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 Practices.	Rulemaking 06-04-009 (Filed April 13, 2006)
	And
[Also filed at California Energy Commission]	*CEC Docket 07-OIIP-01*

COMMENTS OF THE INDEPENDENT ENERGY PRODUCERS ASSOCIATION ON EMISSION ALLOWANCE ALLOCATION, FLEXIBLE COMPLIANCE, AND COMBINED HEAT AND POWER

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Pursuant to the schedule established in the Administrative Law Judge's Rulings Requesting Comments on (a) Emission Allowance Allocation Policies and Other Issues, dated April 16, 2008, (b) Combined Heat and Power, dated May 1, 2008, (c) Flexible Compliance Policies, dated May 6, 2008, and (d) Emission Reduction Measures, Modeling, and Other Issues, dated May 13, 2008, the Independent Energy Producers Association ("IEP") submits its comments on those topics and its responses to the questions posed in those rulings. IEP's responses to the individual questions posed in the rulings are contained in Attachment A. In addition to commenting on the specific questions raised by the rulings, IEP provides comments on greenhouse gas ("GHG") emission allowance allocation policies in light of the "Joint California Public Utilities Commission and California Energy Commission Staff Paper on Options for Allocation of GHG Allowances in the Electricity Sector" ("Joint Staff Paper"), attached to the April 16, 2008 ruling.

I. SUMMARY

In Decision 08-03-018, the Commission and the California Energy Commission ("CEC") recommended that "deliverers," defined as in-state electric generators and the entity owning imported power when it is first delivered to the California electrical grid, should be the point of regulation for the GHG emission reductions required by Assembly Bill ("AB") 32. As recommended "points of regulation," carbon-emitting electric generators effectively have two means to comply with the GHG emission reduction program in the short-run.[1] Specifically, they may (a) acquire allowances that represent a "permit to emit" a ton of carbon associated with their actual operations in real-time to comply with contractual obligations or maintain electric grid reliability, or (b) reduce operations and the production of electricity that would otherwise serve demand. Unlike other regulatory programs addressing pollutants (e.g. SOx and NOX), where technological fixes were available to reduce targeted emissions, the GHG emission reductions program lacks any technological solution that can immediately be retrofitted onto a facility to remove carbon emissions.

Importantly, electricity is not like many other commodities. First, it does not lend itself to efficient storage. As a result, it is imperative, from a grid reliability perspective, that some electrical generators be available to operate in real-time at a minute's notice. Second, electrical generation infrastructure is planned and sized to match projected demand. Other than required Operational Reserves and a Commission-prescribed Planning Reserve Margin, generation infrastructure is planned to match peak demand. This means that most generation is required to

[1] In the long-run, the sector as a whole can effectively meet GHG emission reduction goals by transforming the electric generation fleet from relatively high emitting resources to relatively lower emitting resources. For example, some renewable generation (e.g. geothermal and biomass) can operate as baseload resources and replace coal. This fleet transformation, however, requires time and resources, and it must be accomplished while maintaining grid reliability.

remain available during the year to ensure overall grid reliability by matching supply with the daily fluctuations in demand. Little margin for error exists.

Accordingly, if generators are designated as the "point of regulation," electric generators and their operations must be accommodated in the AB 32 program in a manner to ensure that the reliability of the electrical grid is not threatened. To advance the paramount goal of maintaining reliability, the overall program design must assure the following:

- **Electric generators must have direct access to the allowances needed to maintain the reliability of the electrical grid and to serve load.** From an electric generator perspective, the allowance is a "permit" to operate. It makes no sense, and it is risky public policy, to disconnect the "points of regulation" from the "allowance allocation" as has been theoretically suggested.[2] Denying generators access to necessary allowances at the point of release from the appropriate regulatory body risks undermining the operational requirement to match generation operations to daily fluctuations in demand; hence, it risks overall grid reliability.
- **Electric generators must have "flexible compliance tools" available to enable them to match allowances with real-time operations.** Electric generators have an obligation, established in FERC-approved tariffs, to make their units available to transmission system operators to ensure grid reliability. Effectively, electric generators no longer control their operations 100 percent of the time. Flexible compliance tools are necessary to enable a generator to match allowances to required operations.

[2] "[I]t does not necessarily follow that allowances must be granted to the deliverers if they are administratively allocated. It is possible that allowances (or their value) could be granted to regulated or publicly-owned retail providers of electricity on behalf of their consumers." Joint Staff Paper, at p. 7.

- **Electric generators must have a reasonable means to recover the costs of acquiring allowances**. Because GHG allowances essentially are operational expenses (much like fuel), the cost of acquiring allowances necessary to generate electricity in real time must be recoverable by the owners. Of particular note, many electric generators, who are operating under *existing* contracts for which the cost recovery of GHG allowances was not contemplated, may not have available a means to recover this added operational expense. For example, most Qualifying Facilities ("QFs") and some electric generators operating pursuant to existing Tolling Agreements fall within this group. While this is a temporary, transitional problem, it effects the operations of a significant percent of the current generation fleet including renewables and cogenerators, the continued operations of which is critical to achieve the GHG emission reduction goals.

Cap and trade ("CT") programs can be an efficient means to lower the cost of regulatory compliance. IEP generally supports CT programs as means to achieve regulatory compliance at a lower cost than would otherwise occur. However, IEP's support for a CT program is conditioned on the following:

- **The CT program must be liquid and multi-sector**. A liquid, multi-sector CT program will have a tendency to dampen price increases and volatility in the market for allowances. Excluding the transportation sector as proposed by the Western Climate Initiative ("WCI"), excluding the natural gas end-use sector as proposed by the Commission, and omitting any other key sectors emitting GHG effectively narrows participation in the CT program to the electric sector only. If participation in the CT program is limited to only the electric sector, then the value of the CT program will be significantly lowered because lower cost, GHG efficiency benefits achievable in other sectors are excluded from the program.

- "**Revenue recycling" to mitigate retail rate impacts ultimately results in relatively lower emitting electric generation units subsidizing relatively higher emitting generation units**. Implementation of AB 32 cannot and should not result in the subsidization by lower-emitting resources of the higher-emitting generation resources that should be targeted for reduced operations or retirement. This outcome would make a mockery of the legislation as not real change in the generation resource mix or dispatch order would occur. Is this the message that California wants to send to the investment community?
- **Masking the cost of carbon emission reduction (via "retail rate mitigation") disconnects retail consumers from wholesale prices**. The Joint Staff Paper was particularly concerned about the effect on retail rates of carbon-reduction requirements of AB 32. While IEP has no desire to subject retail consumers to higher rates, efforts to shield consumers from the implications of a "carbon-free" economy in the short-term will backfire and lead to higher costs in the future. Meeting the goals of AB 32 will require the transformation of the California economy that in turn will require significant technological innovation coupled with behavioral changes. Retail prices are an extremely effective means to stimulate change and innovation and to affect behavior. An implementation strategy designed to simply shield retail consumers from higher wholesale prices that reflect the costs of carbon reduction will mute the signals that lead to innovation and will send contradictory signals to consumers, leading to a delay in the behavioral changes needed to achieve the state's goals. History has shown that disconnecting wholesale pricing from retail prices can

lead to poor policy outcomes in the short-term. In the long-term, masking the costs of GHG emission reductions simply means that the goals of AB 32 become that much harder to achieve; meanwhile, program costs increase.

II. GENERAL ISSUES

IEP appreciates this opportunity to comment on the various approaches to allowance allocation policy. Because of the complexity of the subject matter, IEP particularly appreciates the Joint Staff Paper's much-needed analysis and critical thinking on the subject. Without taking a position on the issue of the point of regulation, IEP provides its comments in light of the Joint Recommendation of the Commission and the CEC to the California Air Resources Board ("CARB") that the "deliverer" should be the point of GHG regulation for the electric sector. The "deliverer" includes in-state generation and the owner of imported power when it is first delivered to the electric grid serving California.

While the Joint Staff Paper observes that "selection of a point of regulation does not predetermine the approach to allowance allocation,"[3] severing the allocation of allowances necessary to measure compliance with the requirements of AB 32 from those entities that are actually subject to the regulatory obligation imposed by AB 32 raises a host of questions and concerns. Divorcing access to allowances from the point of regulation inserts a measure of uncertainty and, potentially, peril that could undermine the achievement of the GHG emissions reduction targets "effectively and equitably, at the lowest cost to consumers," as recommended by the Joint Staff Paper.[4]

[3] Joint Staff Paper, p. 1.
[4] Joint Staff Paper, p. 1.

III. PROPOSED CRITERIA FOR EVALUATION OF POLICY OPTIONS

The Joint Staff Paper recommends four criteria for evaluating the various allocation methods:

- Consumer Cost,
- Equity among Customers of Retail Providers,
- Administrative Simplicity, and
- Accommodation of New Entrants.[5]

These four criteria may be necessary when comparing various allocation options. However, they are not sufficient.

AB 32 sets several goals for the implementation of the GHG reduction program that can be used to evaluate various programmatic impacts, including the allowance allocation options. Specifically, AB 32 states the Legislature's intent that the program should be implemented to:

- Minimize costs and maximize benefits for California's economy;
- Improve and modernize California's energy infrastructure;
- Maintain electric system reliability;
- Maximize additional environmental and economic co-benefits for California; and
- Complement the state's efforts to improve air quality.[6]

While the Joint Staff Paper proposes to apply the four broad criteria listed above for evaluation purposes, these four broad criteria do not fully encompass the five elements specified in AB 32. Accordingly, to be successful and sustaining and in conformance with the

[5] Joint Staff Paper, pp. 9-12.
[6] Pub. Resources Code § 38501(h).

intent of AB 32, the GHG program, including the allowance allocation issue, should be evaluated in light of the following additional criteria:

a. ***Grid Reliability*** **[i.e., "maintains electric system reliability"].** Maintaining grid reliability is essential to ensure a sustainable program. Policymaker and public support for a GHG program may wane quickly if grid reliability is compromised. As part of the evaluation of the GHG program from a grid reliability perspective, the Commission should consider the following questions:

i. How do the various allowance options impact generator operations in real-time?

ii. To what extent do generators, as a recommended "point of regulation," have access to allowances to match their operations when directed by the California Independent System Operator ("CAISO") or other third-parties to operate out of dispatch order or in an unexpected and unplanned manner? Similarly, to what extent will generators operating under existing contracts that have no provision for the cost recovery of required allowances have the means to obtain such cost recovery in a timely and cost-effective manner?

b. ***Sustainable GHG Emission Reduction*** **[i.e., "improves and modernizes California's energy infrastructure"].** The purpose of AB 32 is to reduce GHG emissions statewide. That goal implies contributions from various supply-side sectors, including the electric sector, the transportation sector, and the large combustion sector (e.g., cement, natural gas end-use consumers). Attaining this goal requires participation by the demand-side (i.e., end-use consumers) as well. Accordingly, end-use consumers must experience the effects of GHG program implementation (including costs) in as transparent a manner as possible while being provided as many options as practical to minimize any negative effects [e.g. Demand-side Management ("DSM")tools to manage their personal energy use to lower costs]. Shielding consumers from the wholesale costs of compliance within the electric sector through "revenue recycling" will muffle the price signal for technological change and innovation that create options for consumers. This will have the effect of perpetuating consumption patterns that lead to higher-than-desired emission levels for a longer period of time than would otherwise occur. In essence, sheltering consumers from the costs of GHG reduction in the short-term will postpone the necessary transformation of the California economy, delay the introduction of innovative technologies, and result in higher overall costs to consumers.

c. ***Competitive Level Playing Field*** **[i.e., "minimizes cost"; "improves and modernizes", "maximizes additional environmental and economic co-benefits"].** Currently, the generation sector in California is diverse in terms of fuels, technologies, and ownership structures.[7] For the 75 percent of the state's load subject to the jurisdiction of the Commission, a "hybrid market structure" is the adopted model in which utility-owned generation ("UOG") is supposed to compete against independent power producers ("IPPs") to supply the electricity needed to serve load. To serve the remaining 25 percent of the market, the municipal utilities either build their own generation or enter into contracts with IPPs or other utilities. Thus, the generation development arena is characterized not only by disparate technology types but also by distinct ownership types (IPP, investor-owned utilities, and publicly-owned utilities). While California

[7] California's reputation for encouraging clean generation is grounded in the state's history of supporting alternative generation built, owned and operated by independent power producers.

power markets are not fully competitive today, it would be a particularly poor result from a public policy perspective if GHG program implementation undermines achievement of critical policy objectives like attaining a competitive level playing field. If this outcome were to occur, the state would risk a flight of private-sector capital investment (needed for clean technologies) to other jurisdictions and, correspondingly, consumer costs would increase unnecessarily. Accordingly, GHG allowance allocation policy must be evaluated in the context of its impact on fostering a competitive level playing field among ownership types.[8]

IV. THE JOINT STAFF PAPER'S RECOMMENDATION FOR "EQUITY" CRITERIA RAISES CONCERNS

The Joint Staff Paper recommends evaluating the allowance allocation options based, among other factors, on whether the emission reductions are accomplished "equitably" from the perspective of retail consumers.[9] This approach necessarily will result in poor outcomes as it focuses on the impact on the load-serving entities ("LSEs") representing the consumers rather than the impact on the points of regulation (i.e., the "deliverers"). Establishing a criterion for evaluating the various allowance options based on whether or not the approach is "equitable" across retail groups apparently derives from a desire to ensure that LSEs face roughly equivalent cost impacts associated with achieving the AB 32 goals. However, policy choices necessary to make the impacts on LSEs "equitable" may have negative consequences for the attainment of the other AB 32 goals as described below:

a. **Implications of Revenue Recycling.** "Revenue recycling" is presented in the Joint

[8] IEP recognizes that competition among various technology types will occur as the state strives to achieve its GHG emission reduction goals. This is appropriate. This type of competition is distinct from implementing programs that favor one type of "ownership class" versus another.

[9] Joint Staff Paper, p. 2.

Staff Paper as an option to mitigate the retail rate impacts of various allowance allocation policy options. The strategy is to collect revenues at the wholesale level (derived from a specific revenue allocation policy such as an auction) and allocate the revenues so as to equalize the disparate average retail rate impacts faced by individual LSEs. Alternatively, one proposal is to directly allocate allowances to LSEs for sale to electric generators and others. Either approach, however, has the following negative impacts:

i. **Paradoxical Outcomes: Relatively Lower-Emitting Generation Resources Subsidizing Ownership In Relatively Higher-Emitting Generation Resources.** Revenue recycling results in a wealth transfer from relatively low-emitting generation resources to the recipients of power from the relatively high-emitting generation resources. For example, auction revenues are collected from all obligated entities, including low-carbon emitting generation technologies such as geothermal, biomass, and gas-fired generation, and these revenues are transferred or "recycled" to LSEs serving load based on commitments with relatively high-emitting resources (e.g., coal). The greater the proportion of coal-based resources employed to serve load, the greater the proportion of total revenues allocated to the individual LSE in order to make the rate impacts "equitable."[10] Shielding end-use consumers from the full effect of consuming electricity produced by high-emitting resources is equivalent to a subsidy of the high-emitting resources, since the LSEs purchasing from these

[10] This paradoxical effect is even more pronounced if allowance revenues are "recycled" directly to coal plant owners as proposed by SCE at the May 2 workshop.

resources are insulated from the economic effect of their resource choice. If this program were implemented as proposed, California would be in the unenviable position of explaining why relatively low-emitting "clean" generators are subsidizing the continued operation of relatively high-emitting generators.

The Southern California Edison Company ("SCE") allowance allocation proposal, discussed at the April 21 Joint Commission/CEC Workshop, displays the inherent inequities associated with revenue recycling and ought to be rejected. While described as a method of "allocating emissions to entities that suffer economic harm," the SCE proposal simply transfers wealth from one set of market participants (i.e. relatively low-emitting generation) to another market participant (i.e. SCE and other LSEs with coal-based resources). Essentially, SCE proposes to limit the allocation for allowances to two groups: (1) LSEs based on load served and (2) coal generators based on historical emissions. The SCE proposal excludes all other participants in California who may be facing "economic harm" due to the implementation of the AB 32 program. As a result, the SCE proposal represents a tremendous and unwarranted wealth transfer from other market participants to SCE and other LSEs with high-emitting commitments, while exacerbating the competitive harm (and hence economic harm) to other market participants. This narrow approach must be rejected.

ii. Mitigating Retail Rate Impacts Disconnects Wholesale Markets From Retail Markets. Revenue recycling disconnects the market price signals derived from wholesale markets from retail rates, which should be used to stimulate technological innovation and inform retail consumer behavior. As history has proven, disconnecting wholesale prices from retail rates can have disastrous effects. As the wholesale price of energy changes due to the implementation of AB 32, retail consumers would remain insulated from the market price that signals whether to change consumption patterns (e.g., decrease consumption from relatively higher, fossil-based generation such as coal). This is exactly what happened in 2000-01 when retail rates were frozen (i.e., disconnected) in the face of escalating costs of wholesale supply.

b. Obscuring Price Signals Hinders Attainment of GHG Emission Reduction Goals. Obscuring the price signals associated with GHG emission reduction ultimately undermines the goals of AB32. The value of GHG allowances should be transparent and established separately from the value of other electric products, although cost recovery could be achieved through energy markets in the form of a bundled energy price. The Commission will significantly improve the development of low-emitting energy and capacity products, including energy efficiency and renewables, if it achieves this price/cost transparency. In the long run, the effect of disconnecting the wholesale price signals from retail consumer behavior is to exacerbate, not reduce, overall long-term consumer costs.

i. Auctioning Should Establish Transparent Price Signals For GHG Goal Attainment. To the extent that allowances are auctioned, auctions should be conducted by an independent third-party and result in a transparent market-clearing price ("MCP") for allowances. This cost would presumably flow through in energy markets, if in fact the point of regulation is the "deliverer" as recommended by the Commission. Obscuring the cost of GHG emission reduction (i.e., the cost of allowances) will simply undermine efficient markets needed to send the signals for the necessary investment to accomplish the overall GHG emission reduction goals. In this manner, transparency in the MCP of allowances can serve a long-term public purpose from a GHG reduction perspective.

ii. **Mitigation of MCP Effects on Consumers Is Controlled By LSE Procurement Policy.** The Joint Staff Paper notes concerns about having the coast of allowances flow through in the MCP for energy.[11] This phenomenon derives directly from the recommendation that the "deliverer" be the point of regulation. The "generator as point of regulation paradigm" requires that in-state generators acquire allowances to match against their operations. Just as generators must recover their fuel and variable Operations and Maintenance ("O&M") cost to remain viable, so must they recover the cost of allowances purchased in the marketplace and required by regulation. IEP notes, however, that generators have two means to recover the costs of allowances. First, they can recover the cost of allowances as a pass through via power purchase agreements ("PPAs") either bilaterally negotiated or obtained through competitive solicitations. In this case, the MCP will not be affected by the inclusion of the allowance cost. Alternatively, they can recover the cost of allowances as "merchant" generation bidding into energy markets such as those

[11] Joint Staff Paper, p. 10. "Consumer cost consists of two elements: the true social cost of mitigation (reductions from GHG emissions) that is borne by consumers and transfers to wealth from consumers to producers (or deliverers)." Furthermore, the modeling undertaken by E3 at the direction of staff has been structured to highlight this potential effect in a cap and trade system implemented with the deliverer as the point of regulation.

operated by the CAISO. In this case, allowance costs will reasonably be included in bids and thus will affect the MCP. Importantly, the extent to which generators pursue either the first or second option is largely a function of LSE behavior, because LSEs determine how much generation they procure through PPAs and how much they purchase in the short-term markets. Thus, LSEs can control the extent to which consumer's retail rates are affected by carbon values in the real-time MCP for energy (i.e., LSEs control the so-called "windfall profits" associated with the MCP in the E3 analysis).

c. **A Cap and Trade Program Can Be Beneficial IF the Market Is Liquid and Efficient.** IEP generally supports a cap and trade ("CT") program as an important, beneficial means to achieve compliance with CARB's requirements at the least-cost. By extension, consumers benefit when entities such as generators are able to comply with regulations at a lesser cost than would otherwise occur. However, to operate optimally, the CT market must be well-designed, efficient, and "liquid" (characterized by many buyers and sellers) across many sectors.

   i. **A CT Program Is Means to End; Not End Unto Itself.** CO2 regulation of the electric sector is not like SOx or NOx regulation. In reality, beyond some slight efficiency gains that can be achieved through operational modifications and or fuel switching, electric generators have effectively two means to achieve compliance: (a) reduce operations or (b) obtain allowances or offsets. Presently, no commercially available technology exists that can be retrofit onto a generator to reduce GHG emissions. Unlike programs to reduce SOX, NOx, and particulate emissions, the GHG emission reduction program does not present power plants with an economic choice between purchasing allowances or offsets or, alternatively, making capital expenditures for installing hardware solutions that result in emission reductions.

While the CT program can be an important tool for reducing the overall costs of GHG compliance faced by a "point of regulation," if the CT program is not efficient or sufficiently liquid, then problems will inevitably arise**.** For example, if the CT program is not applied uniformly across all the key sectors of the economy, it may not provide the desired benefit in reducing statewide GHG emissions, because the electric generation sector will have to continue to operate to serve load and ensure grid reliability (or else the state will face electrical outages in the name of GHG policy). As the results of the staff-directed E3 modeling show, GHG emission reductions in the electric sector are achieved through load-based programs such an aggressive Renewable Portfolio Standard ("RPS") (33% of total delivered energy by 2020) and energy efficiency ("all cost effective energy efficiency").

ii. If the CT program is limited to only the electric sector, the effect of the cap and trade program[12] will be to increase the cost of generation with no significant effect on GHG emissions in the near term.[13] This is shown clearly in the E3 modeling work presented in the May workshops and in the May 13 versions of E3's presentation. The E3 analysis shows that at the baseline natural gas costs

[12] This statement assumes that allowances are distributed in some manner that freely provides them to every entity that needs them and in sufficient numbers to cover all of a deliverer's GHG emissions.

[13] Over time, higher-emitting resources will be economically disadvantaged and will be replaced by lower-emitting resources, but that transformation will be very slow if the CT program is limited to only the electric sector.

of \$7.85 per MMBtu, GHG allowance costs must reach a level of \$60 per tonne before coal generation imports are uneconomic as compared to gas generation. At higher natural gas costs (such as we see today) allowance costs must rise to \$90 per tonne before coal generation is displaced by cleaner gas generation.[14] Furthermore, the E3 analysis reveals that GHG allowance costs must reach nearly \$120 per tonne to induce incremental investment in renewable generation above the RPS standards. Thus, while the CT program can be an important tool for reducing the overall costs of GHG compliance faced by the State as a whole, if the CT program is limited to narrow sectors its sole effect will be to increase costs with no commensurate reduction in GHG emissions.

iii. **Limiting the CT Market To the Electric Sector Creates Risks.** IEP is concerned that the "multi-sector" CT program envisioned by the Market Advisory Committee ("MAC") Report risks becoming increasingly limited and narrow. The Western Climate Initiative has drafted language for comment that would exclude the transportation sector from GHG reduction efforts. The Commission and the CEC have recommended excluding the natural gas end-use sector. In addition, as concerns over "leakage" of specific California-based industries have grown, industries with significant GHG emission profiles have sought exemption from AB 32 implementation including the CT program. Finally, the concept of revenue recycling has been used to remedy the economic harm expected to be faced by owners of coal facilities or the customers that consume their power. If revenue recycling was to be applied for this purpose,

[14] E3 May 13 Presentation, Slide 23.

coal-based resources would be essentially indifferent to where and how allowances are acquired (assuming they still have to acquire them). The effect of these proposal will be to reduce active participation in the CT program, thereby raising concerns [15] of liquidity and price volatility when too few entities participate.

d. IEP's Support for a Cap and Trade Program Is Conditional. IEP historically has supported CT programs as an economically efficient means to achieve regulatory compliance. This support, however, is conditioned on the following:

- **a.** Fair, equitable and efficiently administration of the CT market;
- **b.** Robust participation by both buyers and sellers to protect against unwarranted and unwanted volatility; and
- **c.** Availability to all generators of the means to acquire allowances and recover the cost of such acquisition in a timely and reasonable manner. This condition would apply to generators operating under existing contracts as well as new assets.

Limiting the CT market to the electric sector and shielding the demand-side from market signals regarding the cost of internalizing the GHG externalities likely will fail as an emission reduction strategy.

[15] A significant number of generators operate today under the terms of existing long-term contracts that never contemplated a GHG allowance obligation. These existing contracts include the QF contracts (primarily with renewable generators and Combined Heat and Power (CHP) assets). In addition, a limited number of existing "tolling" contracts face a similar situation. While new contracts are expected to directly address the cost recovery of any allowances borne by electric generators, for a transitional period pending the expiration of the existing contracts, recovery of allowance costs will remain a significant concern.

V. <u>AUCTIONS, IF EMPLOYED, MUST BE FAIR AND THE REVENUES MUST BE USED TO ACHIEVE LONG-TERM, PERMANENT GHG EMISSIONS REDUCTION</u>

Revenues from the auction of allowances should be used to achieve long-term, permanent GHG emissions reduction. The absence of long-term investment in GHG reduction strategies will simply delay the attainment of the emission goals and potentially risk increasing overall costs to consumers. As noted above, IEP has reservations about proposals to recycle revenues to mitigate rate impacts, because the effect will be to maintain the status quo rather than invest in real carbon-reducing strategies.

a. **Third Party Administration of Allowance Allocations.** The administration of the allowances, including auctioning if that option is chosen, must be conducted by an independent third-party. A suitable third-party entity should be one that has no interest in the electric generation sector, particularly the generation development sector.

b. **Re-investment in Sustainable GHG Emission Reduction (vs. Rate Mitigation).** Revenues from an allowance auction should be used to re-invest in long-term emission reduction strategies. In contradiction to the directives of AB 32, an approach that uses revenues to mitigate rate impacts: (a) delays achievement of GHG emission reduction goals, thereby increasing long-term consumer costs rather than minimizing them while doing little if anything for the California economy; (b) delays investment to improve and modernize the California energy infrastructure; (c) preserves the status quo without maximizing additional environmental and economic co-benefits (e.g., jobs, taxes); and (d) fails to complement the state's efforts to maintain air quality. **In the absence of this type of investment, the GHG program, particularly the CT program, will fail to fulfill its statutory obligations; it will simply become a tremendous revenue generator and the revenues will flow to uses unrelated to GHG emissions**

reduction to the benefit of all consumers.

Allowance Revenues Should Deliver Long-term, Lasting GHG Emissions Reduction. Revenues should be used to re-invest in lowering statewide GHG emissions, including, but not limited to, those in the electric sector. Significant investment in clean, lower-emitting electrical resources; infrastructure to accommodate the electrification of the transportation sector and increased public transit infrastructure; research, development, and demonstration efforts in zero- or low-emitting generation resources, etc. are examples of investments in the long-term infrastructure needed to attain and maintain the GHG emission goals of 2020 and 2050, respectively. Absent this type of critical infrastructure investment, attainment of the 2020 and 2050 goals will not occur.

Respectfully submitted this 2nd day of June, 2008, at San Francisco, California.

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By *_/s/ Steven Kelly_*
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Attachment A
IEP Responses to ALJs' Questions

I. SUMMARY

The summary of IEP's positions and comments is set forth in the document that accompanies this attachment.

II. GENERAL ISSUES

3. (5/13/08 Ruling) For any non-market-based emission reduction measures for electricity discussed in your opening comments, are there any overlap or compatibility issues with the potential electricity sector participation in a cap-and-trade program? Explain.

<u>Treatment of Eligible Renewable Resources</u>. The electricity sector represents only approximately 20% of the total statewide emissions. Overall emission reductions for the electricity sector are highly dependent on successful implementation of the California Renewable Portfolio Standard ("RPS"). IEP recommends that all certified, eligible renewable resources should be exempt from the cap and trade ("CT") program. While eligible renewable resources should report their emissions as established in CARB's recent Mandatory Reporting Regulations, their participation in the CT program is problematic and unnecessary.

The participation of eligible renewable resources is particularly problematic because the Commission-approved RPS Standard Terms and Conditions of RPS contracts require eligible renewable resources to transfer all their environmental attributes to the counter-parties to the RPS contracts (i.e., the load-serving entities ("LSEs")). This requirement effectively makes eligible renewable resources that enter into RPS contracts with California investor-owned utilities ("IOUs") equivalent to "null" power and, hence, subject to acquiring allowances to match the imputed greenhouse gas ("GHG") emissions of null power. Positioning eligible renewable resources to have to purchase GHG allowances is counter-productive and counterintuitive. Accordingly, eligible renewable resources should be exempt from the CT program.

Treatment of End-Use Natural Gas Sector (Excluding Natural Gas Fired Electrical Generation). The Commission should reconsider exempting the natural gas end-use sector. While the bulk of natural gas consumption via the electricity sector is captured by treating in-state natural-gas fired electric generators as the point of regulation, not pursuing the remaining components of the natural gas sector that are cost-effective to implement creates a hole in the implementation of Assembly Bill ("AB") 32. The effect of this omission is to increase the burden on the electricity sector and other sectors included in AB 32 implementation plans.

10. (5/13/08 Ruling) What evaluation criteria should be used in assessing each issue area in these comments (allowance allocation, flexible compliance, CHP, and emission reduction measures and policies)? Explain how your recommendations satisfy any evaluation criteria you propose.

As noted elsewhere, IEP recommends that the Commission should consider the following additional criteria when evaluating policy options:

i. *Grid Reliability* [i.e., "maintains electric system reliability"]. Not undermining grid reliability is essential to ensure a sustainable program. Policymaker and public support for a GHG program may wane quickly if grid reliability is compromised. As part of the evaluation of the GHG program from a grid reliability perspective, the Commission should consider the following questions:

1. *How do the various allowance options impact generator operations in real-time?*
2. *To what extent do generators, as a recommended point of regulation, have access to the allowances that may be necessary to operate in real-time (e.g., when directed by the CAISO out of dispatch order, in an unexpected and unplanned manner)?*
3. *To what extent do generators, such as the QFs operating pursuant to existing fixed price contracts or administratively determined pricing*

methodologies, have an opportunity to recover the full costs of acquiring allowances needed to operate in real-time?

ii. ***Sustainable GHG Emission Reduction*** **[i.e., "improves and modernizes California's energy infrastructure"].** The purpose of AB 32 is to reduce GHG emissions statewide. That goal implies contributions from various supply-side sectors, including the electric sector, the transportation sector, and the large combustion sector (e.g., cement, natural gas end-use consumers). Attaining this goal requires participation by the demand side (i.e., end-use consumers) as well. Accordingly, end-use consumers must not only be made aware of the programmatic goals established by AB 32, but they should also experience the costs for GHG program implementation in as transparent a manner as possible while being provided as many options as practical to minimize those costs (i.e., tools to manage their personal energy use to lower costs). Shielding consumers from the wholesale costs of compliance within the electric sector (e.g., through "revenue recycling") will muffle the price signal for technological innovation that will create options for consumers and will have the effect of perpetuating the consumption patterns that lead to higher-than-desired emission levels for a longer period of time than would otherwise occur. In essence, sheltering consumers from the costs of GHG reduction in the short term will postpone the necessary transformation of the California economy, delay the introduction of innovative technologies, and result in higher overall costs to consumers.

iii. ***Competitive Level Playing Field*** **[i.e., "minimizes cost"; "improves and modernizes", "maximizes additional environmental and economic co-benefits"].** Currently, the generation sector in California is diverse in terms of fuels. technologies, and ownership structures.[16] For the 75 percent of the state's load subject to the jurisdiction of the Commission, a "hybrid market structure" is the adopted model in which utility-owned generation ("UOG") is supposed to compete against independent power producers ("IPPs") to supply the electricity

[16] California's reputation for encouraging clean generation is grounded in the state's history of supporting alternative generation built, owned and operated by independent power producers.

needed to serve load. To serve the remaining 25 percent of the market, the municipal utilities either build their own generation or enter into contracts with IPPs or other utilities. Thus, the generation development arena is characterized not only by disparate technology types but also by distinct ownership-types (IPP, investor-owned utilities, and publicly-owned utilities). While California power markets are not fully competitive today, it would be a particularly poor result from a public policy perspective if GHG program implementation undermines achievement of critical policy objectives like attaining a competitive level playing field. If this outcome were to occur, the state would risk a flight of private-sector capital investment (needed for clean technologies) to other jurisdictions and, correspondingly, consumer costs would increase unnecessarily. Accordingly, GHG allowance allocation policy must be evaluated in the context of its impact on fostering a competitive level playing field among ownership types.[17]

11. (5/13/08 Ruling) Address any interactions among issues that you believe the Commissions should take into account in developing recommendations to ARB.

See response to Question 10.

12. (5/13/08 Ruling) In establishing policies regarding allowance allocation, flexible compliance, CHP, and emission reduction policies, what should California keep in mind regarding the potential transition to regional and/or national cap-and-trade programs in the future? Are there policies or methods that California should avoid or embrace in order to maximize potential compatibility with other cap-and-trade systems?

If a broader regional structure is implemented, then it may well very important to ensure that the individual jurisdictional units within the broader regional program implement, in a uniform and consistent manner, policies regarding allowance allocations, use of revenues, etc. To the extent that allowance allocation schemes are left to individual states (e.g., as currently

[17] IEP recognizes that competitive among various technology types will occur as the state strives to achieve its GHG emission reduction goals. This is appropriate. This type of competition is distinct from implementing programs that favor one type of "ownership class" versus another.

recommended by the Western Climate Initiative), then questions of infringing the Dormant Commerce Clause arise, questions of potential impacts from a "leakage" perspective become more prevalent and critical, etc. Uniform and consistent treatment, particularly regarding allowance allocation, seems to be at the heart of a successful regional structure.

13. (5/13/08 Ruling) For each issue addressed in your comments, do you have any recommendations about the level of detail and specificity regarding the electricity and natural gas sectors that ARB should include in the scoping plan? Is there enough information in the record in this proceeding to support that level of detail and specificity? What additional information and/or analysis may be needed before ARB finalizes its scoping plan? What determinations regarding the electricity and natural gas sectors should ARB defer for further analysis after the scoping plan is issued? Please be as specific as possible about GHG-related policies for the electricity and natural gas sectors that you recommend be resolved this year, and policies that you believe should be deferred for further analysis after the scoping plan is issued.

IEP has no comments on this issue at this time.

1. (5/6/08 Ruling) Please explain in detail your comprehensive proposal for flexible compliance rules for a cap-and-trade program for California as it pertains to the electricity sector. Address each of the cost containment mechanisms you find relevant including those mentioned in this ruling and any others you would propose.

IEP recommends that the points of regulation be afforded up to three years to come into compliance with the GHG regulations. In an allowance-based program, an individual "point of regulation" would have *up to three years* to acquire the requisite allowances to match its GHG emissions in the year for which the obligation occurs. For example, assuming 2012 was the initial year of regulatory compliance, a point of regulation would have up until the end of 2015 to acquire the requisite allowances for the purpose of meeting 2012 compliance obligations; for the second year of the compliance program, i.e., 2013, the regulated entity would have until the end of 2016 to acquire the necessary allowances for the purpose of meeting 2013 compliance obligations.

An entity's compliance obligation would be met through the acquisition of the requisite amount of allowances or offsets necessary to match that entity's emission profile for a reporting year. Offsets, as further discussed below, must be (a) additional and (2) verifiable (as determined by the appropriate regulatory body).

The appropriate regulatory body should retain an "emergency reserve" of allowances to apply as needed to ensure grid reliability in the electricity sector.

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

<u>The three-year rolling compliance period</u> will ensure that California will attain its overall GHG goals in a reasonable timeframe at the least cost. The alternative would be to establish a "hard rule" fixing the compliance period at a date certain, in which case the overall program unnecessarily risks increasing costs or, alternatively, threatening grid reliability.

<u>Offsets</u> by definition would be additional and verifiable. An appropriate regulatory body would have the responsibility to approve offsets prior to entering them into the system to be used for compliance. From a GHG emissions reduction perspective, an offset should match the emissions reduction value associated with an allowance (i.e., "a ton is a ton").

Because the purpose of the GHG program is to mitigate *global* climate change by reducing *global* emissions, programmatic goals are not undermined by allowing offsets to be used for compliance purposes. Accordingly, the use of offsets will be consistent with maintaining the environmental integrity of the overall system at lowest cost.

The only administrative complexities associated with the use of offsets are (a) establishing the standards for additionality, (b) creating protocols for ensuring verification, and (c) determining how best to link to other reporting systems to ensure against double-counting.

By adopting equivalent protocols from other jurisdictions, California will be (a) ensuring maximum linkage with other systems and (b) reducing the overall administrative complexity.

Regarding the concept of a Reserve Fund, IEP envisions the Reserve Fund as serving a "damage control" function. The Reserve Fund would provide a means to access an "emergency reserve" of allowances. The purpose of the Reserve Fund (much like the Federal Reserve for the banking system) is to serve as an institution to (a) ensure adequate liquidity in the trading system, and (b) provide a market monitoring function to protect against unreasonable volatility or market manipulation. The Reserve Fund would have the access and authority to buy and sell allowances to stabilize the market as needed.

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

The cap and trade system is premised on a market-based approach to attain program compliance. This, of necessity, requires (a) a liquid market (i.e., many buyers and sellers), (b) transparency in determining the market price of exchange-traded or auctioned allowances, and (c) effective market monitoring to protect against market manipulation. The aforementioned flexible compliance tools assist in achieving this outcome. First, the three-year rolling compliance period provides the points of regulation with a compliance tool to avoid relatively short-term periods of relatively high-priced allowances, thereby potentially lowering overall costs and fostering price stability. The three-year rolling compliance period also provides a means for generating units operating on the instructions of the CAISO in real-time to acquire necessary allowances to match their emissions output that is effectively beyond their control (assuming a reasonable means to recover these costs). Second, the use of offsets (preconditioned on the proper determination as to their additionality) provides a means to (a) make the market more liquid, thereby potentially flattening the volatility of the allowance market, and (b) lower the overall cost of GHG program compliance under the assumption that offsets would not be employed unless they were better than the alternative, i.e., the acquisition of state-sanctioned and released allowances. Third, implementation of the emergency reserve concept, through a reputable third-party institution or governmental entity, also will serve to improve the liquidity in the market and protect against unreasonable and unhelpful volatility in the CT market.

2. (5/6/08 Ruling) With respect to flexible compliance mechanisms, what should California keep in mind in designing its system when considering the potential transition to regional and/or national cap-and-trade programs in the future? Are there mechanisms that California should avoid or embrace in order to maximize potential compatibility with other cap-and-trade systems?

First, while IEP supports a broader regional or federal program, California should not assume that a broader federal program will be in place prior to 2012.

Second, California can consider overall program design as a transitional step until a federal program is in place. In this regard, IEP urges the Commission to consider the impact of its policy options and choices in the context of ensuring overall grid reliability.

Third, California can and should now adopt a policy endorsing offsets while deferring to later the specifics of how to measure additionality and verification. This will send important signals to the marketplace that can affect critical investment decisions in innovative technologies.

3. (5/6/08 Ruling) What evaluation criteria should be used in assessing flexible compliance options?

IEP believes "grid reliability" is critical, as noted elsewhere, i.e., policy options should not undermine grid reliability and, if possible, they should strengthen it. Not undermining grid reliability is essential to ensure a sustainable program. Policymaker and public support for a GHG program may wane quickly if grid reliability is compromised. As part of the evaluation of the GHG program from a grid reliability perspective, the Commission should consider the following questions:

a. *How do the various allowance options impact generator operations in real-time?*

b. *To what extent do generators, the recommended "point of regulation," have access to the allowances that may be necessary to operate in real time (e.g., when directed by the CAISO out of dispatch order, in an unexpected and unplanned manner)?*

c. *To what extent do generators have an opportunity to recover the full costs of acquiring allowances needed to operate in real time, particularly in light of the "must-run" obligations imposed by the CAISO to ensure grid reliability?*

III. ALLOWANCE ALLOCATION

A. Detailed Proposal

1. (4/16/08 Ruling) Please explain in detail your proposal for how GHG emission allowances should be allocated in the electricity sector.

Currently, the Commission is recommending that the point of regulation be the "deliverer" of energy onto the California electrical grid. This includes in-state electrical generation and the owners of imported power when it is first delivered onto the California electrical grid.

The "point of regulation" should be the primary recipients of any allowance allocation scheme. Disconnecting the direct availability of allowances from those entities responsible for compliance likely will (a) result in unintended consequences (e.g., for the electric sector the potential for undermining grid reliability if generators are unable to access allowances needed to operate in a timely manner), and (b) increase costs. To the extent that entities not identified as a "point of regulation" desire to buy or sell allowances or offsets, a *secondary* market will emerge to accommodate such transactions. A secondary market in allowances and offsets will foster needed liquidity in the market, improve price transparency, and facilitate program compliance. However, as regards the *primary* means for allocating allowances (i.e. the initial means of distribution from regulators to the marketplace), access to allowances, whether auctioned or administratively allocated, should be limited to the "points of regulation" who need the allowances to achieve regulatory compliance.

10. (4/16/08 Ruling) Describe in detail the method you prefer for returning auction revenues to benefit electricity consumers in California. In addition to your recommendation, comment on the pros and cons of each method listed above, especially regarding the benefit to electricity consumers, impact on GHG emissions, and impact on consumption of electricity by consumers.

There is NO point in creating a CT market or any other regulatory mechanism unless it actually results in lowering GHG emissions. IEP favors reinvesting auction revenues in actions that will result in long-term, sustainable reductions in GHG emission levels. We are not convinced that returning auction revenues to mitigate rate impacts on consumers will have any long-term sustaining effects. As discussed above in response to Question 3, to avoid the approval requirements associated with a "tax," CARB and the Commission should avoid the appearance that auction revenues are collected for unrelated revenue purposes and ensure that the revenues collected through the auction are used for purposes reasonably related to the goals of AB 32.

Within the context of "returning auction revenues to benefit electricity consumers in California," investing in long-term sustainable reductions in GHG emission levels will produce the greatest benefit to electricity consumers. Accordingly, within the electric sector, auction revenues should be re-invested in zero- or low-emitting generation resources necessary to maintain grid reliability and achieve the desired emission reduction goals. These investments will include energy efficiency, renewables, clean coal, and relatively low-emitting generation resources to maintain grid reliability. Investments outside the electric sector would include investments in clean transportation infrastructure, including infrastructure to accommodate the electrification of the transportation fleet, mass transit, etc.

By reinvesting auction revenues in the infrastructure necessary to achieve AB 32 compliance in a timely and sustaining manner, the Commission will be directly linking AB 32 program implementation and its method of allowance allocation in a manner designed to reduce sector-wide emissions as quickly as financially feasible, rather than designing a program that undermines the types of behavioral changes needed to ensure long-lasting, sustainable effects.

In addition, reinvesting auction revenues in the infrastructure necessary to achieve AB 32 compliance in a timely and sustaining manner appears to foster a purpose more consistent with the requirement that regulatory fees (as distinct from taxes) must "not exceed the reasonable cost of providing services necessary to the activity for which the fee is charged and which are not levied for unrelated revenue purposes."[18]

B. Response to Staff Paper on Allowance Allocation Options and Other Allocation Recommendations

8. (4/16/08 Ruling) The staff paper describes an option that would allocate emission allowances directly to retail providers. If you believe that such an approach warrants consideration, please describe in detail how such an approach would work, and its potential advantages or disadvantages relative to other options described in the staff paper. Address any legal issues related to such an approach, as described in Questions 2 – 4 above.

IEP opposes regulatory authorities allocating emission allowances to any entity not treated as a "point of regulation". Only under a load-based approach does it make policy sense to allocate emission allowances from the regulatory authorities directly to retail providers.

Allocating allowances directly to retail providers under a "deliverer" approach will disconnect the points of regulation from the tools for achieving their regulatory obligation. As a result, access to needed allowances by electric generators may be conditioned by the willingness

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[18] *Sinclair Paint Co. v. State Bd. of Equalization*, 15 Cal.4th at 876, quoting *Pennell v. City of San Jose* (1986) 42 Cal.3d 365, 375.

of other market participants (e.g., LSEs, hedge funds, etc.) to sell allowances, with nothing to ensure that electrical generators would have access to allowances at a reasonable price and in a timely manner.

Presently, the electric sector in California is characterized by (a) competition and (b) a hybrid-market structure. As a result, many retail providers, including the investor-owned utilities and the municipal utilities, retain significant generation interests (operation and development) in addition to their interests in serving retail load. Thus, allocating allowances directly to retail providers may provide such entities with an unwarranted control over the availability of allowances needed by independent electric generators with whom they compete.

The effect of allocating allowances directly to retail providers would be to unnecessarily increase costs to consumers; tilt the competitive level playing field between utilities (i.e., retail providers) and IPPs to the detriment of consumers; potentially require IPP generation to subsidize UOG; and undermine private sector investment in California generation.

9. (4/16/08 Ruling) Please address the effect that each of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your own or other parties' opening comments, would have on economic efficiency in the economy, and the economic incentives that each option would create for market participants.

10. (4/16/08 Ruling) Describe in detail the method you prefer for returning auction revenues to benefit electricity consumers in California. In addition to your recommendation, comment on the pros and cons of each method listed above, especially regarding the benefit to electricity consumers, impact on GHG emissions, and impact on consumption of electricity by consumers.

There is NO point in creating a CT market or any other regulatory mechanism unless it actually results in lowering GHG emissions. IEP favors reinvesting auction revenues in actions that will result in long-term, sustainable reductions in GHG emission levels. We are not convinced that returning auction revenues to mitigate rate impacts on consumers will have any long-term sustaining effects. As discussed above in response to Question 3, to avoid the approval requirements associated with a "tax," CARB and the Commission should avoid the appearance that auction revenues are collected for unrelated revenue purposes and ensure that the revenues collected through the auction are used for purposes reasonably related to the goals of AB 32.

Within the context of "returning auction revenues to benefit electricity consumers in California," investing in long-term sustainable reductions in GHG emission levels will produce the greatest benefit to electricity consumers. Accordingly, within the electric sector, auction revenues should be re-invested in zero- or low-emitting generation resources necessary to maintain grid reliability and achieve the desired emission reduction goals. These investments will include energy efficiency, renewables, clean coal, and relatively low-emitting generation resources to maintain grid reliability. Investments outside the electric sector would include investments in clean transportation infrastructure, including infrastructure to accommodate the electrification of the transportation fleet, mass transit, etc.

By reinvesting auction revenues in the infrastructure necessary to achieve AB 32 compliance in a timely and sustaining manner, the Commission will be directly linking AB 32 program implementation and its method of allowance allocation in a manner designed to reduce sector-wide emissions as quickly as financially feasible, rather than designing a program that undermines the types of behavioral changes needed to ensure long-lasting, sustainable effects.

In addition, reinvesting auction revenues in the infrastructure necessary to achieve AB 32 compliance in a timely and sustaining manner appears to foster a purpose more consistent with the requirement that regulatory fees (as distinct from taxes) must "not exceed the reasonable cost of providing services necessary to the activity for which the fee is charged and which are not levied for unrelated revenue purposes."[19]

11. (4/16/08 Ruling) If auction revenues are used to augment investments in energy efficiency and renewable power, how much of the auction proceeds should be dedicated to this purpose?

From a statewide perspective and assuming a multi-sector cap and trade program, electricity represents 20 percent of the statewide GHG emissions. Electrification of the transportation sector will have the effect of increasing electrical demand, all things being equal. Thus, the electric sector revenue allocation should be relatively larger than the relative impact of the sector on total GHG emissions. Accordingly, at least 30 percent of the total auction revenues should be allocated to the electric sector, assuming a multi-sector approach.

Regarding the allocation of the revenues dedicated to the electric sector, for the initial five years of program implementation, 50 percent of the auction revenues should be directed to renewable investment; 30 percent should be directed toward clean or low-emitting alternative resources (e.g., clean coal, low-emitting natural gas); and 20 percent of the auction revenues should be directed toward energy efficiency not otherwise covered by building and appliance standards and similar existing requirements. The 50 percent of auction revenues directed to renewable investment should be used to cover the costs of long-term renewable infrastructure investment (e.g. PPAs) derived through competitive procurement mechanisms necessary to ensure a 33 percent renewable penetration established as policy by the Climate Action Team. After the initial five years, the allocation of allowance revenues should be re-evaluated.

To ensure that the auction revenues are applied to achieve these outcomes, regulators must ensure that the auction revenues are "earmarked" for infrastructure investment to reduce

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[19] *Sinclair Paint Co. v. State Bd. of Equalization*, 15 Cal.4th at 876, quoting *Pennell v. City of San Jose* (1986) 42 Cal.3d 365, 375.

GHG emissions, particularly investment in renewables and energy efficiency. If the utilities serve as the primary means to achieve the GHG emission reduction objectives, due to their role in implementing the RPS and EE programs, then the auction revenues must be set aside in a special account targeted for infrastructure investment, rather than commingled with other utility revenue streams.

12. (4/16/08 Ruling) If auction revenues are used to maintain affordable rates, should the revenues be used to lower retail providers' overall revenue requirements, returned to electricity consumers directly through a refund, used to provide targeted rate relief to low-income consumers, or used in some other manner? Describe your preferred option in detail. In addition to your recommendation, comment on the pros and cons of each method identified for maintaining reasonable rates.

IEP does not believe that auction revenues should be used to mitigate the retail rate impacts of the policy choices made by regulators.[20] Mitigating retail rate impacts has the following consequences:

- It muffles the signal that stimulates technological innovation that can provide an enduring reduction in consumers' GHG emissions and a stable basis for reducing the cost effects on consumers of the GHG emission reduction program.
- It disconnects retail prices and consumer behavior from wholesale costs, which is poor policy. Rate impact mitigation hinders GHG emission reduction, because consumer behavior is shielded from the effects of policy choices that are intended to change behavior;
- It results in increasing long-term consumer costs to achieve AB 32 mandates to the extent that consumer behavior and policy options remain disconnected; and;
- Appears inconsistent with the requirement that regulatory fees (as distinct from taxes) must "not exceed the reasonable cost of providing services necessary to the activity for

[20] The Commission may wish to consider expanding its low-income programs in support of its low-carbon emission goals while stabilizing rates. This would result, for example, in subsidizing energy efficient refrigerators for low-income customers.

which the fee is charged and which are not levied for unrelated revenue purposes."[21]

13. (4/16/08 Ruling) If you prefer a combination of methods for returning auction revenues, describe your preferred combination in detail.

See response to Question 12.

C. Legal Issues

2. (4/16/08 Ruling) Does any of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your opening comments, raise concerns under the Dormant Commerce Clause? If so, please explain why that allocation option(s) may violate the Commerce Clause, including citations to specific relevant legal authorities. Also, explain if and, if so, how the allocation option(s) could be modified to avoid the Commerce Clause problem.

The allowance allocation options do not run afoul of the Commerce Clause if they further a legitimate local (state) purpose (particularly health and safety regulation); if they appear neutral and do not unduly discriminate against out-of-state suppliers or in favor of California suppliers; and if they do not unreasonably burden interstate commerce.[22] The GHG reductions that are the goal of AB 32 are related to the state's health and safety authority, which is a legitimate state purpose, and the proposed allowance allocation mechanisms appear to be closely related to the achievement of those goals. Under the Commerce Clause, the GHG regulations, including the allocation of allowances, must not create an unreasonable burden on interstate commerce. Because all U.S. electricity outside of ERCOT is deemed to be in interstate commerce, any regulation affecting the transmission of electricity must be carefully evaluated for its effect on interstate commerce. All of the allowance allocation options have a potential to create Commerce Clause issues if they unduly discriminate against out-of-state suppliers and in favor of California suppliers or if they unreasonably burden interstate commerce. For example, an

[21] *Sinclair Paint Co. v. State Bd. of Equalization*, 15 Cal.4th at 876, quoting *Pennell v. City of San Jose* (1986) 42 Cal.3d 365, 375.
[22] See *Pike v. Bruce Church* (1970) 397 U.S. 137, 142.

emission-based allocation may not award allowances only to California generators if that allocation makes it burdensome for out-of-state generators to participate in the California market (or if it creates a burden for California generators to participate in other states' markets). Similarly, if participation in the allowance auction is limited in a way that creates a burden on out-of-state suppliers who have a reasonable ability to provide power to California, the Commerce Clause might again be implicated.

The "deliverer" approach to the point of regulation puts in-state generators and imported power on an equal basis for regulatory purposes. To avoid Commerce Clause problems, the allocation of allowances should be designed to provide a similar opportunity for in-state generation and imported power to participate in the California market and should be carefully evaluated to ensure that it does not place an unreasonable burden on interstate commerce.

3. (4/16/08 Ruling) Does any of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your opening comments, raise legal concerns about whether they involve the levying of a tax and, therefore, would require approval by a two-thirds vote of the Legislature? If so, please explain why that allocation option(s) is taxation, including citations to specific relevant legal authorities. Also, explain if and, if so, how, the allocation option(s) could be modified to avoid such legal concerns.

Emission-based allocation proposals provide allowances to deliverers or other emitting entities based on historical emission levels. The "charges" imposed by this allocation method fall on deliverers or other emitting entities that emit GHG in quantities greater than their historical levels (or reduced allocation, as the level of allowances is reduced). These charges lack the compulsory nature of a tax, and entities are not forced to purchase allowances (*i.e.,* they may operate up to the level of their allowances without incurring extra costs for GHG compliance). IEP concludes that an emission-based allocation is not a tax that raises the issues identified in this question.

Auction-based allocation proposals, by contrast, result in revenues and thus bear more of the characteristics of a tax or fee. Auction-based allocation proposals require deliverers or other emitting entities to incur costs to be able to operate at historical levels (using historical methods of production) and to do business in a certain way. Auctions also require some governmental entity to decide what to do with the revenues collected from this auction. Thus, auction-based proposals raise the question whether legal restrictions on taxation are implicated.

The tax issues related to the allocation proposals arise from provisions added to the California Constitution in Proposition 13. In addition to its better-known restrictions on property tax increases, Proposition 13 added the requirement that any tax changes enacted for the purpose of increasing revenues must be approved by a two-thirds vote in both houses of the Legislature.[23] Special taxes imposed by cities, counties, and special districts must be approved by two-thirds of the eligible voters.[24]

On the other hand, fees may be imposed without the approval requirements of Proposition 13. For example, Government Code section 50076 excludes from the definition of "special tax" under Article XIIIA, section 4 "any fee which does not exceed the reasonable cost of providing the service or regulatory activity for which the fee is charged and which is not levied for general revenue purposes." This distinction leads to the question whether an auction approach to allocation is a tax or a fee.

The California Supreme Court has examined this issue in the context of a charge that the Department of Health Services levied on manufacturers of house paint, pursuant to legislation designed to reduce or eliminate the incidence of lead poisoning in children.[25] The Court noted that the line between taxes and fees was blurry, but generally speaking "taxes are imposed for

[23] Cal. Const. art. XIIA, § 3.
[24] Cal. Const. art. XIIA, §4.
[25] *Sinclair Paint Co. v. State Bd. of Equalization* (1997) 15 Cal.4th 866.

revenue purposes, rather than in return for a specific benefit conferred or privilege granted," and that taxes are usually compulsory (although some fees may also be compulsory).[26] Fees, which do not trigger the constitutional approval requirements, can be divided into three categories: (1) *special assessments* on property or similar business charges, based on the value of the benefits conferred on the property or business; (2) *development fees,* such as building permits, exacted in return for permits or other governmental privileges, provided that the amount of the fee is reasonably related to the probable cost to the community and the benefit to the developer; and (3) *regulatory fees* imposed under the government's police powers, rather than the taxing power.[27] Regulatory fees are not taxes if the fees "do not exceed the reasonable cost of providing services necessary to the activity for which the fee is charged and which are not levied for unrelated revenue purposes."[28]

In the case involving the fees imposed on paint manufacturers, the Court concluded that the fees were regulatory fees, not taxes, and were not subject to the approval requirements of Proposition 13.

The authority of CARB to impose fees in the form of auction revenues has two possible statutory sources in AB 32. First, the Legislature authorized CARB to adopt a "schedule of fees to be paid by the sources of greenhouse gas emissions." The revenues from these fees are deposited in the Air Pollution Control Fund and can be appropriated by the Legislature to carry out the goals of AB 32.[29] The auction-based allocation proposal does not appear to fit this framework, since the funds collected are not necessarily set by a schedule to be paid by sources

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[26] *Id.*, 15 Cal.4th at 874.
[27] *Id.*, 15 Cal.4th at 874-875.
[28] *Id.*, 15 Cal.4th at 876, quoting *Pennell v. City of San Jose* (1986) 42 Cal.3d 365, 375.
[29] Pub. Res. Code § 38597.

of greenhouse gas emissions.

The second potential source of CARB's authority is in its authorization to use "market-based mechanisms" to comply with AB 32.[30] If CARB relies on this authority as the basis for its pursuit of an auction-based allocation, the question still arises whether the auction-related charges are fees or taxes. In most respects, auction-based charges have the characteristics of "development fees," which the Supreme Court has ruled are not taxes that trigger Proposition 13's approval requirements. Development fees are charges "exacted in return for permits or other governmental privileges," and are not taxes "provided that the amount of the fee is reasonably related to the probable cost to the community and the benefit to the developer." In the GHG context, auction-based charges result from the desire of *some* entities to emit greenhouse gases, and could be evaluated in terms of the probable cost to the community, *i.e.,* the people and economy of California, and the benefit to the emitter.

Thus, if CARB's authority to pursue market-based mechanisms is broad enough to include the implementation of an auction for allowances, then it should not be too difficult to justify the charges as developer fees that are (1) exacted in return for governmental privileges, *i.e.,* GHG allowances, and (2) reasonably related to the cost to the community and the benefit to the developer. CARB should avoid any suggestion that the proceeds from the auction will be used to increase the state's revenues (which may be difficult in the state's current budget situation) and to devote the revenues to purposes that are reasonably related to the goals of AB 32.

4. (4/16/08 Ruling) Does any of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your opening comments, raise any other legal concerns? If so, please explain in full with citations to specific relevant legal authorities. Also, explain if and, if so, how, the allocation option(s) could be codified to

[30] Pub. Res. Code § 38570.

avoid such legal concerns.

As IEP has emphasized in its comments, California generators are obligated under the CAISO's FERC-approved tariffs to operate if called on by the CAISO under a variety of circumstances. If the allocation of allowances does not accommodate the unpredictable operation of generators subject to the CAISO's directions, generators could find themselves in the uncomfortable position of having to choose between violating federal law (the CAISO's tariff) by not operating when directed by the CAISO and violating California law by operating without the necessary GHG emission allowances. Because of the high priority given to reliability, a generator faced with this choice would in most instances choose to comply with the CAISO's order. To avoid this dilemma, IEP in these comments suggests several mechanisms that will allow generators to comply with both the FERC tariff and California GHG emission reduction requirements.

5. (4/16/08 Ruling) For reply comments: Do any of the allowance allocation options discussed in other parties' opening comments raise concerns under the Dormant Commerce Clause? If so, please explain why that option(s) may violate the Commerce Clause, including citations to specific relevant legal authorities. Also, explain if and, if so, how the allocation option(s) could be modified to avoid the Commerce Clause problem.

[For Reply Comments]

6. (4/16/08 Ruling) For reply comments: Do any of the options discussed in other parties' opening comments raise legal concerns about whether they involve the levying of a tax and, therefore, would require approval by a two-thirds vote of the Legislature? If so, please explain why that allocation option(s) is taxation, including citations to specific relevant legal authorities. Also, explain if and, if so, how, the allocation option(s) could be modified to avoid such legal concerns.

[For Reply Comments]

7. (4/16/08 Ruling) For reply comments: Do any of the allowance allocation options discussed in other parties' opening comments raise any other legal concerns? If so, please explain in full with citations to specific relevant legal authorities. Also, explain if and, if so, how the allocation option could be modified to avoid such legal concerns.

[For Reply Comments]

IV. FLEXIBLE COMPLIANCE

A. Detailed Proposal

1. (5/6/08 Ruling) Please explain in detail your comprehensive proposal for flexible compliance rules for a cap-and-trade program for California as it pertains to the electricity sector. Address each of the cost containment mechanisms you find relevant including those mentioned in this ruling and any others you would propose.

IEP recommends that the points of regulation be afforded up to three years to come into compliance with the GHG regulations. In an allowance-based program, an individual "point of regulation" would have *up to three years* to acquire the requisite allowances to match its GHG emissions in the year for which the obligation occurs. For example, assuming 2012 was the initial year of regulatory compliance, a point of regulation would have up until the end of 2015 to acquire the requisite allowances for the purpose of meeting 2012 compliance obligations; for the second year of the compliance program, i.e., 2013, the regulated entity would have until the end of 2016 to acquire the necessary allowances for the purpose of meeting 2013 compliance obligations.

An entity's compliance obligation would be met through the acquisition of the requisite amount of allowances or offsets necessary to match that entity's emission profile for a reporting year. Offsets, as further discussed below, must be (a) additional and (2) verifiable (as determined by the appropriate regulatory body).

The appropriate regulatory body should retain an "emergency reserve" of allowances to apply as needed to ensure grid reliability in the electricity sector.

B. Scope of Market and Related Issues

1. (5/6/08 Ruling)

IEP's responses to parts (a) and (b) of Question 1 are set forth in section II, above.

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

The electricity market is unique in that (a) electricity cannot be efficiently stored physically to any significant extent, and (b) most generators do not have 100 percent control over their operations in all hours. Electric generators face a number of tariff-based and contract-based obligations to be available to operate at the direction of third parties. Third parties include the CAISO seeking to meet grid reliability obligations and responsibilities dynamically in real-time; and LSEs seeking to match the forecasted load (monthly, daily, hourly) that changes due to climate fluctuations, changes in end-use consumption, etc. As a result, electric generators, which have been recommended to be the point of regulation do not maintain full control the amount of carbon they emit.

Given the lack of full control over their operations, electric generators have two options if they serve as the point of regulation. First, they can reduce operations to match the allowances they have in their control at that time. As noted elsewhere, this outcome can have negative impacts on overall grid reliability. Secondly, they can acquire allowances to match real operations. To do this, they need a viable means to acquire such allowances at least cost AND they must have a reasonable means to recover these operational costs much like they need to recover the cost of fuel. The absence of a reasonable means to recover the cost of GHG compliance effectively eliminates the second option. Hence, (a) the need for overall grid reliability to be included in the criteria for evaluating options; and (b) the need for a liquid and efficient carbon allowance trading scheme coupled with the flexible compliance tools mentioned above.

Another unique circumstance in the electric sector is presence of a significant number of electric generation facilities operating under Commission-approved contracts that provide no means to recover the additional cost of allowances. These include QFs, including many renewable electric generators and cogenerators (Combined Heat and Power), i.e. the types of facilities sought by regulators, operating under fixed price contracts or pursuant to administratively determined payment methodologies. In addition, a limited number of electric generators may be operating under existing Tolling Agreements. While this is a transitional problem, the reality is that many electric generators may not have a reasonable means to recover the cost of allowance acquisition under the terms and conditions of their existing contracts. Either a reasonable means needs to be created to ensure GHG allowance cost recovery or these generation units should be deemed compliant from a GHG regulatory perspective while they continue to operate under these transitional contract structures.

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

To ensure liquidity in the market, the CT market must be multi-sector. In California today, the electric power sector contributes an estimated 16 percent of the overall statewide CO2 emissions.[31] A CT program that excludes the transportation sector, the natural gas sector, and large point source emitters (e.g., cement) will restrict the liquidity of the market, heighten the potential for volatility, and ultimately risk overall grid reliability.

A multi-sector market-based approach, coupled with the ability to bring offsets to the market as a means for compliance, will ensure that (a) the market remains as liquid as possible,

[31] Economic Assessment for Climate Action in California, "Overview of the BEAR Model," Roland-Holst, 19 May 2008, [Presentation to Stakeholders, p. 13].

and (b) regulatory compliance is achieved at the lowest possible cost. Furthermore, the absence of a truly multi-sector approach will essentially neutralize the value of the flexible compliance tools that IEP believes are central to stability in the GHG emissions reduction program.

The state's ability to achieving these outcomes, however, is undermined the extent to which obligated entities' (i.e. the points of regulation) access to the necessary allowances is restricted. For example, some parties have advocated that allowances be allocated to non-regulated entities for sale to obligated entities. This allocation proposal creates a disconnect between the points of regulation and the permits needed to operate and, in doing so, raises a host of problematic policy outcomes.

- First, this proposal raises concerns regarding overall grid reliability.
- Second, it raises concerns regarding unnecessarily imposing a third-party between obligated entities and their obligations.
- Third, it raises concerns regarding the potential manipulation of allowances (e.g., hoarding) to affect competitive market outcomes favorable to the LSEs' generation development interests.

In the context of the electric sector only, IEP also is troubled by proposals that create an unfair competitive advantage or undermine the liquidity in the CT market. These include the following:

- Proposals to exempt relatively high emitters such as coal-based electric generators from the CT program; or, alternatively,
- Proposals such as "revenue recycling" that would have the effect of exempting relatively high-emitting resources owned by LSEs in California by making them financially indifferent to the GHG limitations.

Revenue recycling, as proposed, would simply have the effect of making the relatively high emitters indifferent to whether the market is liquid or not; it would make them indifferent to the effects of volatility in the market clearing price ("MCP"); and it would result in the ironic situation in which California's GHG emission program would be characterized by the relatively low-emitting resources subsidizing the relatively high-emitting resources. This cannot be the outcome that California policymakers and regulators would like to achieve or defend.

4. (5/6/08 Ruling) To what extent should the recommendations to the ARB for flexible compliance in the electricity sector depend on the ultimate scope of the multi-sector cap-and-trade program and other market design issues such as allocation methodology and sector emission reduction obligations? Can the Commissions make meaningful recommendations on flexibility of market operations when the market itself has not yet been designed? Why or why not?

The Commission can and should make recommendations regarding flexible compliance, because the recommendations will help shape the remainder of the discussion. For example, if offsets are not included in overall design, then a single-sector design may be a disaster, as noted elsewhere.

Irrespective of the "point of regulation" or the specific design features of a CT program, flexible compliance tools provide additional value and should be integrated into the overall design recommendations. Further clarity on outstanding issues will not affect this conclusion, and thus there is no reason to await that clarity.

5. (5/6/08 Ruling) Should the market for GHG emission allowances and/or offsets be limited to entities with compliance obligations, or should other entities such as financial institutions, hedge funds, or private citizens are allowed to participate in the buying and selling of allowances and/or offsets? If non-obligated entities are allowed to participate in the market, should the trading rules differ for them? If so, how?

The allocation of allowances or auctioning of the allowances should be limited initially to the "points of regulation." This limitation will ensure that the "points of regulation" will have meaningful, fair, and comparable access to the allowances needed to attain regulatory compliance. To sever this relationship would be poor public policy.

The Commission should assume that a secondary market in the trading of allowances will emerge. A secondary market will prove beneficial in terms of supporting overall market liquidity, efficiency, etc. Furthermore, the secondary market should be made available to all market participants, including financial institutions, hedge funds, or private citizens. It is through this means that market participants, including those not designated as a "point of regulation," will buy, sell or exchange allowances in a mutually beneficial manner.

C. Price Triggers and Other Safety Valves

6. (5/6/08 Ruling) Should California incorporate price triggers or other safety valves in a cap-and-trade system? Why or why not? Would price triggers or other safety valves affect environmental integrity and/or the ability to link with other systems? Address options including State market intervention to sell or purchase GHG emission allowances to drive allowance prices down or up; a circuit breaker or accelerator which either slows down or speeds up reductions in the emission cap until allowance prices respond; and increasing or decreasing offset limits to increase or decrease liquidity to affect prices. Address how these various strategies would be utilized in conjunction with other flexible compliance mechanisms.

As noted elsewhere, grid reliability is a critical matter that has not been fully considered to date. Clearly, to the extent generators are the "points of regulation," then the maintenance of grid reliability will be a function of allowance availability, cost, and overall market liquidity. As a result, IEP has recommended integration of various flexible compliance mechanisms including utilization of a "reserve fund" mechanism (akin to the Federal Reserve System in banking). To be effective, the institution responsible for acting as the reserve fund would have the means and authority to purchase and sell allowances to maintain overall integrity of the market-based system, including a measure of price stability. As a complement to the other flexible compliance tools advocated by IEP, this reserve fund mechanism would provide a means to ensure that the costs of overall program compliance stay within a range deemed acceptable by the body politic.

7. (5/6/08 Ruling) Should California create an independent oversight board for the GHG market? If so, what should its role be? Should it intervene in the market to manage the price of carbon? If such an oversight board were created, how would that affect your recommendations, e.g., would the oversight board obviate the need to include additional cost containment mechanisms and price-triggered safety valves in the market design?

See IEP's response to Question 6.

D. Linkage

8. (5/6/08 Ruling) Should California accept all tradable units, [i.e., GHG emission allowances and offsets, from other carbon trading programs]? Such tradable units could include, e.g., certified Emission Reductions, Clean Development Mechanism (CDM) credits, and/or Joint Implementation credits.

California should accept all tradable units from "partner" entities. Partner entities may include individual cities, states, nations, or regions. However, to ensure integrity in the market-based trading paradigm, "partners" will by definition be required to (a) agree to a measure of reciprocity and (b) ensure that the tradable units are comparable to the units employed in the California context.

9. (5/6/08 Ruling) If so, what effects could such linkage have on allowance prices and other compliance costs of California obligated entities? Under what conditions could linkage increase or decrease compliance costs of California obligated entities? To what extent would linkage subject the California system to market rules of the other systems? What analysis is needed to ensure that other systems have adequate stringency, monitoring, compliance, and enforcement provisions to warrant linkage? What types of verification or registration should be required?

GHG emission reduction is a global problem that requires a global response and solution. Actors beyond U.S. borders will have significant impact on California-specific problems (e.g., rising sea levels will affect California's coastal areas). These actors must be induced into the system in order to have a global impact. Linking to other comparable systems should increase the incentives for these global actors to reduce GHG emissions on a global scale. In addition, linkage should improve overall liquidity in the market-based CT program, foster broader regional and national participation, and perhaps create the means to achieve real overall global emission reduction in a timely and cost-effective manner. Linkage also may result in additional investment in zero- or low-emitting technologies in California and elsewhere, thereby creating the incentive to invest in the highest-valued projects from a GHG emission reduction perspective.

Compliance costs of California-obligated entities could increase if they are not allowed primary access to the requisite allowances to become compliant. This cost increase could occur if non-Californian actors purchased allowances needed in California. However, this risk is not limited to international actors. The same risk occurs if non-regulated entities such as financial institutions, hedge funds, and private citizens are allowed to participate in the initial primary auction for allowances. Accordingly, IEP has recommended allowing only entities that are required to comply with California's GHG reduction regulations to participate in the initial, primary means of allocations. Non-obligated entities can participate in the secondary market.

10. (5/6/08 Ruling) If linkage is allowed, should it be unilateral (where California accepts allowances and other credits from other carbon trading programs, but does not allow its own allowances and offsets to be used by other carbon trading programs) or bilateral (where California accepts allowances and other credits from other carbon trading programs and allows its allowances and offsets to be used by other carbon trading programs)?

Reciprocity should be the rule. However, achieving a tolerable level of reciprocity may be difficult. In the meantime, California should allow "offsets" from WCI "partners," which may include entities located outside the WCI geographic region under the principles and conditions outlined above, including the tests of (a) additionality and (b) verification.

11. (5/6/08 Ruling) If linkage is allowed, should allowances and other credits from other carbon trading programs be treated as offsets, such that any limitations applied to offsets would apply to such credits? If not, how should they be treated?

Yes.

E. Compliance Periods

12. (5/6/08 Ruling) What length of compliance periods should be used? Should compliance periods remain the same throughout the 2012 to 2020 period? Should compliance periods be the same for all entities and sectors? Should dates be staggered so that not all obligated entities have the same compliance dates?

IEP proposes a three-year rolling compliance period in which an individual point of regulation has up to three years to acquire the requisite allowances to match its GHG emissions profile. In order to create a mechanism that will establish a transparent and accurate MCP for the value of allowances, compliance periods should remain the same throughout 2012 to 2020 and be the same for all entities and sectors. In addition to the reasons provided above, obligated entities should maintain the same compliance dates, devoid of staggering, in order to avoid confusion within the system.

13. (5/6/08 Ruling) Should compliance extensions be granted? If so, under what circumstances?

Compliance extensions should be granted in extraordinary circumstances (i.e., natural disaster, failure of the system, unexpectedly high cost of compliance.

F. Banking and Borrowing

14. (5/6/08 Ruling) Should entities with California compliance obligations be allowed to bank any or all tradable units, including allowances, offsets, or credits from other carbon trading programs? Should entities that do not have compliance obligations be able to bank tradable units? If so, for how long and with what other conditions? Should allowances, offsets, or credits from other carbon trading programs banked during the program between 2012 and 2020 be recognized after 2020? If the California system joins a regional, national, or international carbon trading program, how should unused banked allowances, offsets, or credits from other carbon trading programs be treated?

Unlimited banking of permissible allowances and offsets should be allowed. Unlimited banking should be afforded non-obligated entities acquiring allowances and offsets in secondary markets.

15. (5/6/08 Ruling) Should limitations be placed on banking aimed at preventing or limiting market participants' ability to "hoard" allowances and offsets or distort market prices?

See IEP's response to Question 14.

16. (5/6/08 Ruling) Should entities with compliance obligations be allowed to borrow allowances to meet a portion of their obligation? If so, during what compliance periods and for what portion of their obligation? How long should they be given to repay borrowed allowances? Should there be penalties or interest payments? Should there be other conditions on borrowing, such as limitations on the ability to borrow from affiliated entities? Also address the extent to which borrowing might affect environmental integrity and emission reductions.

Borrowing works as a compliance tool only under a model in which obligated entities know for certain how many allowances they will acquire in the future. IEP supports the flexible compliance tools discussed above, including providing a three-year rolling compliance period. This effectively enables an obligated entity additional time to acquire allowances and, in this sense, represents a measure of borrowing.

G. Penalties and Alternative Compliance Payments

17. (5/6/08 Ruling) Should there be penalties for entities that fail to meet their compliance obligations? If so, how should the penalties be set? If not, what should be the recourse for non-compliance?

Assuming flexible compliance tools are employed as recommended by IEP, obligated entities must face some sanction for being out of compliance with a regulatory mandate.

- If auctioning of allowances is the adopted policy, IEP recommends setting the penalty for non-compliance at the MCP for allowances when allowances are initially allocated by the appropriate regulatory agency in the last year that the regulated entity is entitled to acquire allowances, plus 10 percent. For example, if a three-year flexible compliance mechanism is employed and obligated entities have until 2015 to acquire allowances for the 2012 compliance period, then penalty would be equivalent to the MCP for allowances in 2015, plus 10 percent.
- If administrative allocations are the adopted policy, alternative means may need to be explored.

Penalty revenues should be re-invested in zero- or low-emitting infrastructure. Revenue recycling should not be employed to mitigate retail rate impacts, as this will undercut the purpose of the penalty (i.e., retail providers with generation interests will simply be recycling revenues back to themselves).

18. (5/6/08 Ruling) Instead of penalties, should there be alternative compliance payments? What would be the distinguishing attributes of alternative compliance payments versus penalties? How would the availability of alternative compliance payments affect the environmental integrity of the cap?

If the point of regulation is the "deliverer," including electric generators, it is not clear what "alternative compliance payments" would prove more satisfactory. As noted elsewhere, electric generators confronting required GHG emission reductions have effectively two choices: (a) reduce operations in order to lower overall emissions or (b) acquire allowances for the emissions that have occurred or will occur. Alternative compliance payments would simply be another way of "pricing" the value of an allowance. In either case, it is critical that electric generators have a reasonable means to recover all costs of compliance or grid reliability may suffer.

19. (5/6/08 Ruling) Would penalties and/or alternative compliance payments allow obligated entities to opt out of the market? Would this add too much uncertainty for other market participants?

By definition, penalties and alternative compliance payments are a means to price the market value of allowances. The extent to which they are present in the marketplace will drive the MCP for allowances. Certainly, the presence or absence of such tools will affect the volatility of the market which in turn will create a measure of uncertainty for market participants.

20. (5/6/08 Ruling) How should California use the money that would be generated by penalties and/or alternative compliance payments?

The money should be re-invested in zero- or low-emitting electric generation infrastructure. IEP has two primary reasons for making this proposal.

1. If the funds collected from the program are not re-invested in the program, then what's the purpose of the program? Re-directing revenues away from AB 32 goals will simply mean that attainment of the goals will take longer and be more costly than is necessary.
2. Use of money generated by the program (whether through an allocation of policy, penalties, or alternative compliance payments) for purposes unrelated to the AB 32 appears inconsistent with the requirement that regulatory fees (as distinct from taxes) must "not exceed the reasonable cost of providing services necessary to the activity for

which the fee is charged and which are not levied for unrelated revenue purposes."[32]

H. Offsets

21. (5/6/08 Ruling) Should California allow offsets for AB 32 compliance purposes?

IEP endorses a California policy establishing an offset program for AB 32 compliance purposes. The principles that IEP views as necessary for the proposed offset program are:

- Offsets must be additional and verifiable,
- "A ton is equivalent to a ton" from the perspective of emission reductions, such that an offset is equal to an allowance,
- Offsets should be permanent with no vintaging,
- Offsets should be exchangeable or tradable within carbon reduction programs including the WCI Partnership and non-contiguous entities deemed to be partners by the WCI, including the EU, RGGI, etc.

Under the stipulation that an offset can be deemed "additional" and "verifiable," IEP recommends that there should not be a policy that limits offsets by geography or locational preference. Along these same lines, voluntary GHG emission reduction projects should be permitted as offsets.

The offset program must be administered through a third party responsible for determining if the offset is indeed "additional" and "verifiable."

In regards to allowing discount credits, IEP understands this term to refer to treating some credits or offsets equal to an allowance (i.e., a ton is a ton) and other credits or offsets as something less than the value of an allowance (i.e., equal to a half ton). IEP supports the principle that "a ton is a ton" such that an offset used within the CT program should be treated as equal to an allowance. "Discounted" allowances should be allowed within the CT program. If

[32] *Sinclair Paint Co. v. State Bd. of Equalization*, 15 Cal.4th at 876, quoting *Pennell v. City of San Jose* (1986) 42 Cal.3d 365, 375.

certain offset activities result in less than a ton of emissions reduction, the CT program should consider providing a means to aggregate these activities in a manner that creates an equivalent ton of emission reduction (while meeting the tests of additionality and verification) sufficient for entry into the CT program. On the other hand, "discounting" of allowances creates an uncertainty about the actual emission reductions achieved from offsets that will be detrimental to the program at large.

22. (5/6/08 Ruling) If offsets are permitted, what types of offsets should be allowed? Should California establish geographic limits or preferences on the location of offsets? If so, what should be the nature of those limits or preferences?

Under the stipulation that an offset must be "additional" and "verifiable," IEP recommends that offsets should not be limited by geography scope or locational preference. Along these same lines, voluntary GHG emission reduction projects should be permitted as offsets.

23. (5/6/08 Ruling) Should voluntary GHG emission reduction projects, i.e., projects that are not developed to comply with governmental mandates, be permitted as offsets if they are within sectors in California that are not within the cap-and-trade program? In particular, should voluntary GHG emission reduction projects within the natural gas sector in California be permitted as offsets, if the natural gas sector is not yet in the cap-and-trade program?

Yes. Under the stipulation that an offset must be "additional" and "verifiable," IEP recommends that there should not be a policy that limits offsets by geography or locational preference. Along these same lines, voluntary GHG emission reduction projects should be permitted as offsets.

24. (5/6/08 Ruling) Should there be limits to the quantity of offsets? If so, how should the limits be determined?

No. Under the stipulation that an offset must be "additional" and "verifiable," IEP recommends that there should not be a policy that limits offsets by geography or locational preference. Along these same lines, voluntary GHG emission reduction projects should be permitted as offsets.

25. (5/6/08 Ruling) How should an offsets program be administered? What should be the project approval and quantification process? What protocols should be used to determine eligibility of proposed offsets? Are existing protocols that have been developed elsewhere acceptable for use in California, or is additional protocol development needed? Should offsets that have been certified by other trading programs be accepted? Should use of CDM or Joint Implementation credits be allowed?

The principles that IEP views as necessary for the proposed offset program are as follows:

- Offsets must be additional and verifiable;
- "A ton is equivalent to a ton" from the perspective of emission reductions, such that an offset is equal to an allowance;
- Offsets should be permanent with no vintaging (e.g. once created, an offset may be employed for purposes of regulatory compliance at any time); and
- Offsets should be exchangeable or tradable within carbon reduction programs including the WCI Partnership and non-contiguous entities deemed to be partners by the WCI, including the EU, RGGI, etc.

26. (5/6/08 Ruling) Should California discount credits (i.e. make the credits worth less than a ton of CO2e) from some offset projects or other trading programs to account for uncertainty in emission reductions achieved? If so, what types of credits would be discounted? How would the appropriate discount be quantified and accounted for?

No. A ton is a ton.

I. Legal Issues

27. (5/6/08 Ruling) Under AB 32, is it permissible for GHG emission allowances from non-California carbon trading programs or offsets from GHG emission sources outside of California to be used instead of GHG emission allowances issued in California? Please consider especially the provisions of Health and Safety Code Sections 3805, 38550, and 38562(a) added by AB 32.

AB 32 gives CARB authority to adopt "market-based compliance mechanisms" to help ensure that the goals of AB 32 are achieved.[33] Market-based compliance mechanisms include "greenhouse gas emissions exchanges, banking, credits, and other transactions . . . that result in the same greenhouse gas emission reduction, over the same time period, as direct compliance with a greenhouse gas emission limit or emission reduction measure" adopted by CARB. This language is broad enough to include carbon trading programs and offsets from sources outside of California, provided that (1) CARB adopts "rules and protocols" governing these flexible compliance mechanisms and (2) the GHG reduction occurs over the same time period as compliance with a direct limit or reduction measure.[34]

Under AB 32, an "allowance" is "an authorization to emit, during a specified year, up to one ton of carbon dioxide equivalent."[35] CARB has the authority to "distribute emissions allowances where appropriate, in a manner that is equitable."[36] Because only CARB has the statutory authority to distribute allowances that "count" for purposes of AB32, CARB would presumably authorize use of GHG emission allowances from non-California carbon trading programs only in exchange for corresponding emissions reductions, which might be located outside of California. With this clarification, CARB could decide to accept allowances from non-California trading as part of its effort "to minimize costs and maximize the total benefits to California" as it implements AB 32.

CARB's authority to adopt market-based compliance mechanisms also appears to extend to out-of-state offsets that comply with CARB's rules and protocols and that occur over the same time period as compliance with a direct limit or reduction measure.

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[33] Health & Safety Code § 38570(a).
[34] Health & Safety Code § 38505(k)(2).
[35] Health & Safety Code § 38505(a).
[36] Health & Safety Code § 38562(a).

While incorporating out-of-state carbon trading programs and offsets into the array of CARB's compliance mechanisms is consistent with the goals of AB 32, other statutory language could be read as limiting CARB's authority. Specifically, "statewide greenhouse gas emissions" is defined as "the total annual emissions of greenhouse gases in the state, including all emissions of greenhouse gases from the generation of electricity delivered to and consumed in California . . . , whether the electricity is generated in state or imported."[37] Interpreting this language to require a narrow focus on reducing GHG emissions "in the state" could limit CARB's authority and contradict CARB's broad authority to adopt market-based compliance mechanisms.

IEP concludes that it makes more sense to read the language referring to "the total annual emissions of greenhouse gases in the state" as an effort to ensure that jurisdictional boundaries were respected, *i.e.,* to ensure that AB 32 could not be read as authorizing an encroachment into the jurisdiction of other states or the federal government. The Legislature clearly recognized that GHGs are a global problem and that atmospheric dynamics do not respect the boundaries of the state. For example, AB 32 required CARB to consult with other states, the federal government, and other nations to "facilitate the development of integrated and cost-effective regional, national, and international greenhouse gas reduction programs."[38] It would be pointless for CARB to work to develop these broader programs if it were prohibited from making use of the mechanisms that might be made available by these programs.

Thus, the definition of "statewide greenhouse gas emissions" should not be read to restrict CARB's ability to incorporate appropriate out-of-state carbon trading programs or offsets

[37] Health & Safety Code § 38505(m).
[38] Health & Safety Code § 38564.

into its flexible compliance mechanisms in pursuit of the goal implementing AB 32 in a way that minimizes the costs and maximizes the total benefits to California.

28. (5/6/08 Ruling) Do any of the flexible compliance options identified in these questions or discussed in the attachments to this ruling or in your opening comments raise concerns under the dormant Commerce Clause? If so, please explain why that flexible compliance option(s) may violate the Commerce Clause, including citations to specific relevant legal authorities. Also, explain if and, if so, how the flexible compliance option(s) could be modified to avoid the Commerce Clause problem. Address, in particular, whether a policy that limits offsets to only emission reduction projects located in California would raise dormant Commerce Clause concerns.

The flexible compliance options do not run afoul of the Commerce Clause if they are rationally related to a legitimate local (state) purpose; if they appear neutral and do not unreasonably discriminate against out-of-state suppliers or in favor of California suppliers; and if they do not impose an excessive burden on interstate commerce.[39] The GHG reductions that are the goal of AB 32 are rationally related to the state's health and safety authority, which is a legitimate state purpose, and the proposed flexible compliance mechanisms appear to be an effort to simplify the achievement of those goals. As discussed above, imported power may qualify for GHG allowances and offsets, and if CARB does not set any unduly discriminatory restrictions on the use of out-of-state offsets that are clearly linked to imported power, or, alternatively to out-of-state suppliers' access to the California CT market, it does not appear that out-of-state suppliers would be unreasonably disadvantaged by the flexible compliance mechanisms. One issue that might arise is whether out-of-state offsets linked to imported power could be traded as part of the cap and trade mechanism with in-state offsets. If so, out-of-state suppliers would not be the subject of undue discrimination. If out-of-state offsets are not part of the cap-and-trade system, the result could be an impermissible discrimination against out-of-state suppliers, but

[39] See *Pike v. Bruce Church* (1970) 397 U.S. 137, 142.

that concern is diminished if out-of-state suppliers have reasonable access to the California CT market.

29. (5/6/08 Ruling) Do any of the linkage options identified in these questions or discussed in the attachments to this ruling or in your opening comments raise concerns under either the Compact Clause or the Treaty Clause of the United States Constitution? If so, please explain why that linkage option(s) may violate one or both of these Clauses, including citations to specific relevant legal authorities. Also, explain if and, if so, how the linkage option(s) could be modified to avoid the Compact Clause and/or Treaty Clause problem.

IEP has no comment on this issue.

30. (5/6/08 Ruling) Do any of the flexible compliance options identified in these questions or discussed in the attachments to this ruling or in your opening comments, raise any other legal concerns? If so, please explain the legal concern(s), including citations to specific relevant legal authorities. Also, explain if and, if so, how the flexible compliance option(s) could be modified to avoid the legal concern(s).

IEP has no comment on this issue.

31. (5/6/08 Ruling) For reply comments: do any of the flexible compliance options identified by other parties in their comments raise legal concerns? If so, please explain the legal concern(s), including citations to specific relevant legal authorities. Also, explain if and, if so, how the flexible compliance option(s) could be modified to avoid the legal concern(s).

[For reply comments]

V. TREATMENT OF CHP

A. Detailed Proposal

1) (5/1/08 Ruling) Taking into account and synthesizing your answers to other questions in this paper, explain in detail your proposal for how GHG emissions from CHP facilities should be regulated under AB 32.

As to the regulation of Combined Heat and Power (or cogeneration as CHP is referred to in the CARB mandatory reporting regulations) facilities, IEP recommends that the Commission keep it simple and look to the mandatory reporting guidelines promulgated by CARB. The CARB guidelines provide clear direction for the allocation of GHG emissions between thermal energy use and electrical production.

The CARB guidelines should be used for determining emission compliance for both the electric sector and the sector encompassing the thermal host. To the extent that the electric sector and the thermal host sector are both included in the CT program, allowances would be required for the total amount of GHG emissions. If the cogeneration facility is very efficient, as it should be, the overall GHG emissions, and thus the burden of acquiring allowances, will be reduced as compared to the separate production of useful thermal energy and electricity.

In the event that the electric sector is included in the CT program but the thermal host's sector is not, only allowances for the emissions associated with the electric sector would be required. However, as mentioned elsewhere in these comments, IEP questions the efficacy of a CT program that exempts major sectors from participation.

To the extent that the Commission wants to encourage cogeneration as an emission reduction strategy, it can do so most efficiently by directing the utilities under its jurisdiction to make available commercially executable standard form power purchase agreements, as it directed in D.07-09-040.

B. Regulation of CHP GHG Emissions

IEP has no comments on this issue at this time.

C. CHP as an Emission Reduction Measure

IEP has no comments on this issue at this time.

D. Legal Issues

IEP has no comments on this issue at this time.

IEP has no comments on this issue at this time.

VI. NON-MARKET-BASED EMISSION REDUCTION MEASURES (OTHER THAN CHP) AND EMISSION CAPS

A. Electricity Emission Reduction Measures

1. (5/13/08 Ruling) What direct programmatic or regulatory emission reduction measures, in addition to current mandates in the areas of energy efficiency and renewables, should be included for the electricity and natural gas sectors in ARB's Assembly Bill (AB) 32 scoping plan?

As noted elsewhere, as long as electric generators are the "point of regulation," then few additional measures are available to reduce direct GHG emissions from electric generators other than (a) acquiring allowances or (b) reducing operations (which potentially raises concerns regarding grid reliability). IEP notes, however, that other state agencies may be considering various regulatory initiatives that may have the effect of increasing GHG emissions from the electric sector. For example, initiatives to reduce "once through cooling," where certain electric generators would be required to move from water-cooled to air-cooled systems, is expected to result in an increase in GHG emissions, all else being equal.

2. (5/13/08 Ruling) Are there additional regulations that ARB should promulgate in the context of implementing AB 32, that would assist or augment existing programs and policies for emission reduction measures in the electricity and natural gas sectors?

IEP refers to its response to Question 3 (5.13.08 Ruling), set forth in Section II, above.

5. (5/13/08 Ruling) What percentage of emission reductions in the electricity sector should come from programmatic or regulatory measures, and what percentage should be derived from market-based measures or mechanisms? What criteria should be used to determine the portion from each approach? By what approach and in what timeframe should this question be resolved?

Because the California electric fleet is relatively clean and low-emitting, as a practical matter there is little improvement that may be obtained in the short term. As indicated by early stage E3 modeling, carbon values have to rise to at least $60/ton before natural gas-fired generation begins to displace coal-fired generation. The price must rise to $120 ton/ton before renewables begin to displace natural gas. This finding suggests that the CT program may have little effect in modifying the electric generation fleet and, therefore, the bulk of emissions reduction will derive from the transformation of the entire fleet through successful, yet relatively time consuming, implementation of the RPS, repowering of aged power plants, etc. Accordingly, IEP recommends setting the cap at a level that recognizes a practical reliance on technology transformation over time, rather than imposes a drastic reduction in the availability of allowances for electric generators, reflecting a recognition of the historical fact that many RPS generation and energy efficiency resources have had difficulty becoming operational on expected timelines.

B. Natural Gas Emission Reduction Measures

1. (5/13/08 Ruling) What direct programmatic or regulatory emission reduction measures, in addition to current mandates in the areas of energy efficiency and renewables, should be included for the electricity and natural gas sectors in ARB's Assembly Bill (AB) 32 scoping plan?

IEP's responses to this question are set forth in section A, above.

2. (5/13/08 Ruling) Are there additional regulations that ARB should promulgate in the context of implementing AB 32, that would assist or augment existing programs and policies for emission reduction measures in the electricity and natural gas sectors?

IEP's responses to this question are set forth in section A, above.

C. Annual Emission Caps for the Electricity and Natural Gas Sections

4. (5/13/08 Ruling) The scope of this proceeding includes making recommendations to ARB regarding annual GHG emissions caps for the electricity and natural gas sectors. What should those recommendations be? What factors (e.g., potential effectiveness of identified emission reduction measures, rate impacts for electricity and natural gas customers, abatement cost in other sectors, anticipated carbon prices) should the Commissions consider in making GHG emissions cap recommendations? If sufficient information is not currently available to recommend cap levels, what cap-related recommendations should the Commissions make to ARB for inclusion in its scoping plan?

The electricity sector should not be required to reduce emissions more than its fair share.

Presently, the electricity sector represents approximately 20% of the total statewide emissions level. The electricity sector cap should be designed to ensure that the electricity sector's contributions to emission reduction are commensurate with the sector's total GHG emissions.

As noted elsewhere, IEP has raised significant concerns regarding the impact of AB 32 implementation on grid reliability. Accordingly, IEP recommends use of (a) flexible compliance tools and (b) an emergency reserve to protect against extreme volatility in the CT market. The electric sector cap should account for the realities of powerplant operations, including the fact that generators do not control their operations entirely in real time.

The availability of allowances to the electric sector also must reflect the extent to which the electrification of the transportation sector is accomplished. While IEP supports this goal, in a GHG world the electrification of the transportation sector has the effect of shifting the burden from one sector to another, akin to "leakage." As the electrification of the transportation sector occurs, electric sector demand concomitantly increases. This dynamic needs to be addressed when determining the scope and scale of allowances made available to the electric sector.

D. Legal Issues

IEP has no comments on these issues at this time.

VII. MODELING ISSUES

A. Methodology

8. (5/13/08 Ruling) Address the performance and usefulness of the E3 model. Is it sufficiently reliable to be useful as the Commissions develop recommendations to ARB? How could it be improved?

9. (5/13/08 Ruling) Address the validity of the input assumptions in E3's reference case and the other cases for which E3 has presented model results. If you disagree with the input assumptions used by E3, provide your recommended input assumptions.

As to Question 8, IEP is not in a position to assess the reliability of the model given the substantial changes E3 has made to the GHG calculator between Version 1 and Version 2a and again between Version 2a and 2b. Substantial additional changes were made in the seven days between the release of Version 2a and Version 2b. Unfortunately, there has been no opportunity provided by the Commission for open, all-party discussion of the breadth and depth on the changes between Version 2a and 2b. IEP will address the balance of Question 8 and Question 9 in the course of the following discussion of what IEP has discovered during the course of its examination of the model.

Overview

The Commission has engaged E3 to develop a model to allow parties to assess the implications of various resource addition scenarios, views on allowance costs and other aspects of a carbon market, and allowance distribution schemes and treatment of any revenue generated through the auctioning of allowances within the electric sector.

IEP recognizes the amount of effort E3 has put into this effort, however, as discussed below, the combination of faulty underlying assumptions and inherent limitations of the model counsel against heavy reliance on it by the Commission for its recommendations to CARB. Nonetheless, IEP believes the GHG Calculator can be useful in examining a limited set of issues.

Discussion

IEP has been an active participant in Stage 2 of the E3 modeling efforts and we are troubled by an underlying theme that the modeling has ostensibly demonstrated. That theme or message is that, because CO2 allowance costs will be reflected in the electricity MCP, independent generators earn "windfall" profits. E3 estimates the cost to California ratepayers of this "producer surplus effect" to be approximately $700 million per year.[40] The implications of

[40] E3 PowerPoint presentation, May 13, slide 25.

these findings are troubling, as they seem to indicate that UOG is a preferable path to generation resource development because it is assumed that utilities (along with purchases from long-term contracts) do not capture this surplus. IEP believes that the magnitude of this effect has been significantly overstated, and as we discuss *infra,* corrected assumptions lead to a conclusion that any so-called "producer surplus problem" is minimal, and that the utilities should be encouraged to enter into long term contracts that accommodate dollar for dollar compensation for any CO2 allowance cost incurred by the supplier.[41]

As stated by E3, its GHG Calculator is intended as a policy tool, not a resource planning tool. E3 notes that one of the requirements for reasonable accuracy for CO2 policy decisions is assumptions that reflect "approximately correct generation or purchases from 3 categories of generators

- Utility-owned generation
- LongTerm contracts
- Imports"[42]

IEP has reviewed the assumptions underlying the model, to the extent they were made available.[43] The assumptions regarding generator assignment appear unreasonable and lead to substantially overstated estimates of the impact of CO2 allowance costs on MCP, on total utility costs, and on the magnitude of any producer surplus derived windfall profits. Simply put, far too many resources are assumed to be selling through the "market" or "pool" without long-term contracts. These resources include many existing renewables and other QF resources whose contracts expire prior to 2020, as well as all of the incremental renewable generation assumed to

[41] E3 acknowledges that its analysis is significantly affected by contract assignment assumptions, Ibid.

[42] Ibid. slide 27.

[43] The datasets underlying the production simulation aspects of the E3 effort were not made available to IEP or its consultant.

come online between now and 2020, including 1577 MW of geothermal, 863 MW of solar and 4,293 MW of wind. These assignments are shown on the "2020" tab of the E3 GHG calculator.

The result of these generator assignment assumptions is that the utilities are assumed to be purchasing substantial amounts of their energy requirements on the spot market, many times more than the five percent guideline established by the Commission in D.02-10-062.

In order to test the impacts of this assumption on total utility cost and the cost increase attributed to the inclusion of CO2 allowance costs in the MCP, IEP modified the generator assignments specified in the "2020" tab of the GHG Calculator.[44] The modifications consisted of reassigning generators from the Northern CA Powerpool and the Southern CA Powerpool to particular utilities. This reassignment results in marked reduction to the utilities' reliance on pool purchases. Table 1 below show the assumed sales for each utility, the original assumptions regarding reliance on pool energy to satisfy demand and the revised assumptions resulting for IEP's reassignment of generation. Figure 1 depicts the data graphically.

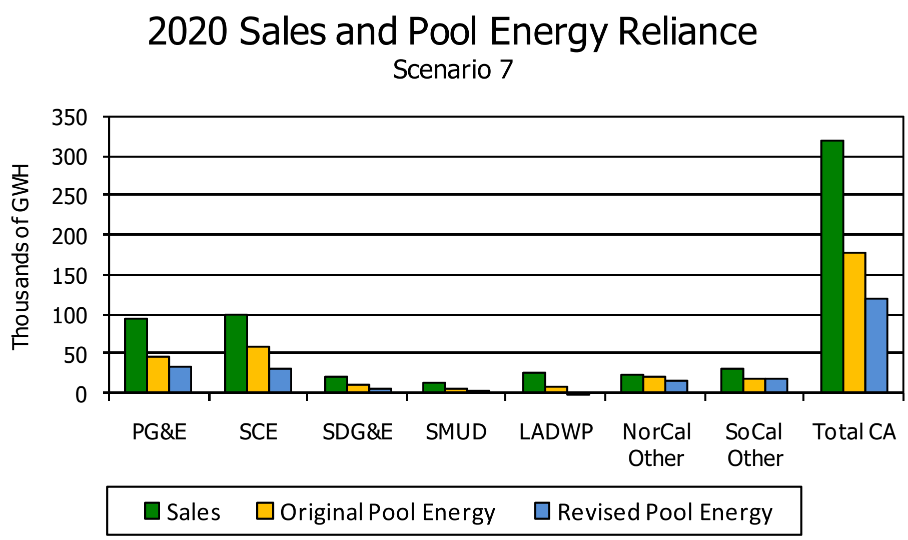
[44] A spreadsheet file that highlights the changes made by IEP is being served with these comments. This file can be copied into the 2020 tab on the GHG Calculator to replicate IEP's results.

Table 1

2020 Reliance on Non-contracted Pool Energy

	PG&E	SCE	SDG&E	SMUD	LADWP	NorCal Other	SoCal Other	Total CA
Sales	95,046	99,268	21,143	13,148	26,070	23,942	29,603	320,519
Pool Reliance								
Original Assumption								
GWH	46,133	59,562	10,314	3,810	6,431	21,497	18,398	178,445
% of Sales	48.5%	60.0%	48.8%	29.0%	24.7%	89.8%	62.2%	55.7%
Revised Assumption								
GWH	34,735	31,382	6,904	3,486	1,250	16,002	18,154	121,118
% of Sales	36.5%	31.6%	32.7%	26.5%	4.8%	66.8%	61.3%	37.8%
Difference								
GWH	-11,398	-28,180	-3,410	-324	-5,181	-5,494	-244	-57,326
% reduced reliance	-24.7%	-47.3%	-33.1%	-8.5%	-80.6%	-25.6%	-1.3%	-32.1%

Figure 1



Although IEP's modifications have not resulted in reducing pool purchases to the Commission recommended 5 percent level, they have moved pool purchases closer to that standard, and for purposes of these comments are sufficient to demonstrate why the producer surplus windfall profit issue is at worst *de minimus.*

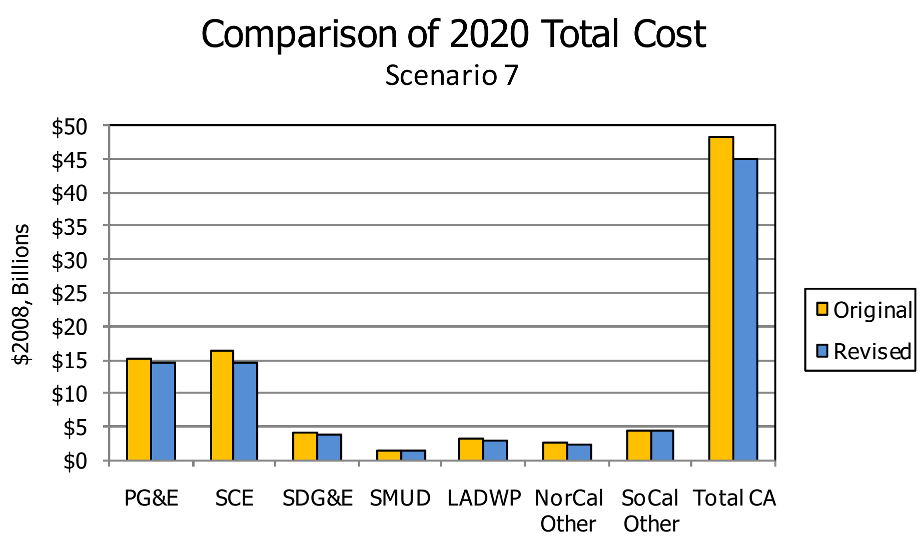
In addition to reduced reliance on pool energy purchases, IEP's modifications have resulted in reduced total costs for nearly every utility in California on a scenario on scenario comparison.[45] SCE's total costs are shown to decline by nearly 12 percent, as are LADWP's. Statewide, the model forecasts total costs to decline by a little better than 7 percent. These results are shown in Table 2 and on Figure 2.

Table 2

2020 Total Cost Comparison
($ millions)

	PG&E	SCE	SDG&E	SMUD	LADWP	NorCal Other	SoCal Other	Total CA
Original Pool Energy	$15,062	$16,467	$4,109	$1,501	$3,316	$2,651	$4,384	$48,355
Revised Pool Energy	$14,683	$14,503	$3,846	$1,484	$2,942	$2,373	$4,392	$44,869
Difference								
$	-$379	-$1,964	-$263	-$16	-$374	-$277	$8	-$3,486
%	-2.5%	-11.9%	-6.4%	-1.1%	-11.3%	-10.5%	0.2%	-7.2%

Figure 2



While the modifications to generator assignment undertaken by IEP have produced modest reductions to total utility cost for the scenario examined, their impact on CO2 allowance cost effects on MCP and thus the perceived producer surplus is substantial. On a statewide basis the cost increases resulting from the inclusion of CO2 allowance costs in the MCP are reduced

[45] For purposes of these comments IEP focused solely on Scenario 7.

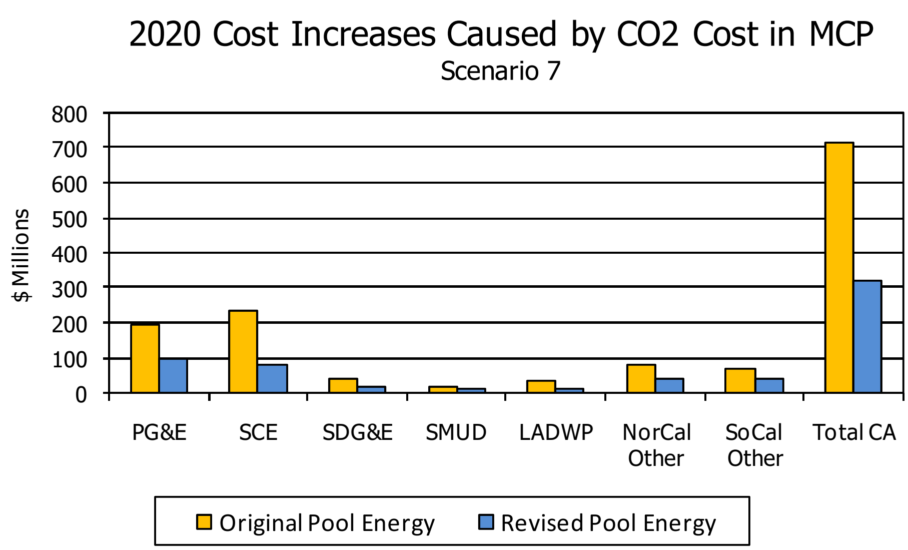
by more than 50 percent, from $716 million in 2020 to $318 million. IEP is confident that with further thought as to generator assignment to move pool purchases much nearer the 5 percent guideline, any producer surplus will be all but eliminated. Table 3 and Figure 3 show the differences in CO2-induced MCP costs between the original generator assignment and IEP's revised assignment.

Table 3

2020 Cost Increases Caused by CO2 Cost in MCP

	PG&E	SCE	SDG&E	SMUD	LADWP	NorCal Other	SoCal Other	Total CA
Original Pool Energy	$197	$232	$40	$15	$35	$82	$70	$716
Revised Pool Energy	$97	$82	$17	$9	$11	$39	$43	$318
Difference								
$	-$100	-$150	-$23	-$6	-$25	-$43	-$27	-$398
%	-51%	-65%	-57%	-42%	-70%	-53%	-39%	-56%

Figure 3



IEP believes that the changes it has made in generator assignment are justifiable and may actually be quite conservative. First, it is unreasonable to assume that nearly 7,000 MW of new renewable generation will be developed without either long-term contracts or direct utility involvement in the development effort. In either case, these resources will not be selling energy in the pool; instead the energy will be used to meet the load and RPS obligations of the purchasing/owning utility. Second, there is every reason to expect that expiring QF contracts will be recontracted in some form or another, especially renewable QFs. In the last long-term procurement proceeding, PG&E and SCE took the position that 90% of their QFs with expiring contracts would re-contract, and the Commission required all utilities to maintain the current levels of QF capacity through the next decade.[46]

Some might argue that generator assignment is irrelevant since new resources and existing resources with expiring contracts will attempt to capture their perception of producer surplus in the prices they offer during contract negotiation, and thus the distinction between pool purchases and contracted energy is nil. This argument fails for several reasons.

- First, that argument insults the negotiating acumen of the purchasing utility and overlooks its demonstrated monopsony position in the power market.
- Second, as has been demonstrated by fixed-price arrangements freely negotiated between large segments of the QF community and both PG&E and SCE, independent power producers, especially renewables, are willing to give up potential market upside in exchange for pricing stability to avoid the volatility associated with short-term market pricing.
- Third, to the extent that resources are developed by publicly owned utilities (many of which have a demonstrated tendency to develop their own resources rather than enter into power purchase agreements), this phenomenon is mitigated through the POUs' procurement strategy.
- Finally, to the extent that non-renewable resources are not contracted or contracted with provisions for energy pricing at "market rates," there will be little producer surplus to capture since they will also be required to incur expenses to acquire allowances.

Other Model Issues

[46] D.07-12-052, pp. 83-85.

During the course of its review of the E3 GHG Calculator IEP has identified a number of aspects of the model that should be recognized as potential limitations with regard to the breadth of issues that can be addressed by the model.[47] These are listed below.

- Demand Response. The GHG Calculator does not incorporate automated demand response to changes in rates.
- Response to Allowance prices. The only outcome resulting from changed assumptions regarding allowance costs is the volume of money collected from generators. At prices of $5.00 per ton or $500.00 per ton, dispatch and resource addition decisions are unchanged; only the costs change.
- Allowance Availability. The model assumes that there will always be sufficient allowances available for the CO2 emissions of the electric sector, regardless of price. If that is the case, then the so-called cap and trade program amounts to no more than a tax.

B. Inputs

See responses in preceding section.

C. Results Reported by E3

D. Additional Modeling and Scenarios to Support Parties' Comments

2970/019/X100063.v2

[47] IEP in no way intends to demean the efforts of E3 in its creation of the GHG Calculator. However, it must be recognized that there is only so much one can do with a spreadsheet. These comments are intended to make the Commission aware of our views on some of the limitations of the tool so as to provide guidance as to the extent to which the model can be relied on as the Commission develops its recommendations to CARB.

CERTIFICATE OF SERVICE

I, Melinda LaJaunie, certify that I have on this 2nd day of June 2008 caused a copy of the foregoing

COMMENTS OF THE INDEPENDENT ENERGY PRODUCERS ASSOCIATION ON EMISSION ALLOWANCE ALLOCATION, FLEXIBLE COMPLIANCE, AND COMBINED HEAT AND POWER

to be served on all known parties to R.06-04-009 (and CEC Docket 07-OIIP-01) listed on the most recently updated service list available on the California Public Utilities Commission website, via email to those listed with email and via U.S. mail to those without email service. I also caused courtesy copies to be hand-delivered as follows:

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I declare under penalty of perjury that the foregoing is true and correct. Executed this 2nd day of June 2008 at San Francisco, California.

/s/ Melinda LaJaunie
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2970/019/X100067.v1

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