BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

CEC Docket no. D.07-OIIP-01

COMMENTS OF THE GREEN POWER INSTITUTE ON ALLOCATION, MODELING, AND FLEXIBLE COMPLIANCE

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I. Summary

Pursuant to the April 16, 2008 *Administrative Law Judge's Ruling Updating Proceeding Schedule and Requesting Comments on Emission Allowance Allocation Policies and Other Issues*, and five follow-up ALJ's *Rulings* issued on April 22, May 1, May 6, May 13, and May 20, the Green Power Institute (GPI) respectfully submits these *Comments of the Green Power Institute on Allocation, Modeling, and Flexible Compliance*, in R.06-04-009, the **Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies**. Our Comments focus on the issues of allocation and distribution of greenhouse-gas emissions allowances in a California cap-and-trade program, flexible compliance, emissions reduction measures, and the E3 greenhouse-gas calculator model. We follow the outline for comments provided in the May 20, 2008, ALJ's *Ruling*, and we address selected issues from among all of the issues that were placed on the table by the six governing *Rulings*.

II. General Issues

AB 32 is trailblazing legislation that requires California to do something that has not previously been attempted in the US – reduce society's greenhouse-gas emissions. AB 32 has memorialized into statute an ambitious goal for the state, which is to reduce statewide greenhouse gas emissions to the 1990 level by 2020, which will require a variety of policy measures to achieve. The program is scheduled to go into effect at the beginning of 2012, which is only about 3½ years away. This leaves a limited amount of time in which to accomplish an enormous amount of work. The GPI is a strong supporter of enacting the program as envisioned in the legislation, but we are concerned that the extreme time pressure that all of the principal state agencies and participating parties are under could lead to mistakes and missteps that might ultimately jeopardize the viability of the program.

The six ALJ's *Rulings* governing the present round of comments and replies cover some of the most consequential areas of the design of a greenhouse-gas cap-and-trade program. The issues covered are literally the BIG-TICKET items when it comes to market design. We understand the time pressure that the joint Commissions (PUC, CEC) are under to produce recommendations to the ARB, which itself is under the gun. We regret that in the timeframe available we were unable to address all of the issues in the *Rulings* that we consider to be important.

The GPI's overall recommendation on the design of a greenhouse-gas emissions cap-and-trade program for California is that it is of the utmost importance to get it right the first time. Adjustments and fine tuning are a normal part of the process of introducing as new, sweeping regulatory program, but substantial flaws in program design and implementation that go undetected before rollout can doom the program's ultimate viability.

III. Allowance Allocation

The recent Decision in this proceeding on AB 32 regulation of the electricity and natural-gas sectors, Decision D.08-03-018, discusses some of the issues that must be addressed in determining how to allocate and distribute greenhouse-gas emissions allowances in conjunction with the establishment of a cap-and-trade system in California. Nevertheless, D.08-03-018 does not make a comprehensive recommendation about allocation and distribution, citing an as-yet insufficient record on which to base such a recommendation. The present round of *Comments* and *Reply Comments* is intended to fill-in the record, in order to allow the PUC and CEC to make a joint recommendation to the ARB.

III. A. Detailed Proposal

In the GPI's February 28, 2008, *Comments on the PD*, in this proceeding, we pointed out that an important allocation alternative, administrative allocation of purchasing rights for emissions allowances, was overlooked in the discussion in the PD on the possible options for the allocation and distribution of allowances. This oversight was corrected in the text of the final Decision, D.08-03-018:

> The alternative to selling emission allowances through auction is administrative allocation, either to deliverers or potentially to other entities such as retail providers. Emission allowances could be allocated free of charge, or rights to purchase allowances at a set fee could be distributed (D.08-03-018, pg. 94).

Despite the Commission's affirmative acknowledgement of the option of administratively allocating purchase rights to emissions allowances in D.08-03-018, the *Joint California Public Utilities Commission and California Energy Commission Staff Paper on Options for Allocation of GHG Allowances in the Electricity Sector* (Staff Paper), which is an attachment to the April 16 *Ruling*, chooses to limit its consideration of administrative allocation of greenhouse-gas emissions allowances to free distributions:

> Previously in this proceeding, the Commissions received comments from parties that proposed certain allocation methods that have not been employed to our knowledge and that have been subjected to much less analysis in the economic literature. These proposals are not discussed in this paper. They may have merit, but we have fewer tools and historical examples to assess them. The proposals include the "economic harm" method suggested by Southern California Edison, an allocation of rights to purchase allowances at a fixed price suggested by the Green Power Institute, and an allocation of allowances to all Californians on an equal per capita basis submitted by the Climate Protection Campaign. While parties to this proceeding are free to provide more information and analysis of these options, we do not pursue them further in this paper (page 12).

Although our proposal for the administrative allocation of purchasing rights to greenhouse-gas emissions allowances may not be considered explicitly in the background literature that has been entered into the record of this proceeding, it is certainly a standard market mechanism that is in common use in the real-world marketplace.[1] Indeed, our proposal is, in effect, an amalgam of the administrative allocation options considered in the Staff Paper, and the distribution mechanism used in conjunction with the auction options considered in the Staff Paper (sales of allowances to auction winners).

In the current energy market, in which greenhouse gases are not yet regulated, it is generally acknowledged that the marginal energy source for most of the hours of the year is fossil fuel. As fossil carbon emissions are squeezed out of the system as a result of the

[1] In our October 31, 2007, *Comments* in this proceeding, we offered the example of allocating and distributing a limited pool of playoff tickets by a combination of administrative allocation of purchase rights to season-ticket holders, and auction by lottery of the remaining ticket rights to the general public.

implementation of AB 32, lower and/or zero-greenhouse gas emitting sources, including efficiency, will have to increase their collective share of the overall supply mix. As this process proceeds, and regardless of the details of the allocation system for emissions allowances that is eventually adopted, emissions allowances will take on all of the characteristics of a commodity. We suggest that these allowances be treated as the commodities that they are from the start. In our opinion, giving the emissions allowances away without charge to the recipients would represent a poor policy choice that is not in the public interest, equivalent to giving away public assets or resources.

As long as the state is attempting to ramp-down greenhouse-gas emissions, greenhouse-gas allowances will be valuable commodities. If they are distributed free of charge to either retailer sellers or generators, the intrinsic value of the allowances will represent a form of windfall to the recipient entity, a windfall that would be provided by electricity consumers. We believe that the correct approach is to sell the emissions allowances to parties who hold allocation rights at a preset, administratively-determined rate. A well-determined price for the allowances will prevent the allocation-rights holders from realizing a windfall, and will ensure that the value of the emissions allowances can be applied to the benefit of energy consumers. We further believe that a secondary market for allowances should be allowed to develop that will serve to arbitrage their value based on constantly changing market conditions.

Selling allowances, rather than distributing them free-of-charge, not only follows the well-established principle that public commodities should not be handed out for free, it also addresses the concern that there might be a need to provide for some amount of price stabilization for emissions allowances, at least in the early stages of the AB 32 program. Selling a significant block of allowances at an administratively-determined price would go a long way towards providing market-price stability for these commodities. Moreover, assuming that the mix of administrative allocation and auction is weighted towards the former in the beginning of the program, then gradually adjusted towards the auction option over time, the use of allowance sales in conjunction with administrative allocations would also be gradually phased out, as the market matures, and price stabilization becomes less of a concern.

In making our proposal for combining administrative allocations of greenhouse-gas emissions allowances with distribution of the allowances to the allocation-rights holders by sales at a preset, administratively-determined price, the GPI is not suggesting that we consider this option to be preferable to allocation and distribution by auction. We see a role for the use of both methods of allocation as the newly-created market for emissions allowances is established. What we are suggesting is that in all cases where administrative allocation is determined to be the method of choice for some or all of the allowances, the allocation should be of purchasing rights for the allowances, and the revenues raised through the allowance sales, like the revenues raised via auctions, should be used to invest in new, zero-emitting generating options and efficiency, in order to benefit consumers by providing the infrastructure needed for living in a carbon-constrained world (see discussion below on the use of revenues from emissions allowance sales and auctions, Section III. B. 4. Use of Revenues Collected from the Distribution of Allowances).

In the opinion of the GPI, the proper approach for distributing greenhouse-gas emissions allowances, when administrative allocation is the method of choice, is to administratively allocate rights to **purchase** emissions allowances at a pre-determined, administratively-set price. The administrative allocation to generators of purchasing rights for greenhouse-gas emissions allowances can be done using the same methods as discussed in the Staff Paper for the administrative allocation of free allowances. The two competing models are allocation based on historical emissions (emissions based), and allocation based on electricity production (output based). These two approaches will have different effects on the behavior of market participants, regardless of whether the allowances are distributed without charge, or are sold at an administratively-determined price. The economic implications of our proposed greenhouse-gas emissions allowance allocation and distribution method is analyzed in conjunction with our analysis of the economic implications of the other emissions-allowance allocation and distribution options considered in the Staff Paper, in Section III. B. of these *Comments*.

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

The Staff Paper considers three "pure" allocation and distribution options for greenhouse-gas emissions allowances, and modifications to each of the three options that attempt to correct or improve on the "pure" version of the option. The record of the proceeding contains not only the Staff Paper, but many of the source materials on which it relies. In the opinion of the GPI, a common weakness in both the source materials and the Staff Paper is their over reliance on theoretical economic constructs, such as perfect markets, and market participants acting with perfect information and exclusively profit-maximizing behavior. Theoretical economic analysis of perfect markets provides valuable insights, which certainly should be considered in formulating the joint Commissions' next set of recommendations to the ARB for the implementation of AB 32. However, in the real world markets are not perfect, and market participants do not always display the tendencies predicted by economic theory. This, too, must be considered in formulating the joint PUC / CEC recommendations. In the opinion of the GPI, rigid application of theoretical economics to the process of deregulation, without due consideration of market imperfections, was a key contributor to the California electricity-sector meltdown of 2000 – 2001. It is extremely important to avoid letting that happen in conjunction with the design of a greenhouse-gas reduction system.

Question no. 9 on page 7 of the April 16, ALJ's *Ruling* asks parties to comment on the economic-efficiency aspects of various emissions-allowance allocation options that have been entered into the record of this proceeding. The Staff Paper on allowance-allocation options does not include economic efficiency among the evaluation criteria it uses to judge among allocation options, on the theory that allocation is about distributing costs and benefits, and does not affect the magnitude of the cost:

> Similarly, the requirement that the design achieves the maximum feasible, cost-effective reductions at lowest cost to California is one reason for recommending a market-based mechanism, but allocation is primarily an issue of distribution of the resulting costs and benefits among different sectors of society, not the total cost to society. We recognize that AB 32 requires achieving real GHG reductions, which is the focus of all of our efforts. However,

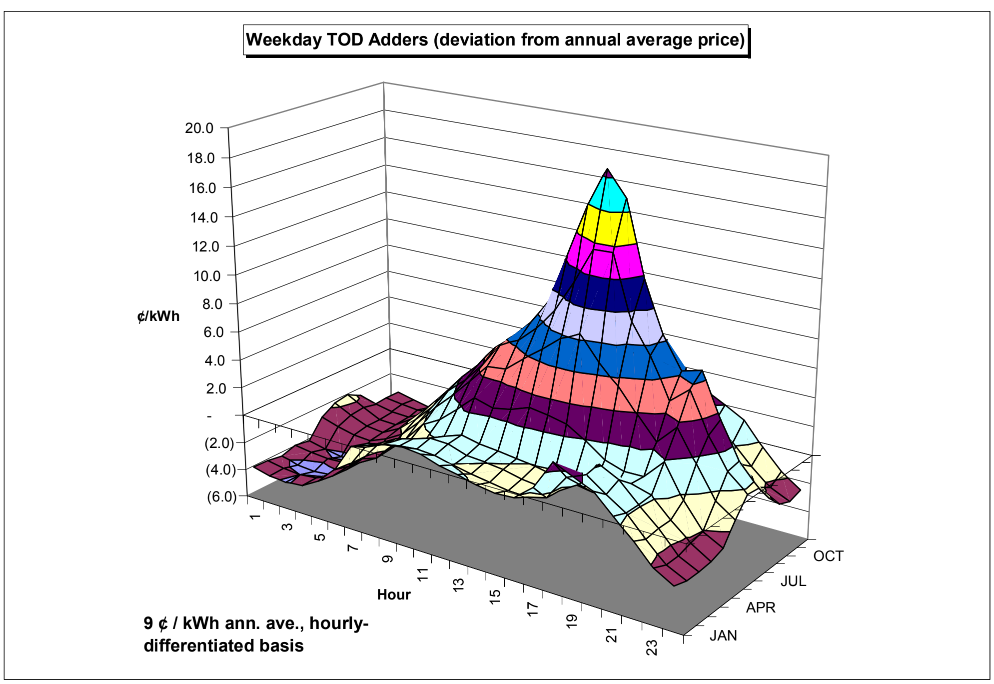
> that requirement does not help us distinguish among allocation options; it is chiefly a function of how the declining cap is set for the cap-and-trade system as a whole (Staff Paper, page 10).

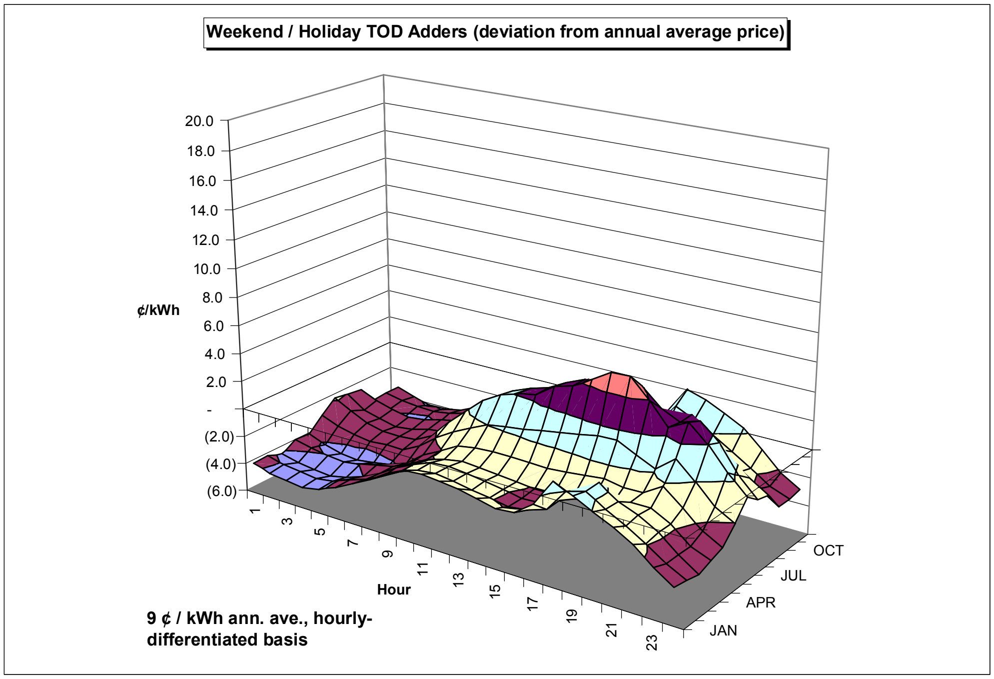
We respectfully disagree. We believe that economic efficiency should be a key criterion in judging among emissions-allowance allocation and distribution options. The emissions allowances that will be created in conjunction with the cap-and-trade system described in D.08-03-018 will be valuable commodities, particularly as their supply is ratcheted downward. Various options for how these allowances are allocated and distributed will affect different market participants in different ways. Indeed, these issues are discussed in the Staff Paper, and in some of the attachments to the various *Rulings* requesting this set of comments on allocation and related issues in this proceeding. For example, the Staff Paper is concerned that the pure output-based allocation mechanism would provide incentives for greater electricity consumption, concluding: "By incentivizing a higher level of consumption, these lower prices come at the expense of total economic efficiency (Staff Paper, pg. 27)." This statement notwithstanding, economic efficiency is not included in the set of evaluation criterion adopted by the Staff Paper. This deficiency should be corrected.

The GPI believes that the joint Commissions need to go beyond theoretical economic analysis in considering the economic-efficiency aspects of the various allocation and distribution options, and consider the differential incentives that the various options may provide for the exercise of market power, and for other manipulative market behaviors, such as hording. In addition, if the cap-and-trade system is initially implemented only in California, it is important to consider what kinds of differential incentives are created by the various options for source shuffling throughout the West.

The E3 greenhouse gas calculator attempts to calculate system-wide greenhouse-gas emissions and costs in the Western Interconnect for a variety of future energy-system scenarios and control measures. To supplement the record, we have conducted a micro-level analysis of the likely behavior of generators under the various emissions-allowance allocation and distribution options under consideration in this proceeding. We focus on generators, as they are both the point of regulation under the cap-and-trade system adopted in D.08-03-018, as well as the immediate source of the greenhouse-gas emissions associated with the electricity sector. We believe that administrative allocations to retail providers under a deliverer-based system are simply inappropriate.

For purposes of this analysis, we have constructed a model that predicts the annual operating behavior for a generator, based on the generator's native variable operating cost, the time-adjusted value of electricity (all-in, including capacity), and the cost, if any, of required greenhouse-gas emissions allowances. The analysis is performed for revenues that are time-differentiated on an hourly basis, with separate monthly profiles for weekdays, and for weekends and holidays. The hourly-price profiles, which are derived from California utility load profiles and electricity supply curves, are used to determine optimal operating profiles for fossil-fired generators, based on their variable cost of generation, and the cost of required emissions allowances, if any. The model also determines the marginal revenue level at which the generator chooses to generate. The time-differentiated price profiles used for the analysis described herein, which are based on Northern California data, are illustrated below.





For analytical purposes we have taken data, where available, from the E3 greenhouse gas calculator. The calculator's variable operating costs for coal-fired and natural-gas-fired electricity are \$31.5 per MWh, and \$70 per MWh respectively. Coal generators will require approximately 1.25 emissions allowances[2] per MWh, while natural-gas generators will require approximately 0.45 allowances per MWh. We assume a base-case annual average all-in electricity value of \$90 per MWh (9 ¢ per kWh), which is consistent with current market conditions, as well as the current MPR, and the E3 model's database.

Under pre-AB 32 conditions, a coal-fired power plant selling power at hourly-differentiated rates would operate with an annual capacity factor of 91 percent, limited only by the need for an annual maintenance shutdown, and unscheduled outages (variable cost < revenue during all hours of the year). A CCGT selling power at hourly-differentiated rates would operate with a capacity factor of 65 percent,[3] operating only

[2] One emissions allowance excuses emissions of one ton of CO_2 equivalents.
[3] In the real world, power plants cannot be turned on and off instantly and constantly, as is implicitly assumed in the model. As a result, the model probably underestimates the capacity factor that a real generator will achieve, operating under the same revenue-value profiles as employed in the model. For example, most CCGTs today operate at capacity factors of 65 – 75 percent, while the model calculates the optimal capacity factor as 65 percent.

when revenues exceed variable operating costs, and taking into account scheduled and unscheduled outages. For reference purposes, the analysis is conducted under two conditions, a ten-percent reduction in emissions for fossil-fuel generators, and with emissions allowance values of $30 per allowance, which is consistent with the base case in the E3 greenhouse-gas calculator.

We acknowledge that in the real-world marketplace generators do not always see hourly price signals. Many wholesale energy transactions are done on the basis of large blocks of power, for example peak and off-peak on a daily or monthly basis, or in the case of QF and RPS contracts, rate differentiation into 6 – 9 annual TOD blocks. Some power sales agreements are not time-differentiated at all. Generators operating under these kinds of pricing terms are not likely to operate in the optimal pattern predicted by the model. On the other hand, the establishment of an hourly market for power in the state under the CAISO's MRTU would be expected to push generators towards the kind of operating behavior based on hourly-variable rates that is assumed in the model.

III. B. 1. Allocation Based on Emissions

A standard technique in environmental cap-and-trade markets is to allocate emissions allowances to emitters on the basis of a given percentage of the emitter's historical baseline of emissions. The AB 32 program aims to return California to its 1990 level of total greenhouse-gas emissions by 2020, which means cutting current statewide emissions levels by about ten percent. While acknowledging that AB 32 does not set inter-sectoral emissions targets, for analytical purposes we base our analysis on achieving a ten-percent reduction from current emissions levels in the state's electricity sector.

Under the base-case assumption set defined for this analysis, the lowest hourly revenue level for the year is 4.3 ¢/kWh (9.0 ¢/kWh annual-average basis), which is greater than the variable operating cost for coal (3.15 ¢/kWh), but less than the variable operating cost for CCGTs (7.00 ¢/kWh). As a result, in the current marketplace coal generators operate at a capacity factor that is limited only by equipment needs (91%), while CCGTs operate at a capacity factor that is limited by both equipment needs and price considerations (65%).

In the Staff Paper's "pure" emissions-based allocation option, coal and gas-fired generators would be presented with a sufficient quantity of emissions allowances to allow them to operate at approximately 90 percent of their baseline levels in 2020. Coal generators would thus be able to operate at a capacity factor of 82 percent with their free allocation, while gas generators would be able to operate at a capacity factor of 58.5 percent. Assuming that both types of generators were to reduce their annual output to their allocated levels by eliminating generation during the lowest-valued hours of the year, coal generators would continue to generate to a low revenue level of 5.4 ¢/kWh (eliminating generation when revenues are between 4.3 – 5.4 ¢/kWh), and gas generators would continue to generate to a low revenue level of 7.6 ¢/kWh (eliminating generation when revenues are between 7.0 – 7.6 ¢/kWh). Because the generators receive their allowances at no cost, and are able to arrange to curtail their operations during periods when their net operating margins are at their lowest, they suffer minimal economic loss.

At the ten-percent output-reduction level coal generators have a marginal operating margin (revenue less variable operating cost) of 2.25 ¢/kWh (5.5 – 3.15), which would allow them to pay up to $ 17.60 per emissions allowance in order to increase their annual output beyond the level imposed by their initial allocation of allowances. At ten-percent reduction, gas generators have a marginal operating margin of 0.6 ¢/kWh, which would allow them to pay up to $ 13.10 per emissions allowance in order to increase their annual output. As a result, using the base-case assumption set and a mandated ten percent greenhouse-gas reduction level, at their respective operating margins coal generators would be likely to purchase a limited quantity of emissions allowances from gas generators, which would have the unintended consequence of diminishing the amount of electricity available in the marketplace from fossil-fuel generators, given a fixed overall supply of emissions allowances.

As the overall quantity of emissions allowances is ratcheted down, and fossil generators face having to reduce operations during hours of increasingly profitable operating hours, the advantage that gas generators have in terms of fewer allowances needed per MWh overtakes the advantage that coal generators have in terms of lower native variable operating costs. For example, if generators were allocated enough free emissions allowances to permit operations at 80 percent of baseline, coal generators would have a marginal operating margin of 2.9 ¢/kWh, which would allow them to pay up to $ 23.60 for additional allowances, while gas generators would have a marginal operating margin of 1.2 ¢/kWh, which would allow them to pay up to $ 27.00 for additional allowances. Under these circumstances, coal generators would be likely to sell some of their allowances to gas generators. The crossover occurs at a reduction level from baseline of approximately 15 percent, where, using the base-case assumption set, both gas and coal generators have a marginal value of $20.70 per allowance for acquiring additional allowances.

In *Section III. A.* of these *Comments*, the GPI presents a proposal to distribute greenhouse gas emissions allowances that are administratively allocated by sales to allocation-rights holders at a pre-set, administratively-determined price. Using the "pure" emissions-based allocation system described in the Staff Paper, under the GPI proposal emitters would receive purchasing rights to a sufficient quantity of allowances to permit operations at 90 percent of their baseline levels. As the discussion of the free-distribution option demonstrated, at the 90 percent operating level coal generators confer a marginal value of $17.60 to allowances, while gas generators confer a marginal value to allowances of $13.10. If the allowance price were set at levels in excess of these values, generators would be expected to decline to purchase their entire allocations. The following table shows the percentage of baseline allowances that a generator would be willing to purchase at various greenhouse-gas emissions allowance-price levels.

$/allow.	Coal %baseline	Gas %baseline
0	100%	100%
10	100%	92%
15	95%	88%
20	86%	85%
30	70%	77%

If generators were given purchasing rights to allowances to permit operations at 90 percent of baseline, and allowances were priced at $10, then both coal and gas generators would purchase their entire allocation of allowances. Moreover, both kinds of generators would be willing to purchase additional allowances, coal for a marginal value of $17.60, and gas for $13.10. Under these circumstances coal generators would tend to purchase some allowances from gas generators, the same as in the case discussed previously of free distribution of allowances using the "pure" emissions-based allocation system.

With purchasing rights to 90 percent of baseline, and allowances priced at $20, under base-case assumptions coal generators would only purchase enough allowances to operate at 86 percent of baseline, and gas generators enough to operate 85 percent of baseline. The unsold allowances could then be auctioned, where they would be expected to fetch a value lower than the $20 level. By pricing the allowances at a higher level than the market-clearing price (MCP) that is needed to achieve a ten-percent reduction in emissions, rather than below this level, the program would encumber fossil generators with greater overall costs, and thus would put greater pressure on overall market prices. This could be a benefit in terms of promoting the rapid development of zero-carbon alternatives. However, pushing the price of allocated allowances too high relative to the MCP will cause generators to decline to purchase any of their allowances from their allocations, preferring instead to let them all fall into the auction pool.

It is instructive to consider the effect that an overall market-based price adjustment would have for the generators considered above. The generator-based model developed by the GPI cannot predict overall economic impacts. The E3 calculator, which is a macroeconomic model, is designed to calculate overall market price effects, among other parameters. For analytical purposes, assume that as a result of the imposition of an overall ten-percent greenhouse-gas emissions reduction on the electricity sector, the overall wholesale market price of electricity were to increase by 0.5 – 1.0 ¢/kWh. In this case the marginal value to generators for allowances would increase accordingly. For coal generators the marginal value, which was $17.60 per allowance at an overall market price of 9 ¢/kWh, increases to $21.60 @ 9.5 ¢/kWh, and $25.60 @ 10.0 ¢/kWh. For gas generators the marginal value, which was $13.10 per allowance with an overall market price of 9 ¢/kWh, increases to $24.20 @ 9.5 ¢/kWh, and $35.30 @ 10.0 ¢/kWh. The result is that the overall market-price increase confers a greater value to allowances for gas generators than for coal generators at the ten percent emissions-reduction level, and therefore instead of coal generators tending to buy allowances from gas generators, the transactions are in the other direction.

The difference between using the "pure" emissions-based allocation system with free distribution, vs. distribution of the allocated allowances by sales, is not so much in how it affects the modeled operating behavior of fossil generators. The difference is on a more macro-economic basis. In the free-distribution option individual generators, by trimming operations when the operating margin is thin, will see little effect on their bottom lines, even if market prices were to remain constant. On the other hand, if the allocated allowances are sold rather than distributed free of charge, then the generators will see their profitability drop during all of their permitted operating hours of the year, a significant effect on their bottom lines.

With the free-distribution system, there will be minimal pressure for fossil generators to push up the overall wholesale market price of their electricity, since their own bottom lines are minimally affected. The only market-wide impact, therefore, will be the result of the difference that will have to be paid for the diminished amount of fossil power in the marketplace, and whatever is used to make it up. With the distribution-by-sales option, there will be greater pressure for fossil generators to push up the overall price of electricity, since in this case their bottom lines are indeed affected. In this case the market will also have to make up the allowance-eliminated power, but the price increase demanded by fossil generators will be enough to cover some or all of the cost of the makeup power. Under perfect market conditions the overall market price increase that results from a ten-percent reduction in greenhouse-gas emissions allowances should be same for both allowance-distribution options. In the case of the free-distribution alternative the fossil generators, who do not see a significant change in their operating margin, pocket nearly all of the value of the increase in market price. If the allowances are sold to allocation holders, most of the value of the increase in market price that is borne by consumers is collected in the form of allowance sales revenues, which can be applied to the benefit of those consumers, and generators' bottom lines are approximately the same as before the imposition of regulation (increased market price offsets the cost of allowances).

In looking beyond theoretical, idealized economics, we believe that distribution of allowances by sales rather than without charge provides some important market protections and benefits. By having to pay an amount approximating the MCP for allowances, market participants who receive allowance allocations will be far less likely to exhibit manipulative or hording behavior. In addition, by imposing greater operating costs directly on fossil generators, the program will ensure that the inevitable pressure on the market price of electricity comes from the fossil-fuel segment of the supply market. In the free-distribution approach, this large and influential segment of the market will have little impetus to be the catalyst for higher market prices. The result will be that it will fall to the carbon-free alternatives that will have to fill-in for the permit-eliminated fossil power to do the pushing for increased market prices, and they have far less market power than fossil generators. In this case, there is a much greater probability that AB 32 program safety valves will be invoked, and that AB 32 targets will fail to be met.

As consumer and environmental advocates, the GPI does not wish to leave the impression that we believe that higher overall market prices for electricity are in some sense a virtue, or even desirable. We simply accept the inevitability that achieving the goals of AB 32 will come at a cost, and that cost ultimately will be expressed as an increase in the price of electricity. If, in fact, the alternatives to fossil power were cheaper than fossil power, then they would already be utilized, and there would be no need for an AB 32. The corollary to the postulate that achieving AB 32 goals inevitably will increase the cost of electricity, is that holding the line on the price of electricity is not compatible with achieving the goals of AB 32. This is the basis for our concern that if there is insufficient pressure on electricity prices coming from the fossil sector, and all of the pressure is perceived to be coming from the renewables and efficiency sectors, then the likelihood of safety valves being invoked and the goals of AB 32 not being achieved are greatly increased.

III. B. 2. Allocation Based on Output

The "pure" output-based allocation system described in the Staff Paper would provide fossil generators shorter allocations than they would receive in an emissions-based allocation system with the same overall supply of allowances. Using data from the E3 model, it is estimated that under the "pure" output-based allocation mechanism generators would be allocated approximately 0.33 allowances per MWh of output (~300,000 GWh/yr of electricity consumption, ~100 million tons of emissions). At that allocation level, gas generators would be able to operate at 73 percent of their baseline level, while coal generators would be able to operate at only 22 percent of baseline. The "pure" output-based system puts a large quantity of allowances in the hands of emissions-free generators that do not need them, giving these generators the ability to sell their unneeded allowances to fossil generators, all of whom are short.

A variant of this system, favored by the Staff Report, would allocate allowances only to fossil-fired generators, in accordance with their respective MWh outputs. In this variant the allocation to fossil generators would increase to approximately 0.6 allowances per kWh. Gas generators would receive 33 percent more allowances than they need in order to operate at baseline levels, while coal generators would receive enough allowances to operate at 40 percent of their baseline levels. In this situation gas generators would be expected to sell surplus allowances to coal generators. If the imposition of the AB 32 compliance program serves to increase overall market prices, under this allocation mechanism gas generators might very well generate at greater annual capacity factors than under current (no carbon constraints) market conditions, with a corresponding drop in coal generation levels.

The idealized economics for an output-based allocation alternative, from a generator perspective, are essentially the same as discussed above for the emissions-based allocation alternative. At the ten-percent reduction level for electricity-sector emissions, applied to each generator and using the base-case study assumption set, the MCP for allowances will be approximately $15 (13.1 for gas, 17.6 for coal). If the overall market price for electricity increases to 9.5 ¢/kWh as a result of the programmatically-imposed emissions-reduction program, the MCP will be approximately $23 per allowance, and if it increases to 10.0 ¢/kWh, the MCP will be more than $30 per allowance.

If a free distribution system is used with an output-based allocation system for greenhouse-gas emissions allowances, many of the same risks will be encountered as with emissions-based allocations with free distribution of allowances. These include windfall profits for fossil generators, in this case skewed in favor of gas generators over coal generators as compared with emissions-based allocations, and the temptation for speculation and manipulation with allowances that are received at no cost by the allocation holders. Indeed, the temptation might be exacerbated in the output-based-to-fossil-generators-only option, in which one group of generators, natural gas, would be supplied with a surplus of allowances compared to their needs, and one group, coal, would be short.

In the "pure" output based system only non-fossil generators, who have no internal need for the use of allowances, would be given surplus allocations. This is significant because the allowances have no intrinsic value to these generators, who could convert them into value only by selling them to those for whom the allowances do have a value. Indeed, part of the rationale for this allocation option is that it would enable the zero-emitting resources like renewables to improve their economic performance, and thereby expand their contribution to the state's supply mix. Output-based allocation to only fossil generators, with free distribution of the allowances to the allocation holders, enhances the profitability of gas-fired generation at the expense of coal generation, while providing little in the way of redeeming benefit to the marketplace.

Sales of the greenhouse-gas emissions allowances to allocation-rights holders will ameliorate many of the shortcomings of free distribution, by transferring the value of the allocations from generators (renewables or gas, depending on whether the allocation is to all generators, or only fossil generators), to a fund that, in the opinion of the GPI, should be made available for application to the public benefit. Selling the allowances removes the temptation for speculation, and puts the burden and responsibility for establishing higher market-energy prices directly on fossil generators, rather than on zero-carbon generators like renewables and efficiency.

III. B. 3. Allocation Based on Auction

Auctioning greenhouse-gas emissions allowances, rather than allocating them administratively with sales to the allocation-rights holders, would be expected to zero-in directly on the MCP for allowances for any given overall supply of allowances. In administrative allocations of purchase rights to allowances the MCP would be more likely to be achieved in the secondary market for emissions allowances, although with diligence and experience the issuing authorities ought to be able to set a price for sales to emissions-allocation-rights holders that is reasonably close to the MCP.

Like the administrative-allocation-of-purchase-rights option, auction of allowances mitigates against market manipulation and the exercise of market power, and puts more of the burden and responsibility for the inevitable rise in overall energy prices due to mandated reductions in greenhouse-gas emissions on the fossil generation sector, rather than on the renewables and efficiency sectors. Auctions of emissions allowances do a better job than administrative allocations over the long term of accommodating new market entrants, and promoting technological development. Administrative allocations, on the other hand, provide a higher degree of certainty and stability in the short term while a brand-new program and commodity marketplace is still being conceptualized, designed, and implemented.

The GPI supports the approach of initiating a cap-and-trade program for greenhouse-gas emissions allowances based primarily on administrative allocation of the allowances, with a small fraction of the allowances auctioned, transitioning to increasing reliance on auctions as the market develops, matures, and stabilizes. In order to apply the inevitable increase in consumer costs to the benefit of the consumers, as well as to promote the overall chances for the achievement of AB 32 goals, we recommend that administrative allocations of allowances be of purchase rights to allowances, rather than distributing the administratively-allocated allowances without charge to the allocation holders. Doing so not only avoids windfall profits and mitigates against marketplace abuses, it also will serve to ease the transition to an increasing reliance on allocation by auction, by conditioning generators to paying for their emissions allowances from the start.

The analysis presented above is based on the application of ideal, theoretical economics. In fact, in the real world markets do not act perfectly, and market participants do not always act in their own, idealized best interests. In addition to considering the insights provided by this analysis, it is important to consider how real-world considerations affect these insights. For example, in the real-world marketplace not all generators in a particular category have the same variable cost of operations, and not all generators operate with identical revenue-value profiles. As a result, there is no bright-line value for the MCP for emissions allowances under any given market configuration, but rather a range of values.

The theoretical analysis ignores the transaction costs that are an unavoidable component of real markets. Any program that involves the creation and retirement of emissions allowances requires an entity to administer the creation, allocation, distribution, tracking, and retirement of the allowances, as well as to ensure that all emissions that are subject to the allowances are accounted for, and nothing falls through the cracks. One obvious option for funding the administrative costs of the system is to charge market participants a fee for transactions involving emissions allowances. While it is our expectation that the transaction costs will be a small fraction of the value of the allowances, it is a fact that transaction costs discourage market transactions, and tend to hinder the "ideal" functioning of the marketplace.

In comparing the various alternatives for the allocation and distribution of greenhouse-gas emissions allowances in a cap-and-trade program, we believe that a number of observations can be made. Within the spectrum of options under consideration, the "pure" emissions-based allocation method would put the greatest number of allowances directly into the hands of the generators that are likely to use them, while the "pure" output-based allocation method would put a substantial number of allowances into the hands of entities that have no internal need for them. Relatively little trading of allowances would be required to reach market equilibrium in the emissions-based allocation approach, while a large volume of trading would be required in the output-based allocation approach.

The greater the extent to which fossil generators are given free allocations of their requirements for emissions allowances, the less these generators will see changes in their total costs of operations, or in their annual operating margins. This has potential negative consequences for the development of a carbon marketplace. Fossil generators under these circumstances will not be the market segment that will exert significant upward pressure on the market price of energy, leaving that job to others, like the renewables and efficiency that are needed to fill-in the gaps as fossil generation is ratcheted down. Under these circumstances any increase in overall market-energy prices that does occurs as a result of AB 32 regulations will be blamed on the clean alternatives, while simultaneously translating into pure profits for the fossil generators. This is a certain recipe for failure to accomplish the goals of AB 32.

The "pure" output-based allocation option requires fossil generators to purchase a greater percentage of their allowances for any given annual output level than the emissions-based option, which means that with the output-based option fossil generators will see their own variable costs increase more, and their operating margins shrink to a greater extent. This will send them to the marketplace in search of higher overall prices, and will limit the profits they realize from their allocations of free allowances. We note that the Staff Paper's preferred emissions-based allocation approach, which entails auctioning a portion of the total allowance supply, accomplishes some of the same improvements over the "pure" emissions-based approach, by reducing the proportion of allowances that the fossil generators receive at no cost.

The GPI assumes that with a new carbon market starting up in 2012 in California, the majority of the emissions allowances issued during the initial years of the program will be administratively allocated, rather than auctioned. If the administratively-allocated allowances are distributed free of charge, the GPI believes that the "pure" output-based allocation mechanism would be preferable to both output-based allocation to fossil generators only, or emissions-based allocation, based on macroeconomic effects. The "pure" output-based system puts the fewest free allowances in the hands of the fossil generators, thus making them purchase more of their requirements in the marketplace. In addition, zero-emitting generators, whose native cost of generation is typically greater than that of fossil generators, are able to enhance their operating profitability by selling the allowances they are allocated. This will facilitate their entry into the commercial marketplace.

If the GPI's proposal for sales of administratively-allocated emissions allowances is adopted, then we believe that the preferred allocation method for the allowances is the emissions-based mechanism. Sales of emissions allowances to purchase-rights holders removes the potential for unproductive funds transfers from consumers to generators, and properly puts the onus for driving market-price adjustments on the fossil-fuel segment of the energy-supply infrastructure. That being the case, emissions-based allocation minimizes the volume of allowance transfers that must take place in order to bring the market to equilibrium, and provides more equitable treatment between coal and natural-gas generators. On the other hand, it can be argued that the more generous treatment given gas generators over coal generators in an output-based allocation may serve to hasten the decline in carbon-intensive, coal-fired generation as a viable supply source for California (new coal generation for California is already precluded by state's Emissions Performance Standard enacted in 2007).

III. B. 4. Use of Revenues Collected from the Distribution of Allowances

Question nos. 10 – 13 on pages 7 and 8 of the April 16, 2008, ALJ's *Ruling* ask parties to comment on the use of revenues raised through the sale of greenhouse-gas emissions allowances to purchase-rights holders and auction winners. In the opinion of the GPI, the revenues raised through the distribution of greenhouse-gas emissions allowances should be used to invest in new, zero-emitting generating resources and efficiency, in order to benefit consumers by providing the infrastructure needed for living in a carbon-constrained world. Using the allowance-sales revenues to try to maintain affordable rates for consumers not only fails to provide an enduring value to the consumer from the funds that the consumers themselves will provide via increased energy prices; it also serves to dampen the price signals that are necessary to elicit desirable market responses. The best way to benefit consumers is to invest the funds raised by sales of greenhouse gas allowances in the infrastructure that ultimately is needed in the state in order to comply with AB 32.

IV. Flexible Compliance

The GPI believes that whatever AB 32 compliance program is eventually put into place, it should include a sufficient level of flexibility to reward early actions and efforts to get ahead of the curve, as well as to allow obligated entities the ability to fall behind in their requirements, to a limited extent, in order to supply power needed during shortfalls, while ensuring that they do not fall so far behind that they can never make it up. We believe that the flexible compliance regime that has been fashioned for the RPS program provides a useful model for the flexible compliance program that will be needed for the AB 32 compliance program.

IV. B. Scope of Market and Related Issues

Question no. 4 on page 4 of the May 28, 2008, ALJ's *Ruling* on flexible compliance asks whether it is appropriate to recommend flexible compliance rules at the present time, when the market itself has not yet been designed. The GPI believes that this is a profound question, worthy of serious consideration. AB 32, and the additional measures to control greenhouse gases that are certain to follow, will not be easy to implement. One key to the success of the program will be the design of a compliance system that is both flexible enough to promote technological innovation and economic efficiency, and enforceable enough to motivate regulated entities to fully comply with their regulatory obligations.

The entire suite of compliance and enforcement measures has to work together, and achieve a delicate balance.

We believe that appropriateness of employing many of the flexible compliance tools discussed in the ALJ's *Ruling* is dependent on the basic compliance system itself, as well as on the suite of other flexible-compliance tools that are employed. For example, the need for banking and borrowing provisions for emissions allowances is intricately related to the length of the compliance period that is adopted. The longer the compliance period is, the less the need for banking and borrowing. Similarly price triggers, safety valves, and penalties or alternative compliance payments are interrelated mechanisms, and should not be designed into the system independently of each other. The entire compliance system has to be flexible but effective in order for the state to have any chance of achieving the goals of the statute, which are ambitious and challenging. In our opinion it is useful to consider a range of possible flexible-compliance options when establishing the essential specifications of the basic compliance system, but the flexible components should not be decided upon until the market itself has been designed. We believe that it is particularly important in order to make sure that the system does not become so flexible that compliance never has to be achieved.

IV. D. Linkage

Decision D.08-03-018 determined that the joint Commissions (PUC & CEC) would recommend to the ARB the establishment of a limited cap-and-trade program for greenhouse-gas emissions allowances in California that would be ready to function in 2012, when statewide AB 32 compliance obligations first go into effect. In the beginning, it is anticipated that the limited cap-and-trade market would cover the state's electricity sector, and possibly the transportation sector, but not the natural gas sector. In the longer term the Decision expects the market-based program to expand to include more sectors, and greater geographic scope (regional, national, and eventually international). Over time, we expect that some of the questions asked in the May 6, 2008, *ALJ's Ruling*, in Sections **2.4 Linkage**, and **2.8 Offsets,** will become moot, as the programmatic reach of the California greenhouse-gas reduction program expands.

From a scientific perspective, the geographical location of greenhouse-gas emissions is of no significance to their ultimate contribution to global climate change. The atmosphere is well mixed with respect to the major climate-forcing gases, CO_2 and CH_4, which have atmospheric residence times numbering in the tens or hundreds of years. This is in contrast to the case for many of the conventionally regulated pollutants, like SOx and NOx, whose negative consequences are regional in scope, but not national or international. Thus, if the only consideration is limiting greenhouse-gas emissions, there is no valid rationale for placing geographic limitations on where the permitted emissions or validated offset reductions take place.

There is no doubt that the fundamental goal of AB 32 is to limit greenhouse-gas emissions. However, that does not mean that greenhouse-gas emissions reduction is the only goal of the program. As innovators, Californians will be investing a significant amount of money into a program that we know very well will work only if it spreads well beyond California. In our opinion, it is a legitimate interest for the state to try to take advantage, to the maximum extent possible, of the economic activity that will be stimulated by AB 32, keeping in mind that in many cases overall cost containment can be facilitated by trade, and by extra-regional activities. In the opinion of the GPI, California's AB 32 program should promote compliance activities that take place in California, for example with incentives of various kinds, but should neither prohibit, nor discount, compliance activities that take place outside of the state or country. Some limits on out-of-state compliance contributions probably makes sense, especially in the beginning of the program when the rules are being road tested, and confidence in the verifiability of out-of-state allowances, certificates, and offsets has not yet been established.

The GPI's overall approach with respect to linkage to other programs is that in almost every respect, merging programs is better than linking. Nevertheless, it is reasonable to set general principles for linkage, when linkage is under consideration. We believe that the general principles that WREGIS has established for linkage with other renewables-tracking systems are applicable here. Linkage should require a formal agreement between the authorities who oversee the programs being linked, and the linkages should always be bilateral. Whatever minimum criteria are established in California for qualifying emissions allowances or other AB 32 compliance-program instruments, those criteria should be guaranteed by the program linking to the California program, just as California should reciprocally guarantee any allowances or certificates that are transferred to the linked system. Mutual enforcement of consistent standards not only guarantees the integrity of transfers between systems, it also facilitates the ultimate combining of programs.

IV. H. Offsets

Many of the same considerations pertaining to linkage, also pertain to offsets. Offsets that are verifiable and additional to other programs and requirements, whether generated inside or outside of California, should be honored in California's greenhouse-gas emissions control program. It is reasonable to consider setting limits on the use of offsets that are generated outside of the state, just as it is reasonable to consider limits on the use of allowances from out-of-state linked programs. We do not see any valid reason for placing limitations on the use of legitimate, qualified offsets that are generated within the state of California.

The GPI is particularly interested in seeing the ground rules established in California's AB 32 compliance program for providing offsets for reductions in emissions of biogenic greenhouse-gas emissions associated with the production of energy from biomass and biogas resources. A recent Pacific Institute / Green Power Institute report[4] demonstrates that the magnitude of the net reduction in biogenic greenhouse-gas emissions associated with bioenergy production in California is equal to or greater than the fossil-fuel greenhouse-gas emissions that are avoided.

Biogas generators, for example, collect the off-gas from biomass decomposition (e.g. landfill gas or digester gas from manure-treatment lagoons), and covert the roughly 50 percent of the gas that is CH_4 into CO_2. CH_4 is a far more potent greenhouse gas than CO_2, so the energy production process simultaneously reduces the effective greenhouse-

[4] Morris, Gregory, *Bioenergy and Greenhouse Gases*, Report of the Green Power Institute, the renewable energy program of the Pacific Institute, Oakland, CA, May, 2008.

gas effectiveness of the biogas. In cases where the collection and destruction of the biogas is already required by regulation, the generators should only be given credit for the reductions, if any, that go beyond the regulatory requirements. In cases where the biogas is not regulated, then the generator should be able to claim full credit for the reduction. All bioenergy-generated offsets for reductions in biogenic greenhouse-gas emissions should be counted net of the emissions of the energy production process (stack emissions), in order to ensure that the renewable energy is delivered greenhouse-gas free, like other forms of renewable energy. This is already a requirement in the RPS program.

Biomass generators, in addition to avoiding fossil generation, reduce the biogenic greenhouse-gas burden associated with the alternative disposal or disposition of the residues that are used as biomass fuels. For example, biomass generation keeps biomass residues out of landfills, and out of open-burn piles in agricultural and forestry regions of California. Open burning of agricultural and forest-residue biomass is not only a major source of conventional air pollution in the state, it also produces much greater quantities of uncombusted gases than the controlled boilers used in power plants. From a greenhouse-gas perspective, this is equivalent to emitting significant quantities of CH_4 in place of CO_2 during the combustion process.

Biomass power generation also promotes healthy California forests by underwriting some of the cost of forest treatment operations by providing a productive-use outlet for the treatment residues. Although the immediate result, from a greenhouse gas perspective, of using forest residues as fuel is to transfer carbon from the forest to the atmosphere, over time treated forests have greater growth rates than overgrown forests, and their improved resistance to damage from fires, disease, and pest outbreaks means that healthy forests sequester more carbon on a long term, sustainable basis than the stressed, overgrown forests that predominate in the state today. The Table reproduced below, which is Table 6, page 41, from the Pacific Institute report referenced previously (footnote no. 4), shows the greenhouse-gas emissions factors for the reduced biogenic greenhouse-gas emissions, and the avoided fossil greenhouse-gas emissions, attributable to biomass and biogas energy generation in California.

Greenhouse Gas Emissions Factors for Biomass and Biogas (all factors expressed as equivalent year-1 emissions of CO_2 equivalents)			
	ton/bdt	ton/bil.btu	ton/MWh
Biomass			
Net Reduction in Biogenic C			
Open Burning	0.62	36	0.62
Forest Accumulation	1.87	110	1.87
Uncontrolled Landfill	2.28	134	2.28
Controlled Landfill	0.27	16	0.27
Spreading	0.69	41	0.69
Composting	1.00	59	1.00
Kiln Boiler / Fireplaces	0.22	13	0.22
California Biomass Mix 2005	0.81	48	0.81
Avoided Fossil Fuel Use	0.80	47	0.80
Landfill Gas (LFG)			
Net Reduction in Biogenic C			
Uncontrolled Landfill		241	2.89
Controlled Landfill		22	0.26
Avoided Fossil Fuel Use		65	0.78
Dairy Manure			
Net Reduction in Biogenic C	2.88	180	8.64
Avoided Fossil Fuel Use	0.26	16	0.78

The table shows that the generation of one MWh of energy from biomass or biogas avoids emissions of approximately 0.8 tons of fossil CO_2. The production of one MWh of electricity from biomass fuels that would otherwise be open burned if they were not used for energy production reduces the biogenic greenhouse-gas emissions associated with the disposal of the biomass by about 0.6 tons of CO_2 equiv. If the alternative fate for the fuel is to be left in the forest as overgrowth material, the biogenic greenhouse-gas emissions reduction is about 1.9 tons of CO_2 equiv. Greenhouse-gas emissions offsets should be created for the demonstrable and verifiable net reductions in biogenic greenhouse-gas emissions associated with biomass energy production. Whether the amount of offsets for a given generator should be set specific to the mix of fuels used by that generator, and their alternative fates, or whether a uniform statewide offset factor should be used, is a matter still to be determined. Bioenergy-related greenhouse-gas offsets that are created in California should be usable without limitation in the state's AB 32 compliance program.

Whatever specifications the California AB 32 compliance program may eventually assume, it will have to be administered by an effective authority. That authority should also be responsible for approving and certifying greenhouse-gas emissions offsets, among its many duties. We recommend that general classes of activities that can produce qualified offsets, such as the use of biomass and biogas fuels, should be pre-qualified for the California compliance program, and specific guidelines should be established for their creation and use. The program should also be open to considering requests for the creation of other types of offsets that might be suggested, and a process for consideration of newly proposed offsets should be established.

VI. Non-Market-Based Emissions Reduction Measures and Emissions Caps

Decision D.08-03-018 in this proceeding expresses the joint Commissions' preference for the creation of a limited cap-and-trade system, as part of the overall effort to regulate greenhouse-gas emissions from the state's electricity sector. The Decision notes, however, that it expects the bulk of the emissions reductions necessary to meet the AB 32 targets to come from the established renewables and efficiency programs, with the cap-and-trade program expected to elicit additional reductions via the market mechanism:

> We agree with several parties, including NRDC/UCS, that the cap-and-trade system need only produce a relatively small portion of the overall emissions reductions in the short term. We recommend that ARB design it as a complement to existing policies and their expansions as noted above. As described above, a large portion of the emissions reductions in the electricity sector will come from mandated investments in energy efficiency and other demand reduction programs, as well as renewable energy goals (D.08-03-018, pg. 39).

The GPI supported that finding in our February 28, 2008, *Comments on the PD*, and we support it here as well. Indeed, when E3 announced, during the April 21 – 22, 2008, workshop on allocation and modeling, their finding that it would take an allowance price in the neighborhood of $150 per allowance to elicit a significant market response, our resolve to support the existing programmatic approach (RPS and EE) to greenhouse-gas emissions reductions was strongly reinforced.

VI. A. Electricity Emission Reduction Measures

The GPI has been a long-time and consistent supporter of extending the RPS to include the stretch goal of 33-percent renewables by 2020, a policy that was adopted by the state's 2005 *Energy Action Plan II*, and even earlier articulated by the Governor. We have advocated for the RPS stretch goal in this proceeding, as well as in the various renewables and general-procurement proceedings at the PUC and CEC. Indeed, recently we took the Commission to task in this proceeding in our February 28, 2008, *Comments on the PD*, for seemingly retreating from the 33-percent-renewables-by-2020 goal. Once again, we urge the joint Commissions to recommend to the ARB that the RPS stretch goal of 33-percent-renewables-by-2020 be included in the AB 32 Scoping Plan.

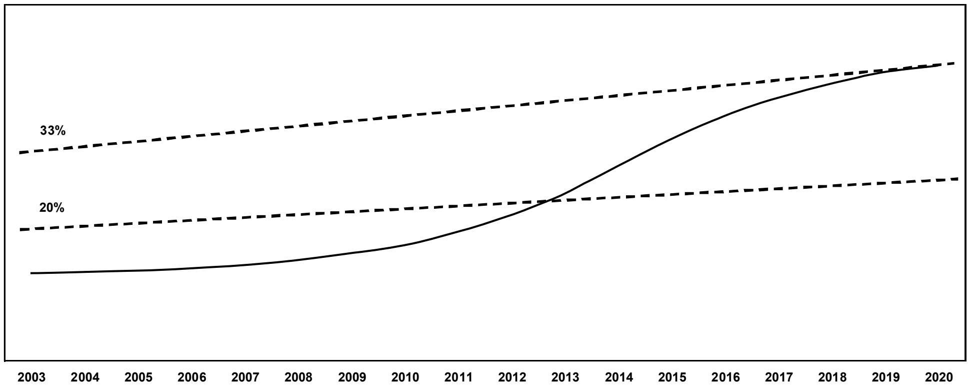
The E3 greenhouse gas calculator demonstrates that current programmatic goals for EE and the RPS by themselves are not sufficient to provide the level of emissions reductions needed to achieve the AB 32 targets in the electricity and natural-gas sectors. For a variety of compelling reasons, both programs would benefit from the immediate establishment of stretch goals for 2020, which corresponds to the compliance target date for AB 32 compliance. The GPI's focus is on the establishment of the RPS stretch target of 33 percent renewables by 2020. Achieving 33-percent renewables in 2020 reduces annual greenhouse-gas emissions by 35 – 65 million tons of CO_2 equiv., depending on the mix of gas and coal generation that is avoided, compared to current electricity-sector emissions levels, in which renewables contribute 10 – 11 percent statewide. Twenty percent renewables in 2020 only provides only about half as much reduction from current emissions levels (~13 – 30 million tons of CO_2 equiv. per year). Enacting the 33 percent stretch target for the RPS program will thus avoid an additional 22 – 35 million tons of CO_2 equiv. emissions annually, compared to maintaining 20 percent as the ultimate RPS statewide target level.[5] This would represent a major contribution to the state's efforts to comply with AB 32.

The core of our argument in favor of enactment of the stretch target for the RPS program is that the only compelling rationale for accelerating the state's 20-percent RPS target deadline from 2017 to 2010, was so that the accelerated goal could be backed up by a higher, longer-term stretch goal for renewables. Otherwise, the policy would result in a quick burst of development activity in the state's renewable energy sector, followed by an abrupt and precipitous halt. Those are not the kind of conditions that are conducive to the development of a stable, sustainable renewable energy industry in the state. Renewable energy generation is a highly capital-intensive enterprise, and in order to sustain a flow of investment capital into the renewable energy sector in California, adopting a long-term stretch goal for renewables is highly desirable.

Uncertainty regarding long-term renewables policy has long been a major impediment to attracting investment capital. The stretch target of 33 percent renewables by 2020 is exactly the kind of market assurance that can lead to the development of the sustainable renewable energy industry that Californians overwhelmingly desire. Moreover, because of the long lead time that is still available today for reaching the stretch goal, combined with the head-start that has been provided by the acceleration of the original twenty-percent goal to 2010, it will actually be easier for the LSEs to reach the 33-percent by 2020 standard than it ever was for them to reach 20-percent renewables by 2010, which nearly everyone acknowledges will not happen. The Figure below illustrates graphically how this is the case:

[5] Note that these figures do not take into account subsequent WECC-wide adjustments that might occur.

Illustrative Scenario for 33 Percent Renewables by 2020



The renewables procurement curve in the figure is based on actual procurement data for 2003 – 2006 provided by the three IOUs in their *RPS Compliance Reports* (renewable procurement and retail sales data), and a growth rate for composite IOU retail sales of 1.5-percent per year. The near-term part of the projection shown in the figure, 2007 – 2009, is based on maintaining the entire existing renewable infrastructure that is currently serving the three IOUs, augmented by the scheduled startups of new renewable capacity under development for the three IOUs, with a 70-percent success rate applied to all greenfield and restart contracts. The long-term part of the projection, 2010 – 2020, is based on constructing a reasonable, illustrative scenario for connecting the 2003 – 2009 data to a 33 percent outcome by 2020. The driving force behind the scenario in the figure is attaining the 33-percent renewables target in 2020.

The RPS penetration curve for the three IOUs shown in the figure illustrates a scenario that, we believe, the three IOUs could realistically achieve, although not without diligent and sustained future procurement efforts on their parts. As of the beginning of 2007, the IOUs have a composite renewable content of approximately 13½-percent in their energy mix. Counting only their existing portfolios of operating renewable generators and development projects that are under contract, the utilities are well behind the curve shown in the figure. In order to get onto the renewables-growth scenario illustrated in the figure, they will have to be far more effective in their future RPS solicitations than they have been in any of the solicitations that have been conducted so far.

Question no. 3 on page 2 of the May 13, 2008, ALJ's *Ruling*, asks whether there are any overlap or compatibility issues between the RPS program and the participation of the electricity sector in a greenhouse-gas cap-and-trade program. There is certainly an overlap between the RPS program and participation in a cap-and-trade program for electricity, because renewable energy is one of the major options available for reducing electric-sector greenhouse-gas emissions. This overlap is wholly compatible with the participation of the electricity sector in a cap-and-trade program, because even adopting the 33-percent-by-2020 stretch target does not, by itself, provide anywhere near the amount of emissions reductions reductions required statewide by AB 32. The remainder of the required emissions reductions will have to come from new stretch goals in EE, DR, and additional reductions provided by the cap-and-trade program.

VI. C. Annual Emission Caps for the Electricity and Natural Gas Sectors

The EE and RPS programs express their programmatic targets in term of electricity avoided or delivered, not in terms of greenhouse-gas emissions. Indeed, the greenhouse-gas emissions associated with the electricity and natural gas sectors are mainly related to the use of fossil fuels, the extent of which is indirectly related to the amounts of EE and renewables that are contributing to the supply mix. Setting sector-wide greenhouse-gas emissions caps for electricity and natural gas is a completely different matter than setting programmatic targets for EE and the RPS.

The language of AB 32 is very clear in instructing that the statutes establish overall greenhouse-gas emissions targets for the state, but that they do not set any sector-specific targets, preferring to allow maximum flexibility in implementing the program. Question 4 on page 2 of the May 13, 2008, ALJ's *Ruling*, states that: "The scope of this proceeding includes making recommendations to ARB regarding annual GHG emissions caps for the electricity and natural gas sectors." The question then solicits suggestions about how to proceed. Our overriding recommendation is that regardless of what approach is eventually adopted for recommending sectoral caps, the joint Commissions' recommendation should make clear that the sectoral caps should be treated as rough guidelines, to be used only for purposes of planning and crafting policy measures. The sectoral caps should not be treated like the AB 32 statewide statutory mandates, which are both obligatory and absolute.

The natural tendency is to set sectoral caps that provide emissions reductions proportional to the statewide reductions required by AB 32, absent a compelling rationale for doing otherwise. In this case, the GPI believes that there are significant factors that should be considered that indeed might convince the Commissions to recommend sectoral caps for electricity and natural gas that are not directly proportional to the overall level of mandated reductions. These factors push in opposite directions for the electricity and natural gas sectors.

The electricity sector can draw its energy supply from a wide variety of resources, ranging from the most carbon-intensive fossil fuel (coal), to sources like renewables that are essentially zero-emitters of greenhouse gases. In addition to adjusting the mix of supply options, electric-sector emissions can also be reduced through energy-efficiency measures. Other major energy-using sectors, such as transportation and natural gas, have far fewer options available to them for reducing emissions, mainly limited to efficiency measures. The implication of this fundamental difference between the electricity and other major energy-using sectors is that it is reasonable to expect that the electricity sector will be able to provide proportionally greater amounts of cost-effective emissions reductions than other energy-intensive sectors. The corollary is that the natural-gas sector, which lacks low-carbon supply alternatives,[6] might appropriately be expected to provide proportionally less emissions reductions than other sectors, and certainly proportionally less than electricity.

It is important to note that a multi-sector cap-and-trade market for greenhouse-gases is expressly intended to act as a mechanism for allowing the marketplace to identify the most cost-effective alternatives from among all energy-using activities for achieving the

[6] As we noted in our December 17, 2007, *Comments* in this proceeding, biogas resources can be upgraded to carbon-neutral, pipeline-quality gas, but the underlying resource is limited in quantity, and demand for renewable biogas in the electricity and transportation sectors is likely to claim most of the available supply.

mandated statewide emissions levels specified in AB 32. In other words, the cap-and-trade system is meant to encourage inter-sectoral transitions, where such transitions provide a cost-effective means to reduce greenhouse-gas emissions. To the extent that sectoral emissions caps or guidelines are established as part of the process of implementing AB 32, there needs to be a mechanism developed for adjusting the sectoral targets to accommodate such changes. A prime example is the possible transition in transportation energy use from gasoline to electricity. Hybrid vehicles are claiming an increasing fraction of the automobile market, and many analysts believe that the next step will be plug-in hybrids, followed eventually by all-electrics. To the extent that this transition does occur, and that it proves to provide automobiles with a reduced greenhouse-gas footprint, the sectoral caps should be adjusted accordingly.

VII. Modeling Issues

The updated version of the E3 greenhouse gas calculator is much easier to use than the original model, and allows the user to see many different cases at a time, which is a significant improvement. In addition, the new cases that E3 has provided are helpful in showing how the calculator can be used. The E3 model is sufficiently useful to be used by the joint Commissions in developing recommendations for the ARB. However, the cases prepared by E3 should only be used as a base of departure. Other cases should also be developed by participating parties that might bring to light the variables that they see as most important. The E3 model is only a calculator, and must be used in conjunction with other tools in crafting recommendations for ARB.

The input assumptions used by E3 in both the reference case and the other cases it has prepared appear to us to be valid. E3 has done a good job of estimating inputs based on the current market, and it has done some good work in estimating future markets. One thing that may not be possible to model is a large change in the market, such as a change in technology. While E3 may not be able to model such a market change, it is important to keep it mind that such a change is possible, even probable given the amount of effort going into improving technology and finding new energy sources.

Our major concern with the E3 calculator is that it is a very large spreadsheet, with a great deal of potentially hidden interactions that a model user may not appreciate or anticipate, which could lead to conclusions that are not what the modeler thinks they are. Based on our use of the model to date, one unmistakable conclusion is that in order to use the calculator reliably and effectively, the modeler requires a good deal of training and practice.

Conclusion

The forthcoming Decision, to which this round of *Comments* and *Replies* contribute, is an extremely important one. The ultimate success of AB 32 may well depend on it. We urge the Commissions to deliberate carefully, despite the time pressure imposed by the legislation, in order to be fully confident before rolling out what is likely to be a very closely watched innovation. In particular, we believe that the initial program should be based primarily on establishing stretch goals for the RPS and EE programs, with a cap-and-trade program used to provide additional needed emissions reductions. Emissions allowances should not be distributed free-of-charge, regardless of the allocation method that is chosen. Linkage and offsets should be a part of the market design, but it is reasonable to impose restrictions on out-of-jurisdiction participation in California's AB 32 program, especially in the early years.

Dated June 2, 2008, at Berkeley, California.
Respectfully Submitted,

Gregg Morris

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PROOF OF SERVICE

I hereby certify that on June 2, 2008, in Berkeley, CA, I have served a copy of the COMMENTS OF THE GREEN POWER INSTITUTE ON ALLOCATION, MODELING, AND FLEXIBLE COMPLIANCE upon all parties listed on the Service List for this proceeding, R-06-04-009. All parties have been served by email or first class mail, in accordance with Commission Rules.

Gregg Morris

Gregory Morris