at 40.

[13] Opening Comments of Pacific Gas and Electric Company on Additional Issues Related to Implementation of AB 32 in the Electric and Natural Gas Sectors (PG&E Comments), June 2, 2008, at 45.

the fewer allowances that will be available in the future. This situation could ultimately jeopardize the attainment of the GHG emissions reduction goal by 2020. Moreover, given the theories proffered by experts that climate change is occurring at an increasing rate, putting off the mitigation obligation by borrowing from future periods will likely only make future compliance more expensive. A price cap that is too high, however, will not provide adequate cost containment. Thus, the level of the price cap must be carefully set.

In its comments, TURN proposes a cap on allowance prices at $30 under a single price auction with no trading. The basis for this proposed price cap is that it would generate approximately $3 billion per year to fund the low-income and energy efficiency programs.[14] There is not enough information at this point to determine whether this number is too low or too high; regardless, the price cap level should be based upon a balance between containing costs and ensuring environmental integrity. It should not be based on the amount of revenue it would generate.

Nevertheless, DRA agrees in principle with TURN's proposal insofar as it seeks to minimize costs and recycle auction revenue to ratepayers. While DRA does not at this time have a specific price cap level in mind, the price cap should not be dictated by the low-income and energy efficiency program budgets alone, even if the Joint Commissions and ARB decide to recycle and redirect auction revenue toward these programs. Furthermore, DRA recommends the development a price cap that closely approximates the anticipated marginal cost of emissions reduction across all covered sectors, although this information is not available at this time. More data is needed from the ARB's multi-sector modeling process for its Scoping Plan in order to assess the appropriate price cap level.

B. Linkage should be a long-term goal that must be approached with caution.

In general, commenting parties were in support of linkage. These positions are consistent with DRA's support for eventual linkage to other systems. However, few

[14] TURN Opening Comments p. 14.

commenting parties addressed the specific challenges associated with linkage, and DRA again urges the Joint Commissions to proceed with caution before broadly recommending linkage.

Three parties commented on some of the challenges DRA raised in its opening comments.[15] The Climate Trust noted that reduction goals and emission caps should be harmonized prior to linking systems,[16] and Powerex noted that without harmonization of rules and standards, participants could seek arbitrage opportunities to get around stricter rules in one system.[17] EPUC/CAC, meanwhile, warned that linkage with RGGI could result in California buying large amounts of allowances from RGGI[18] – in effect, causing a large transfer of wealth from Californian consumers to RGGI.

The extent that these potential problems will actually manifest is difficult to assess before the specifics of the market structures are determined. Therefore, DRA supports the Sempra utilities' statement that it is premature to make specific recommendations on linkage at this time.[19] While eventual linkage may be a valid goal, the Joint Commissions and ARB should approach linkage cautiously, and not make a decision on linkage until the issues have been thoroughly vetted.

C. Offsets are an important cost-containment tool, if the integrity of the offsets can be demonstrated.

Among commenting parties, there was wide support for the use of high-quality offsets. Several parties also encouraged a framework where development of offset projects prior to 2012 would be accepted in the system, so that early action is encouraged. PG&E specifically suggested that the process for developing offset approval protocols be expedited,[20] and EcoSecurities requested that a start date be announced from which

[15] DRA Opening Comments pp. 26-30.
[16] The Climate Trust Opening Comments pp. 14-15.
[17] Powerex Opening Comments pp. 12.
[18] EPUC/CAC Opening Comments p. 70.
[19] San Diego Gas & Electric Company and Southern California Gas Company Opening Comments p. 29.
[20] PG&E Opening Comments p. 59.

credits from projects would be eligible.[21] DRA supports these requests. Expediting the development of these protocols will help encourage those early actions to take place. In development of its protocols, ARB should announce a date after which projects will be eligible for credit under AB 32. Until the protocols are developed, however, offset projects should not be guaranteed credit under AB 32, as their additionality would be questionable. It is possible that some projects are currently being developed in anticipation of revenue from an AB 32 trading system, but since those revenues are in no way predictable or guaranteed before protocols are determined, the projects may well have been developed due to other motivations.

Several parties shared DRA's concern regarding the integrity of offsets, and stressed the need for a rigorous approval and verification process. The emphasis on the quality of offsets is vital to ensuring that ratepayer funds are used effectively. In opening comments, DRA recommended a periodic audit process of approved projects.[22] NRDC/UCS went a step further to recommend that verifiers be assigned to projects, rather than allowing project developers 'shop around' for verifiers.[23] DRA supports this recommendation, as it would help alleviate pressure on verifiers to approve less-robust projects for the purposes of garnering business.

DRA was concerned by EcoSecurities's comment regarding the 'spirit' of additionality. On page 12 of its comments, EcoSecurities noted:

> Critics of a standards based approach may argue that some projects deemed additional under [a benchmarking] method may have indeed happened anyway. This however, is missing the spirit of additionality which is to drive emissions reductions that go beyond business as usual. Clearly a project exceeding a specific benchmark, by definition, meets this standard.*"*[24]

Businesses have numerous motivations for reducing emissions beyond what *appears* to be business-as-usual, only one of which is to produce offset credits for

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[21] EcoSecurities Opening Comments p.13.
[22] DRA Opening Comments p.41.
[23] NRDC/UCS Opening Comments p. 27.
[24] EcoSecurities Opening Comments p. 12.

California's carbon market. Emission-reducing activities often save businesses money, help it comply with a regulation, and lower business risks. To protect the integrity of AB 32's goals, and to achieve truly additional reductions, the ARB should develop protocols that verify true additionality of emission reductions and not simply the 'spirit' of additionality.

D. Limits on Participation

Several parties suggested that market participation be limited to covered entities. Some parties, like PacifiCorp, expressed concern that speculators trying to profit off of rising carbon costs would create artificial scarcity by purchasing allowances, and then reselling them when prices are higher.[25] Dynergy noted that non-covered entities could purchase allowances and retire them so that they would no longer be available to covered entities.[26] DRA understands the concerns associated with letting non-covered entities participate, but believes that it would be extremely difficult to limit participation effectively, and therefore these concerns would be better addressed through other measures.

In opening comments, DRA argued that (1) non-covered entities could easily get around participation limits by purchasing allowances through covered entities; (2) a larger number of participants would increase market liquidity; and (3) not placing restrictions on participation is consistent with existing trading systems, such as the Acid Rain Program, the NOx Budget Trading Program, and the European Union Emissions Trading System. Comments from PG&E and Morgan Stanley support these positions, particularly the ease of evading any attempts to limit participation.

Both PG&E and Morgan Stanley note the difficulty of truly preventing non-covered entities from participating in the market. PG&E points out that there are low barriers to entry in the wholesale electricity market: "If an entity wishes to become a 'deliverer'…[it could do so] by purchasing a small quantity of electricity…and delivering

[25] PacifiCorp Opening Comments p.30.
[26] Dynergy Opening Comments p.16.

it to California."[27] Thus, it would be relatively easy for an entity that wishes to purchase and sell allowances to gain the classification of a 'First Deliverer' even if its primary business is not dealing in electricity. Morgan Stanley, meanwhile, echoed DRA's concern that excluded entities would simply contract with non-excluded entities in order to purchase allowances.[28]

The Sempra Energy Utilities acknowledge that it would be difficult to restrict participation in the secondary market, but recommends that non-covered entities be prevented from participating in auctions.[29] This restriction would in effect give covered entities the first opportunity to purchase allowances. This would not eliminate the low barrier to becoming a first deliverer, or prevent non-covered entities from providing financial backing to covered entities during the auction process.

Efforts to determine which entities are legitimately buying allowances for compliance purposes would likely be difficult and expensive.[30] DRA recommends that concerns regarding market manipulation and hoarding instead be addressed via other means. A price cap would help limit the incentive for market manipulation, as the allowance price could not exceed the predetermined cap. A market oversight board could monitor market activities and adjust market rules if market manipulation appeared to be a serious problem. Additionally, auction rules could limit the number of allowances a single entity could purchase in any one auction, a practice recommended by RGGI. While this auction design feature would not eliminate the risks of hoarding, it could help reduce the likelihood that any one entity could hoard allowances.

E. Alternative Compliance Mechanisms Should Not Be Allowed.

As discussed in its Opening Comments, DRA opposes the use of Alternative Compliance Mechanisms and is concerned that granting them will undermine the integrity of the emissions cap and ratepayers' significant investment in the California

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[27] PG&E Opening Comments p.45.

[28] Morgan Stanley Opening Comments p.5.

[29] San Diego Gas & Electric Company and Southern California Gas Company Opening Comments p.27.

[30] Morgan Stanley Opening Comments p.5.

GHG policy program. PG&E notes that "penalties and alternative compliance payments and remedies can and should be limited sufficiently to avoid effectively allowing entities to "opt out" of the market."[31] DRA believes that alternative compliance payments should not be allowed at all for this very reason. In addition, Edison also proposes that alternative compliance payments should be allowed as a "relief valve"[32] for obligated entities in which the alternative is the inability to serve firm electric load. DRA believes that there will be sufficient flexibility in the form of other compliance mechanisms in the prospective cap-and-trade market that such relief valves will not be necessary.

V. TREATMENT OF COMBINED HEAT AND POWER

DRA appreciates the thoughtful opening comments submitted by many parties on the treatment of combined heat and power (CHP) resources. DRA recognizes that CHP can provide cost effective GHG reductions. In CHP almost all of the heat created by fossil fuel use[33] is productively used. In contrast, electricity generation from a power plant is far less efficient with about half of the fuel being wasted as excess heat (boilers on the other hand are very efficient since they just move heat from a firebox to some fluid.) In its opening comments, EPUC gave an example where natural gas use is reduced 18.4% by CHP compared to electricity from a CCGT and heat from a boiler[34]. DRA notes that CHP is being used extensively in other countries. For example, Denmark presently generates one-half of its electricity from CHP, mainly due to the use of district heating.

Nevertheless, it is possible that some CHP systems may actually be less efficient (e.g. older CHP systems) or have higher emissions than the combined operations of a CCGT and a gas-fired boiler (e.g. coal-fired CHPs). DRA agrees with PG&E that "AB 32 policy should encourage market incentives for new, efficient CHP without creating

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[31] *Id.*

[32] Southern California Edison Opening Comments p.25.

[33] These comments do not use the term "combustion" in this context, because fuel cell CH&P doesn't burn its fuel.

[34] EPUC Opening Comments diagram on p. 51.

subsidies for inefficient CHP."[35] DRA further recommends that the Joint Commissions refrain from mandating a minimum level of CHP until the relative costs of emissions reductions from other sectors become known. As discussed earlier, the imposition of a mandate[36] could increase compliance costs for the electricity sector if there are in fact other lower cost emissions reductions alternatives from other sectors. DRA offers the following recommendations related to CHP resources under both a market-based approach and a mandated approach[37].

A. DRA recommends use of the double-benchmarking approach for both topping- and bottoming- cycling CHP.

Under a market-based approach, there should ideally be a equal costs per ton of GHG for CHP as for the two elements that it replaces, which is electric generation and heat production. Assuming that there is no administrative distribution of allowances and that the electricity, natural gas and industrial sectors are all covered under the same cap-and-trade program, then there is no need to make any special provisions for CHP resources. Under this ideal market condition, the decision to install a CHP or not would be driven by the market price of carbon, which can be used to determine the overall cost effectiveness of CHP compared to the separate electric generation and heat production.

However, special provisions for CHP resources are necessary if free allowances are allocated to generators who compete with CHP plants selling electricity. Under any free allowance distribution scenario, DRA supports the use of double benchmarking to determine the allowances.[38] Under a double benchmarking method, allowances given to the CHP would be based on the emissions associated with the electric production from a new CCGT and the heat production from a high-efficiency boiler. DRA advocates the

[35] PG&E Opening Comments p. 66.

[36] A CHP mandate would be similar to the existing renewable portfolio standard, which requires that a certain minimum percentage of the investor owned utilities' electricity sales be from renewable resources.

[37] Based on opening comments from parties, DRA interprets that the inclusion of CHP as an emissions reduction measure is synonymous with a CHP mandate.

[38] SCE at Opening Comments p. 35; CCC Opening Comments p. 13; EPUC/CAC Opening Comments p. 51,

Joint Commission use a heat rate of 6,916 Btu/kWh, which is the average CCGT heat rate adopted by the Commission in establishing the 2007 Market Price Referent for renewable technologies[39], and a boiler efficiency of 85%[40]. For the purpose of determining free allowance allocation, DRA recommends the use of double benchmarking for both the topping cycle and bottoming cycle CHPs.[41]

The double benchmarking method could apply to either an output-based or historic emissions-based allowance allocation methodology. In its opening comments, DRA supported a historic emissions-based allowance allocation methodology that transitions over time to a 100% allowance auction, with no free allowances given to new entrants. As long as allowances are freely distributed, DRA recommends that there be an allowance setaside for new CHPs to encourage continued investments in new CHPs.

EPUC/CAC, CCC and Indicated Cement Companies supported the creation of a separate sector for CHP to "further CHP development, ensure proper incentives for CHP operations, and ease administrative burden."[42] However, assuming that the Joint Commissions adopt a double benchmarking methodology to allocate allowances to existing CHP facilities and that special provisions are made to accommodate new CHP facilities, CHPs would not be disadvantaged compared to other generators and therefore there is no need to create a separate sector for CHP. A separate CHP sector would in fact create additional administrative burden by the potential need to establish separate baseline emissions and reduction goals for the sector.

DRA also recognizes the potential that the natural gas sector and/or industrial sector may be treated differently than the electricity sector under a cap-and-trade, such that the cost per ton of GHG in the electricity sector is different from that in the natural

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[39] The Commission adopted Resolution E-4118 in establishing the 2007 MPR that assumes an average CCGT heat rate of 6,916 Btu/kWh, which takes into account the impact of Higher Heating Value, degradation, dry cooling and starts/stops over the life of a CCGT plant.

[40] The boiler efficiency assumption of 85% is supported by CCC in their opening comments. In contrast, EPUC advocated using an 80% HHV efficiency for a boiler.

[41] EPUC supports using a marginal fossil emissions rate to allocate allowances to bottoming cycle facilities (p.55)

[42] EPUC/CAC Opening Comments p. 50.

gas and/or industrial sector. In this case, a methodology is necessary to allocate the GHG emissions created between the electricity and heat production. DRA proposes that the emissions from a topping cycle CHP be allocated based on the proportional output of electricity and heat.

For bottoming cycle CHPs, where excess heat from an industrial process is recycled to generate electricity, the electricity generated can be considered GHG-free. For simple bottoming cycle with no supplemental firing, DRA advocates that the electricity generated has zero GHG emissions. For bottoming cycle CHPs with supplemental firing, emissions associated with the electricity production should be limited to the fuel used to increase the temperature of the waste heat stream, which increases the overall efficiency of the electrical production system.

B. DRA cautions against a mandate that would grandfather a permanent advantage to CHP resources.

Under a CHP mandate, a minimum percentage of the state's electricity sales would be supplied by CHP resources, regardless of the price of CHP-sourced electricity until the minimum level is met. DRA recognizes that a CHP system would likely produce lower GHG emissions than the combined electric generation based on a CCGT plant and the heat production from a high efficiency boiler. Nevertheless, DRA cautions against the risk of setting a mandate based on a fixed percentage of the state's overall electricity sales. As the GHG reduction goals become more aggressive over the next few decades, it is conceivable that more and more electricity would be generated by low-carbon resources including renewables, nuclear, and clean coal technologies. Setting a mandate based on a fixed percentage of the state's overall electricity sales risks grandfathering an advantage to CHP resources, even while other low-carbon technologies become cost-effective generation alternatives. One possible solution is to set a mandate based on a percentage of natural-gas fired generation. Another solution is to include a price cap to CHP-sourced electricity.

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

A. Increasing the regulatory mandate for renewable procurement could burden the electricity sector with a higher per-ton GHG reduction cost than other sectors.

In the opening comments, multiple parties assert that the use of a cap-and-trade program to meet GHG reduction goals would eliminate the need for additional mandates.[43] This is largely consistent with DRA's recommendations in its opening comments that the Joint Commission should defer the expansion of mandates for the purpose of reducing GHG emissions until there is evidence suggesting that those mandates are the most-cost effective measures and would not occur without regulatory obligation.

Energy efficiency is one area where the latter qualifications may hold true. Many energy efficiency measures are cost-effective. However, given the cost-based ratemaking structure for the IOUs, the IOUs could pass through all GHG regulatory compliance costs to their ratepayers, with or without the implementation of energy efficiency programs. The motivation to minimize ratepayer costs from an IOU's perspective is simply not as strong as that of a publicly-owned utility (POU) given the very different governance structure of these two types of utilities. To the extent that energy efficiency is cost-effective, some administrative mandates might be necessary to capture those benefits.

However, not all programmatic mandates are appropriate under a broad-based cap-and-trade program. For example, cost-effective renewables may be adequately promulgated through market mechanisms. At this point, the GHG reduction costs in other sectors covered under a cap-and-trade program remain unknown. In-state renewable procurement is currently projected through the E3 modeling exercise to be an expensive GHG reduction measure at over $100/ton. If there are cheaper GHG reduction opportunities in other sectors, then the other sectors will be making the lower-cost GHG reductions. If GHG reduction turns out to be more expensive in the other sectors, then

[43] SCE Opening Comments p. 40-41; Western Power Trading Forum Opening Comments p. 25; SEU Opening Comments p.38; Morgan Stanley Opening Comments p. 19).

the market would provide the incentive for the electricity sector to go after all cost effective GHG reductions. As demonstrated by NRDC/UCS, renewable procurement could be a very cost effective means to reducing GHG emissions when natural gas prices rise above $14/MMBtu.[44] Assuming that the market follows a least-cost dispatch order, renewables would be dispatched in the absence of any renewable procurement mandate.

DRA reiterates that, if a cap-and-trade program is implemented, an increased renewable mandate may be unnecessary, and could in fact burden the electricity sector with a higher per-ton GHG reduction costs than other sectors. Unless the Joint Commissions have full confidence that increased renewables will be cost effective relative to other GHG reduction opportunities in other sectors covered under a cap-and-trade program, the Joint Commissions should not pursue an increased renewable procurement mandate.

VII. MODELING ISSUES

DRA appreciates the considerable amount work and time that E3 put into developing what should be viewed as an effective tool for evaluating the cost of reducing emission in the electricity sector. However, parties have identified a few constraints and possible inaccuracies in the model that cast doubt on forecasts of certain regulatory program costs as well as individual LSE costs and rate impacts relative to the Reference Case.

One of DRA's chief concerns with the modeling results and some parties' supporting analyses is that certain scenarios are favored because they shift significant costs and risk toward ratepayers. Nobody denies that emissions reductions will come at a substantial cost, but it is premature to increase particular mandates based solely on the E3 modeling outcome when there is not a complete picture of costs across all covered sectors. AB 32 mandates that emissions are reduced in the most cost-effective manner possible. The Joint Commissions should carefully consider rate impacts before adopting

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[44] NRDC/UCS Opening Comments pp.9-10.

a particular recommendation or proposal. Ratepayers should not be bear the brunt of the costs and risks associated with GHG emission abatement.

A. Modeling Results and Parties' Concerns

1. The concerns with the model's ability to accurately forecast cost and rate impacts of alternative scenarios underscore the need for strong cost containment mechanisms in a cap-and-trade system.

Although there are many potential benefits associated with a cap-and-trade system, there are numerous risks, complexities, and uncertainties that must be mitigated by cost containment mechanisms. Parties' analyses and interpretations of the E3 modeling results validate some of DRA's concerns and raise additional questions about the prudency of investing billions of ratepayer dollars in an untested market-based system. Unless sufficient controls are in place to protect ratepayers, DRA cannot support a system fraught with such uncertainty. Some of these concerns are discussed below.

2. Carbon price uncertainty handicaps the assessment of ratepayer risk and warrants the establishment of a reasonable price cap.

The model's inability to forecast carbon prices under alternative scenarios makes it difficult to develop reliable and reasonable cost containment measures. Thus, while the model measures a range of costs under different pricing scenarios, it cannot project actual carbon prices. DRA recognizes that carbon price forecasting is no small task, but cost modeling alone cannot accurately predict whether and to what extent those costs will be reflected in carbon market prices. Moreover, the model appears somewhat limited in demonstrating LSE cost and rate impacts at higher carbon prices. As observed by SMUD, the model "is very limited in its ability to make reductions in response to increases in carbon or natural gas prices."[45] Southern California Public Power Authority (SCPPA) also notes that "CARB does not yet have projections of either allowance prices

[45] SMUD Opening Comments p.36.

or the effect that projected allowance prices would have on the California economy."[46] However, as discussed at the May 19th scenarios workshop, CARB expects to have this information for its Scoping Plan. This current limitation in the Joint Commissions modeling process makes it challenging to establish an effective carbon price cap and to accurately assess the risk and costs facing ratepayers in a cap-and-trade system. As discussed in more detail elsewhere in this document, this uncertainty and risk merits careful monitoring and the establishment of a cap on allowance prices based on the marginal cost of emissions reductions.

3. Even under optimistic market transformation assumptions, increasing the RPS mandate still may not be the most prudent ratepayer investment when compared to other emissions reduction alternatives across covered sectors.

Some parties have argued that the natural gas prices and market transformation assumptions in the model mischaracterize the projected costs of renewables. SMUD, NRDC, TURN, LADWP, and several other parties note that gas prices are higher than the $7.85/MMBtu included in the modeling assumptions. NRDC observes that the "33% RPS/High EE" scenario would result in an approximately 20% reduction in demand for natural gas over the Reference Case, which could result in lower gas prices.[47] NRDC also notes that the model fails to reflect the benefits to load of increased transmission investments, which would also reduce the cost of proliferating renewable generation.[48] Furthermore, NRDC's revised "33% RPS/High EE" scenario (Alternate Modeling Scenario) would result in approximately 29 $MMtCO_2e$ fewer emissions, or an average incremental cost of $45/ton.[49]

DRA appreciates the analysis and alternative vantage point provided by NRDC/UCS, and is open to the possibility that some of the modeling assumptions may

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[46] SCPPA Opening Comments p. 8.
[47] ZNRDC/UCS Opening Comments p. 46.
[48] *Id.*
[49] *Id*. p. 51.

overstate the cost of renewables. In particular, the model should include higher natural gas prices in order to avoid the distortion of the costs of renewables relative to other generation. Nevertheless, questions still remain about the certainty and extent of market transformation, and the costs borne by consumers under the NRDC/UCS Alternate Modeling Scenario. NRDC's projected incremental cost of emissions abatement is built around revised input assumptions that may or may not be feasible.[50] Even under this alternate scenario, there are still $4.82 billion in consumer costs and $2.66 billion in utility savings under NRDC's Alternate Modeling Scenario relative to the Reference Case.[51] Furthermore, even if this Alternate Modeling Scenario is deemed reasonable, other emissions reduction measures among the covered sectors may be less costly for California ratepayers and should thus be prioritized based on the lowest cost per ton reduced.

4. LADWP's analysis of modeling scenarios without a cap-and-trade system ignores potentially significant consumer costs and rate impacts.

LADWP's chart showing the rate impacts, emissions reductions, and costs requires some clarification in order to be put into its proper context. While LADWP purports that its preferred "33%RPS/High Goals EE" modeling scenario (Aggressive Policy Case) might have a cumulative savings of $6.9 billion and achieve more emissions reductions over the Reference Case, it would do so at a 13.8% average rate increase over the Reference Case, and a 29% rate increase over 2008 rates.[52] Based on the Aggressive Policy Case in the E3 Calculator, DRA has verified that 2020 ratepayer costs increase by $5.2 billion over the Reference Case.[53] Of the 18 different scenarios summarized in LADWP's Table 2, the Aggressive Policy Case would result in the second largest rate increase. This is second only to Case #27: the 100% auction scenario, which would

[50] *Id*. p, 50.

[51] *Id. See* Table 2: Emissions and Cost Impacts of NRDC/UCS Alternate Modeling Scenario, at 51.

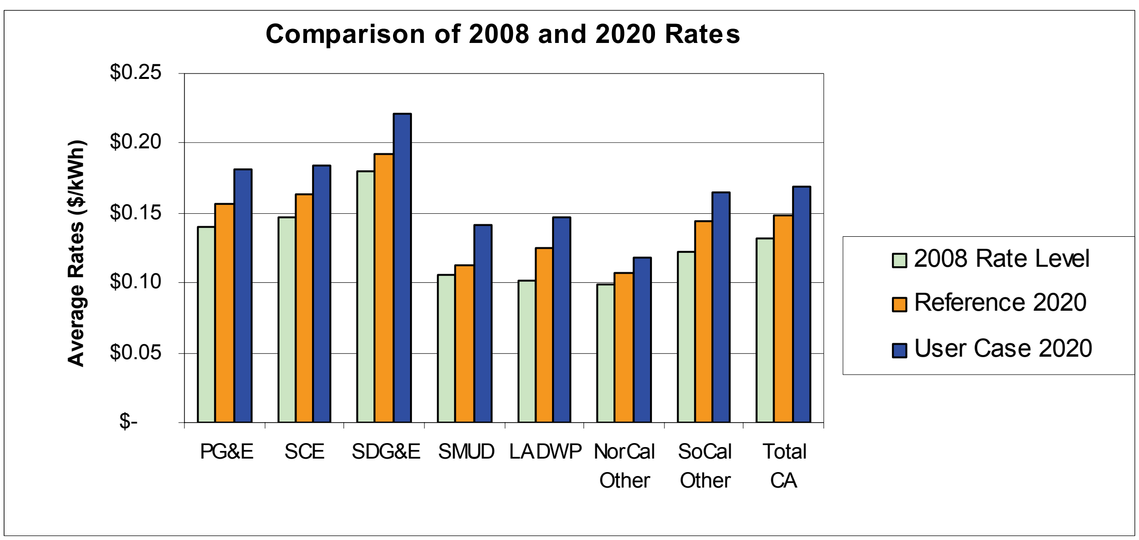
[52] See summary results of "33% RPS/High EE Goals" scenario loaded in E3 GHG Calculator v. 2b, Resources tab.

[53] *Id*..

result in 290.7 additional tons of emissions reductions over the Reference Case, or approximately 113 additional tons over LADWP's preferred Aggressive Policy Case, but at a cumulative cost of $53 billion. Omitted from this analysis is what will be done with the auction revenue, which could be allocated at least in part to LSEs to offset their costs associated with various auction scenarios. This makes it difficult to compare the cumulative costs associated with the Aggressive Policy Case to the auction-based scenarios.

These cumulative cost "savings" over the Reference Case are therefore misleading when the net result is a generally significant increase in costs and rates to California consumers. Furthermore, LADWP's rates rise from approximately $0.10/Kwh to $0.147/Kwh, but they still remain among the lowest rates in the state under this scenario.[54] Regardless of whether AB 32 emissions reductions come from regulatory mandates, cap-and-trade, or both, they will come at a significant expense to ratepayers. While it is easy to see why this Aggressive Policy Case would be attractive to LADWP compared to the alternatives, their analysis ignores the true costs of emissions reductions under this scenario for all of California's ratepayers.

Chart 1: Comparison of 2008 Rates to Reference and "33% RPS/High EE Goals" Cases[55]



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[54] E3 Revised Model, "33%/High EE Goals Output."

[55] The "User Case 2020" refers to the "33% RPS/High EE Goals" Case or Aggressive Policy Scenario.

VIII. CONCLUSION

DRA requests that the Commission consider DRA's comments in determining the best way to achieve the GHG reductions required by AB 32 at the least risk and lowest cost and to ratepayers.

Respectfully submitted,

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June 16, 2008

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of **"THE DIVISION OF RATEPAYER ADVOCATES' REPLY COMMENTS ON DESIGN ISSUES RELATED TO GREENHOUSE GAS EMISSIONS REGULATORY COMPLIANCE** 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.

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Executed on June 16, 2008 at San Francisco, California.

/s/ ROSEMARY MENDOZA

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ROSEMARY MENDOZA

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