**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

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

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AB 32 Implementation – Greenhouse Gas Emissions.	Docket 07-OIIP-01

COMMENTS OF THE WESTERN POWER TRADING FORUM ON DESIGN OF GREENHOUSE GAS REGULATORY STRATEGIES

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In accordance with the direction provided in the May 20th, 2008, Administrative Law Judge's Ruling under Rulemaking 06-04-009, the Western Power Trading Forum ("WPTF") respectfully submits the following opening comments on the questions raised regarding design of a GHG trading system for the electricity sector. WPTF supports an approach to GHG regulation that is effective, equitable, cost-effective and can address climate change in the long-term. In our view, a well-designed multi-sector cap and trade system best meets this objective.

WPTF considers that a cap and trade will be most efficient if it maximizes the ability of capped entities to plan for compliance, deal with emissions variability and price volatility, and use the lowest cost emission reductions for compliance. Specifically, WPTF recommends that California adopt a multi-sector trading system that provides temporal flexibility to capped entities to comply through unlimited banking and rolling multi-year compliance periods, and provides access to low-cost emission offsets.

WPTF opposes price caps as a cost-containment mechanism, and instead recommends the establishment of a body with limited authority to monitor the GHG market and advise the

Governor in the event that intervention is needed in the GHG market to avoid severe economic consequences.

WPTF urges the Commissions to recommend design elements that will be consistent with, and allow easy integration into, the emerging federal policy, which clearly is evolving towards an economy-wide cap and trade system.

More detailed information on these positions is provided in the responses to the questions below. These questions follow the order suggested in the May 20, Administrative Law Judge Ruling under this proceeding. However, we have not included all questions identified in the ruling. In addition, we have included an appendix which contains information on an alternative allocation scenario using the Energy and Environmental Economics' ("E3") model.[1]

General Issues

1. 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.

WPTF believes that the same set of criteria should be used in assessing each issue discussed in these comments, as well as the overall design of the cap and trade system. In our view, all rules/elements should be designed to ensure that the cap and trade system should:

- Be effective in achieving short and, more-importantly, long-term emission reductions;
- Promote consistency with the design and rules of an expected future federal GHG trading program;

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[1] See, Appendix A, Documentation of WPTF Alternative Modeling Scenario, attached hereto.

- Ensure equitable treatment of the electric sector relative to other sectors and individual 'first deliverers';
- Have clear and simple rules to promote market certainty and enable planning of compliance; and
- Provide sufficient flexibility to capped entities in acquiring allowances and credits to enable them to deal with variability in emissions levels and market conditions from year to year.

2. Address any interactions among issues that you believe the Commissions should take into account in developing recommendations to ARB.

WPTF would like to raise a concern regarding the Commissions' stated intention with respect to achievement of GHG emission reductions in the electric sector. In the March 13th "Interim Opinion on GHG Regulatory Strategies," the Commissions stated:

> "In order to meet the AB 32 goals, the IOUs and POUs should be required to go beyond a 20% level of renewable electricity delivered. Therefore, we recommend that the Energy Commission, Public Utilities Commission, and ARB jointly seek legislation that requires retail electricity providers to obtain a greater proportion of their power from renewables by a date certain, with flexibility to allow the Public Utilities Commission and/or ARB to require exceeding that level under certain conditions (subject to a cost-effectiveness evaluation, for example). The Energy Action Plans jointly adopted by the Public Utilities Commission and the Energy Commission commit us to "evaluate and develop implementation plans for achieving 33 percent renewables by 2020, in light of cost-benefit and risk analysis." While achieving renewable energy deliveries at this level would contribute significantly to attainment of the emissions reductions required by AB 32, we leave open consideration of the appropriate statutory percentage requirements and deadlines, pending further analysis."

The results of the GHG analysis conducted by the CPUC bring the cost-effectiveness of an increase in the Renewables mandate to 33% squarely into question. E3's modeling analyses finds an implicit carbon price for incremental new renewable beyond the current 20% RPS to be around $133/ton. While renewable energy clearly will and must play an integral role in reducing

GHG emissions, there are likely to be many emission reduction opportunities in other sectors or through offsets that are lower cost than an increasing the proportion of renewables. A GHG trading system will allow the market to find these opportunities when they become cost effective, as the cap is reduced and/or the availability of more cost efficient reduction measures are exhausted. In contrast, an enhanced RPS is flawed as a GHG policy tool because it implicitly presumes that renewable resource development is more cost effective than other emission reduction opportunities that are achievable elsewhere or through different technologies.

3. 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?

The Commissions' fundamental goal in this regard should be to ensure that California-issued allowances and recognized offsets are fully valid for use within a federal, and ultimately international, system in order to ensure that the California economy and its consumers are able to achieve emission reductions in the most cost effective manner possible, and so that the investments made in California will not be devalued when federal and international programs are implemented. This can be achieved by ensuring that the California system has the same basic architecture, is of comparable rigor, and can readily transition to the emerging federal program.

4. 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.

WPTF considers that the level of detail and specificity regarding regulation of the electric sector currently contemplated in this proceeding (i.e. point of regulation sectoral cap, allocation methods and percentages and timeframe) are appropriate for the August recommendation to the Air Resources Board. However, we believe that more detail will be needed with respect to implementation of the first deliverer approach, and that such detail should be provided in a subsequent recommendation prior to finalization of the Scoping Plan.

Additionally, as is the architecture and details of the emerging federal GHG program become clearer, or should neighboring states adopt GHG emission reduction plans first, there will likely need to modifications to the first deliverer approach in California to ensure that the California approach can readily transition to a broader integrated market.

5. 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. Discuss how your proposal would affect the environmental integrity of the cap, California's ability to link with other trading systems, and administrative complexity. Address how your various recommendations interact with one another and with the overall market and describe what kind of market you envision being created.

WPTF considers that the most effective tools for containment of costs within the GHG trading system are the scope and design of the system. First and foremost, the success of the cap and trade system will be dependent on providing a carbon price signal that is high enough to incentivize incremental changes in generator dispatch, long-term investments in low-GHG technologies, demand response and efficiency measures. The overall approach to cost-containment should ensure the robustness and transparency of the carbon-related price signal and ensure the ongoing environmental integrity of the cap and trade system. In addition, broad sectoral coverage, multi-year compliance periods, use of real, verified offsets and unrestricted ability to bank allowances and offsets and will increase market liquidity, dampen volatility, expand opportunities for low-cost GHG reductions, and substantially reduce the risk of unacceptably high costs and severe economic consequences.

Finally, WPTF supports establishment of a body with limited authority to monitor market conditions, and to advise the Governor if intervention in the market is needed. WPTF does not support establishment of a price cap.

6. 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?

Implementation of the California system should specifically avoid the inclusion of a prescriptive price cap, as that would conflict with a federal program in the event that the federal program does not adopt a price cap, or adopts a more flexible approach (such as a market oversight body). In addition, a prescriptive price cap would create an impediment to linkage with other GHG trading systems, such as the European Union Emissions Trading System ("EU ETS") that do not use price caps.

While WPTF supports the unlimited use of offsets in a federal system, California's rules with respect to offsets should be consistent with the federal program, including any limitations that may be imposed at the federal level. In this regard, WPTF urges California regulators to periodically revisit the program's rules in light of the evolving federal approach.

7. What evaluation criteria should be used in assessing flexible compliance options?

WPTF considers that the cost-containment measures should avoid interference in the GHG trading market, maintain the carbon price signal and maintain the environmental integrity of the emission targets. These objectives can, for the most part, be met through design of a broad-based GHG trading system, with offsets and temporal flexibility for capped entities, as described in response to question 5. However, to the extent that a 'safety-valve' is needed, WPTF recommends that this be limited to true damage control, such as avoiding electric system reliability problems, and should not be triggered by price volatility. In our view, such a standard is clearly and appropriately established by AB32, which authorizes the Governor to adjust the timing and level of GHG reductions in the event of "extraordinary circumstances, catastrophic events or the threat of significant economic harm."

<u>**Allocation Issues**</u>

8. Please explain in detail your proposal for how GHG emission allowances should be allocated in the electricity sector.

Administrative allocation should be the principal means of distributing emission allowances in the early years of the trading system, with a gradual transition to auctioning over time. A gradual transition to auctioning is preferable to immediate 100% auction, as this will enable entities subject to the emissions cap to plan for compliance and invest in GHG reduction technologies and practices.

9. 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.

WPTF believes that for maximum efficiency in reducing GHG emissions, electricity consumers must be fully aware of the carbon costs that there electricity consumption creates. Therefore, any mechanism that returns auction revenue to consumers should do so in a way that does not discourage consumer energy efficiency. Year-end rebates of auction revenues would be an acceptable auction revenue return mechanism, whereas an application of auction revenues to directly reduce electricity rates, for instance through a reduction in transmission or distribution rates, would not.

WPTF notes that the long-term costs of achieving emission reductions may be much higher than they will be in the early years of the program, due to the increasing scale of emission reductions required to stabilize atmospheric GHG concentrations and the fact that energy technologies to achieve such long-term reductions do not yet exist. For this reason, we believe that consumer interests are better served by dedicating a substantial portion, if not all, of the auction revenues to specific programs that develop and deploy GHG control technologies, rather than providing direct or indirect short term rate relief.

10. 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.

WPTF strongly opposes allocation of allowances to retail providers under a first deliverer point of regulation, especially when the allocation is made only to jurisdictional retail providers. As we have stated numerous times in this proceeding, jurisdictional retail providers would have an inherent conflict of interest as the recipient of the allowances because in most instances, they also (i) own generating resources and/or (ii) are in direct competition with non-jurisdictional entities for providing electricity to retail load. Thus, a direct allocation of allowances to jurisdictional retail providers would potentially confer an unfair competitive advantage to utility-owned resources in procuring allowances, and create a concentration of market power. WPTF believes that imposing this direct conflict of interest on jurisdictional entities should be avoided in order to promote confidence in the GHG trading system. If the Commissions determine that some portion of allowance value should be allocated to jurisdictional retail providers for the purpose of providing a rebate to consumers then this would be better achieved by allocating auction revenue to retail providers – not actual allowances.

11. 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.

WPTF recognizes the concern regarding potential windfall profits to independent power producers, but believes these concerns exaggerate the potential for these profits. Electric generators will face substantial compliance costs under GHG regulation. The level of emission reductions needed from the power sector to meet long-term climate stabilization goals will require substantial new investment by generators in carbon control technologies. Administrative allocation of allowances to delivers in the early years of the trading program will enable generators to retain the resources needed for long-term investment in cleaner technologies and fuels.

Further, much of the economic literature on GHG trading, including that cited in the Staff Options Paper on Allocation recognizes that an administrative allocation that transitions to auction over time will substantially reduce the potential for windfall profits, while easing the transition to GHG control technologies and practices. WPTF has used the E3 model to evaluate a scenario that transitions to auctioning at a slower rate than the staff "preferred allocation approaches." Specifically, the percent of allowances distributed by auction is initially set at 25% and increases 10% annually. Relative to 'pure historic allocation," this scenario[2] results in a 50% reduction in producer surplus and an overall cost reduction of $10 billion. Comparison to a "pure output-based allocation" would yield similar results.

12. 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?

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[2] Documentation of this scenario is provided in Appendix B, GHG Calculator Scenario Documentation, attached hereto.

WPTF does not have a suggestion for the specific percentage to be allocated but suggest the Commissions determine the most cost effective methods for promoting investments in these programs and their goals for each. Then the Commissions should determine the cost associated with attaining those goals and appropriate the corresponding amount of revenue to accomplish those goals.

13. 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.

As stated in question 9, WPTF believes that direct refunds would be a better way to distribute revenue because it does not dilute the price signal to energy consumers. WPTF does not have any comment, however, on how rebate funds should be allocated among different consumer groups.

Flexible Compliance Mechanisms/Cost-Containment

14. 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.

Electricity generation is highly subject to variability in weather and load conditions, with the result that emission levels may fluctuate greatly from year to year. Since allowances will be de facto operating permits, a shortage of allowances in a given year could be detrimental to grid reliability. For this reason, it is critical that the cap and trade design provide first deliverers with the ability to deal with such fluctuations by enabling development of a deep and liquid secondary market, by providing linkages to other trading systems and a viable offset market, and by allowing temporal flexibility in the use of allowances.

15. 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.

WPTF recommends (and assumes) that California will adopt a multi-sector cap and trade program. However, WPTF's specific recommendations herein are not dependent on the inclusion of any particular sectors in the program. In addition, we assume that all capped sectors will be expected to undertake a comparable level of reductions.

In our view, the purpose of flexible compliance mechanisms, specifically temporal flexibility, linkage to other trading systems and an offset market is two-fold. The first is to reduce overall costs of achieving GHG reductions and minimize market volatility. The second is to avoid serious negative consequences, and thus trigger of the more aggressive cost-containment mechanism implicit in the AB32 safety-valve.

16. 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?

WPTF believes that the most effective tools for containment of costs within the GHG trading system are the scope and design of the system. Broad sectoral coverage, multi-year rolling compliance periods, unlimited banking and use of real, verified offsets will increase market liquidity, expand opportunities for low-cost GHG reductions, and substantially reduce the risk of unacceptably high costs. In general, the broader the scope of the trading system, the less risk there should be of unacceptable consequences.

Flexible compliance mechanisms are core components of market design, and should therefore be a core part of the Commissions' recommendations.

17. 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 be 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?

There should not be any restrictions on which entities may participate in the GHG markets. Allowing market intermediaries to participate in the market will increase market liquidity and ultimately reduce the transaction costs of trading. Further, because a first deliverer approach will be used in the California system, it will be difficult – if not impossible – to determine *a priori* which entities will have compliance obligation, since a myriad of different entities, including financial organizations and marketers, regularly deliver power in the California energy markets. Concerns about market manipulation should be addressed through appropriate market oversight, not by barring these entities from the market.

18. Price triggers and other safety valves could be used if there is a need to intervene in normal market dynamics to restore allowance prices back to acceptable levels. 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.

While WPTF recognizes that AB32 contains an implicit safety-valve, the use of a safety-valve option should limited to true damage control and should not be triggered by price volatility. It should also ensure that the environmental integrity of the cap and trade system remains intact. For instance, if the safety value calls for loosening of the cap in one year, for instance through issuance of additional allowances, the overall integrity of the cap should eventually be restored by a reduction in the cap in future years. Under no circumstances, should there be a cost containment approach that is tied to a prescriptive and inflexible price trigger because such an approach would eliminate the effectiveness of the cap and trade program to accurately reflect carbon costs. Rather, concerns about program cost should be addressed up-front, through evaluation and setting of the appropriate level of the cap.

WPTF also supports the establishment of an oversight body with limited authority to monitor market conditions, and to advise the Governor if intervention in the market is needed. Establishment of such a body would provide flexibility in identifying and responding to unforeseen circumstances without the need to rely on an inflexible, prescriptive price trigger.

WPTF also urges the Commissions to avoid implementation of an approach under which any quantitative and/or geographic limits on the use of offsets are relaxed when certain price thresholds are reached. Linking the use of offsets to the price of allowances makes it exceedingly difficult for capped entities to plan for the use of offsets in their compliance portfolio, and discourages investments in valid GHG reduction projects.

19. 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 response to question 18 above.

20. The issue of linkage addresses the ability of obligated entities to buy and sell GHG emission allowances or credits with other carbon-trading systems like the Regional Greenhouse Gas Initiative and the European Union Emissions Trading Scheme. 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.

Numerous studies have demonstrated that allowing offset credits has the potential to significantly reduce the costs of achieving GHG reduction targets.[3] For this reason, WPTF supports the broad use of offsets within California's cap and trade system. However, in the event that quantitative or geographic restrictions on the use of offsets are imposed, there should be a clear roadmap established for expanding the use of offsets over time in order to provide market and regulatory certainty, and to ensure that the most cost effective emission reduction measures are implemented over time. For instance, if offsets for a California cap-and-trade program are initially limited to offsets geographically located within the states that are members of the Western Climate Initiative ("WCI"), it should be made clear that the use of offsets is intended to expand consistent with the implementation of additional regional programs, a federal program, and international programs.

WPTF also supports linkage of the California system to other compatible systems, such as RGGI and the WCI. However, we note that full linkage with the European and UNFCCC systems is not possible at this time, due to the fact that California emission allowances would not be recognized and accepted by those programs. While we would support unilateral linkage of California's trading system with international programs, this should not be high priority. As WPTF has previously stated, development of a national GHG reduction program is a preferred approach to both link the US states in the reduction efforts and to engage in the international arena.

21. 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

[3] For example, EPA Analysis of the Lieberman-Warner Climate Security Act of 2008 concluded that unlimited use of domestic offsets would reduce the costs of achieving emissions targets under the bill by about 62%, relative to a scenario under which offsets are not allowed.

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?

Linkage with other trading systems will reduce costs if emission reduction opportunities (and hence allowance prices) in those systems are lower than in the California system, with the result that more reductions are achieved out-of-state than would the case if prices are equal. If allowance prices in California are lower than in other systems, then increased demand for California allowances in these other systems will increase allowance prices in California, and result in a greater quantity of reductions achieved in-state.

22. 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)?

Linkage with other US programs (e.g. RGGI, WCI) should be bilateral. As a practical matter, we do not see how California could restrict the use of its allowances and recognized offsets in other programs, as this is determined by the rules of that program.

At this point in time, linkage with international programs could only be unilateral, as California offsets could not be used by other countries to meet Kyoto Protocol commitments due to the fact that the US is not a Party to that agreement. While ultimately, WPTF believes that linkage of a California program with other international programs will be beneficial, we believe such linkage should and will occur as the federal program is developed, and should therefore not be a priority for the state.

23. 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?

Allowances from other US programs should not be subject to quantitative limits within the California program. As WPTF has stated previously, we believe that a single, uniform, comprehensive federal GHG trading program should be the ultimate objective. Policies that restrict the use of US allowances based on the source of those allowances would run counter to this objective.

24. 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?

WPTF believes that temporal flexibility for capped entities is an important means of containing costs of the GHG trading system. For this reason, WPTF advocates multi-year compliance periods of 3 – 5 years. However, we note that discrete compliance periods provide entities with flexibility to use future year allowance budgets in the early years of the compliance period, but increasingly limited flexibility as the compliance period progresses, and no flexibility in the final year. If the final year turned out to be anomalous due to weather and economic conditions, then capped entities could have difficulty acquiring sufficient allowances for compliance. In order to avoid this unintended consequence, and the potential for triggering the AB32 safety-valve provision, WPTF suggests that the Commission recommend a rolling compliance period.

Under this approach, capped entities would be required to surrender allowances annually to cover emissions in the previous year, but in exchange would always be able to use a limited quantity of allowances from the next year (plus any allowances banked from previous years.) This approach would be similar to that used in the EU ETS. Under the EU ETS, allowances do not have an annual vintage but rather a compliance period vintage (e.g. Phase 2, which covers 5 years), and may be used for compliance in any year of the period. Each member state must issue

1/5th of a sector or installation's overall allowance budget by February 28th of a compliance year. Capped entities must then surrender sufficient allowances to cover emissions from the previous year by April 30th. The fact that allowance surrender for the previous year occurs after allocation of allowances for the subsequent year, means that each entity can avail itself of 2 years worth of allocations for compliance in any given year.

WPTF considers that allowing entities to borrow a limited quantity of allowances from the subsequent year allocation would yield significant benefits. Additionally, we note that such an approach would be compatible with any method of allocating allowances.

We do not believe that staggering compliance periods would be necessary under a rolling compliance period approach, because the increase availability of allowances in the market would offset the increased demand for allowances due to an impending compliance date.

25. Should compliance extensions be granted? If so, under what circumstances?

WPTF sees no benefit in granting compliance extensions. Nor should there be any specific criteria will automatically result in an extension. Any element of the program that deals with the potential for compliance extension (or waivers) should be designed to act on a case by case basis.

26. Banking would allow an entity to buy and hold GHG emission allowances and/or credits across compliance periods; borrowing would allow an obligated entity to use its allowances from a future compliance period to meet the obligation under a current compliance period. 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?

WPTF supports unrestricted banking of allowances by all market participants. Banking enhances market liquidity, incentivizes over-compliance in the early years of the program, and provides important flexibility to capped entities for long-term compliance planning. This latter point is particularly important in light of the projected costs of achieving levels of emission reductions required in the long-term.

27. Should limitations be placed on banking aimed at preventing or limiting market participants' ability to "hoard" allowances and offsets or distort market prices? 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.

Ensuring that all capped entities have equal access to allowances and that any allocation method is equitable and does not allow creation of market power will reduce the risk of hoarding, as will a requirement that entities annually surrender allowances to cover previous year emissions. In general, WPTF does not support any restrictions on banking of allowances.

WPTF supports limited borrowing of units within a rolling compliance period (see response to Q24 above. We do not believe that such limited borrowing would reduce the environmental integrity of the trading system, provided that entities are required to surrender allowances on an annual basis and that penalties for non-compliance are substantial and enforced.

28. 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?

Capped entities within the GHG trading system should be subject to strict penalties for failure to surrender sufficient allowances and/or offset credits to cover emissions. Payment of the penalty should not discharge the non-compliant entity's obligation to make the environment whole.

To this end, WPTF recommends that compliance penalties should be set relative to and higher than the market allowance price (e.g. 1.5 times the allowance price for each ton in excess of surrendered allowances) so as not to incentive non-compliance. Revenue from non-compliance penalties should be used to make the environment whole through the purchase and retirement of allowances equivalent to the excess emissions. Penalties should also be applied for failure to comply with GHG reporting requirements.

29. 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?

WPTF opposes the use of alternative compliance payments because alternative compliance payments would operate as a de facto price ceiling, and undermine the environmental integrity of the trading system. In addition, an alternative compliance payment would compromise the effectiveness of the carbon price signal.

30. 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?

Payment of a compliance penalty should not enable a capped entity to forego its compliance obligation or opt-out of the market. See response to question 28 above

31. How should California use the money that would be generated by penalties and/or alternative compliance payments?

As described in question 28, if the penalty program calls for the penalty payment to be used to purchase the missing allowances, that that would account for how a portion of the revenue would be used. Any excess could also be used to fund technological development, or for other GHG related purposes.

32. Should California allow offsets for AB 32 compliance purposes?

Numerous studies have demonstrated that allowing offset credits has the potential to significantly reduce the costs of achieving GHG reduction targets.[4] For this reason, WPTF supports the use of offsets for compliance within California's cap and trade system.

33. 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?

WPTF does not have a position on the type of offsets that should be allowed in the California system, but considers that these should be such be subject to rigorous requirements to demonstrate that they are real, credible and verified.

In the event that restrictions on the use of offsets are imposed, there should be a clear roadmap established for expanding the use of offsets over time in order to provide market and regulatory certainty, and to ensure that the most cost effective emission reduction measures are implemented over time. For instance, if offsets for a California cap-and-trade program are initially limited to offsets geographically located within the states that are members of the Western Climate Initiative (WCI), it should be made clear that the use of offsets is intended to expand consistent with the implementation of additional regional programs, a federal program, and international programs. Thus, while WPTF can accept some quantity or geographic restrictions on the use of offsets during a transition period, WPTF urges the Commissions to avoid implementation of an approach under which both the quantitative and geographic limits on

[4] For example, EPA Analysis of the Lieberman-Warner Climate Security Act of 2008 concluded that unlimited use of domestic offsets would reduce the costs of achieving emissions targets under the bill by about 62%, relative to a scenario under which offsets are not allowed.

the use of offsets are relaxed when certain price thresholds are reached. Linking the use of offsets to the price of allowances makes it exceedingly difficult for capped entities to plan for the use of offsets in their compliance portfolio, and discourages investments in GHG reduction projects.

34. 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?

Voluntary GHG emission reduction projects should be allowed as offsets provided the associated emission reductions can be reliably quantified and verified.

WPTF believes that the natural gas sector will be included in federal GHG cap and trade system. Therefore, while we would support allowing GHG offsets from the natural gas sector in a California-only context, such an approach would likely be inconsistent with an eventual federal program.

35. Should there be limits to the quantity of offsets? If so, how should the limits be determined?

See the response to question 33 above.

36. 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?

WPTF currently has no position on the administration of an offset program, nor the appropriateness of various offset protocols, other than to note that California's decision to accept credits from other trading programs, including those generated in other countries under the Kyoto Protocol, should be based on a determination that the respective program applies rigorous standards for estimating and certifying those offsets. Once California decides to allow offsets generated from a particular program, it should fully recognize and accept the certification of that program and not require additional state certification.

37. Should California discount credits (i.e. make the credits worth less than a ton of CO_2e) 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?

WPTF does not support discounting of offset credits, as this would add complexity to the administration of the program and for compliance planning. The GHG market will operate most efficiently if all allowances and offset credits are fully fungible.

Uncertainty in the level of emission reductions generated by a particular project type can and should be addressed through the use of conservative methodologies for estimating emission reductions, and/or by applying rigorous standards to establishing the credibility and verification mechanisms used to certify offsets.

Treatment of CHP

38. 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.

WPTF recognizes that CHP facilities provide GHG and other social benefits. In this regard, the GHG trading program should regulate CHP facilities in a manner that treats them fairly, and does not provide disincentives for further development. However, the GHG trading system should not give CHP facilities a competitive advantage over other electric generators.

WPTF recommends that emissions associated with electricity from CHP plants, regardless of whether consumed on or offsite, be regulated in the same way as the electricity sector broadly. WPTF does not propose a specific mechanism for recognizing or crediting the emission reductions from CHP facilities.

39. Should GHG emissions from CHP systems be regulated in one sector? If so, which one? How?

All emissions from electricity generated by CHP units, whether consumed on-site or delivered to the grid, should be regulated. While it may be workable to regulate emissions from electricity from CHP facilities separately from the rest of the electric sector, we believe that it would be administratively simpler to regulate these emissions within the electric sector.

The question of how to regulate emissions associated with the thermal output of CHP facilities is more complicated, as it is not yet clear whether industrial natural gas consumption will be regulated under the cap and trade system. WPTF recommends that emissions associated with the thermal output of CHP plants should be treated and regulated in the same way as other emissions from natural gas combustion in industrial and commercial applications. If industrial natural gas consumption is included in the cap and trade system, than emissions associated with the thermal output of CHP facilities should also be included (subject to any emission thresholds that ARB may adopt). If industrial natural gas is not included, then emissions associated with the thermal output of CHP facilities should not be included either.

40. For in-state CHP systems, should all of the GHG emissions (i.e., all of the emissions attributed to the electricity generation and to the thermal uses) be regulated as part of the electricity sector? If so, for the electricity that is delivered to the California grid, should the deliverer as defined in D.08-03-018 be the point of regulation? And, what entity(ies) should be the point(s) of regulation for thermal usage and electricity that is not delivered to the California grid if those uses are included in the electricity sector for GHG regulation purposes?

For in-state systems, all of the emissions attributed to electricity generation should be regulated with the electricity sector. Emissions associated with thermal use should be regulated in the same manner as other emissions from industrial and commercial natural gas consumption.

41. For out-of-state CHP systems, how should GHG emissions attributed to the electricity delivered to the California grid be regulated? If part of the electricity sector, should the deliverer of the CHP-generated electricity

delivered to the California grid be the point regulation? (These questions are based on our view that, for out-of-state CHP systems, only emissions attributed to electricity delivered to California, and not attributed to other electricity or the thermal output, are subject to AB 32.)

WPTF agrees that for out-of-state CHP systems, only emissions associated with electricity delivered into California should be regulated under the cap and trade system.

42. Should electricity delivered to the California grid by a CHP unit be regulated under the deliverer point of regulation established in D.08-03-018? Why or why not?

All emissions from electricity delivered to the California grid should be regulated. If emissions from this electricity generation were exempted, the increased price for wholesale power would create opportunities for CHP facilities to profit by increasing the quantity of electricity sold to the grid without facing any commensurate GHG obligation. Such an outcome would compromise AB32 goals.

43. Should electricity generated by in-state CHP systems for on-site use be subject to the same regulatory treatment as CHP electricity delivered to the California grid? Why or not?

Electricity generated by in-state CHP systems for on-site use should be subject to the same regulatory treatment as CHP electricity delivered to the California grid. Exemption of emissions from electricity consumed on-site would means that CHP facilities do not see a carbon price reflected in electricity prices, while all other California consumers of electricity would. This would advantage the industrial or commercial activities of CHP facilities relative to its competitors within that sector.

44. Would including all of CHP in cap and trade create a disincentive if natural gas is not regulated under cap and trade?

Inclusion of emissions from the thermal output of CHP facilities could be a disincentive for further development, if emissions from industrial and commercial natural gas consumption are not also included.

<u>Emission Caps/non-market-based mechanisms</u>

45. 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?

Current mandates for energy efficiency and renewable procurement should be expanded to apply to non-CPUC jurisdictional utilities.

WPTF believes that the implementation of a multi-sector cap and trade system is the most effective and efficient means of achieving GHG reductions in the electricity sector over the long-term. We therefore do not advocate adoption of additional programmatic or regulatory measures to achieve AB32.

46. 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?

WPTF does not agree with the premise of this question. One of the advantages of a cap and trade system is that it does not necessitate determination of where emission reductions are achieved. The Commissions' own analysis suggests that existing energy efficiency and renewable energy mandates will achieve the 2020 emission reduction targets. Imposition of a cap and trade system on top of these mandates will not impede these reductions, but rather will ensure that further reductions will occur where they are most cost-effective.

The Commissions need only determine the appropriate level of the cap for the electric sector. The market will determine the source of emission reductions needed to achieve this cap.

47. 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?

WPTF considers that determination of the appropriate cap for the electricity sector should be limited to the question of sectoral allocation, e.g. what percentage of allowances should be distributed to the electric sector. The ultimate disposition of emission reductions and allowances between sectors – and thus the actual emission levels of each sector- will be determined by the market, based on the relative cost of GHG reductions in each sector.

The GHG analysis conducted by E3 is of no value in assessing the level of emission reductions that will be achieved within the electricity sector, because it does not analyze the impact of GHG regulation on power producers, nor the cost per ton of GHG reductions relative to other sector within the trading system.

Given these limitations, the only feasible and appropriate basis on which to make recommendations regarding the allocation of allowances to the electric sector should be equity across sectors. Specifically, WPTF considers that all capped sectors be expected to return emissions to 1990 levels by 2020. Accordingly, the Commission should recommend that the electricity sector receive an allocation equivalent to 1990 emission levels.

Modeling Issues

48. 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?

The November 9th, 2007 Administrative Law Judge ruling regarding the CPUC greenhouse gas modeling stated "The modeling effort seeks primarily to provide insights about the relative cost-effectiveness of GHG abatement measures available within the electricity sector, as well as the overall cost impacts of achieving GHG targets of varying stringency within the

2020 timeframe." While E3 has developed a user-friendly tool that is useful in evaluating the *relative* effects of different allocations schemes on Investor-Owned and Public Utilities, it is of no value in assessing the absolute cost and rate impacts of a multi-sector GHG trading scheme, the cost-effectiveness of GHG trading relative to regulatory approaches nor the impacts on independent power producers. For this reason, WPTF considers the applicability of the GHG Calculator as a tool for evaluating alternative policy options to be extremely limited. Our rationale for this conclusion is provided below.

- Because the GHG Calculator treats the carbon price as exogenous, it can not be used to reliably estimate the overall costs that will be incurred by customers and suppliers in the electric sector under a cap and trade program, nor the level of emission reductions that will be achieved. For this reason, the Calculator is of no value in assessing the costs or cost-effectiveness of GHG reductions in the electric sector relative to other capped sectors.

- The GHG calculator does not support comparison of a GHG trading system to regulatory approaches for GHG reduction within the electric sector, and thus can not be used to assess the cost effectiveness of GHG trading relative to other approaches. The calculator's gas build-out cases scenario may have been intended to allow for comparison of costs between GHG trading and the regulatory approach incorporated in the reference case scenario. However, in our experience with the model, the levels of renewable investment in the gas build-out scenario are much higher than one would expect under a true business-as-usual case. In addition, because the Calculator uses highly simplified generation supply curves, its estimates of the carbon price needed to achieve GHG reduction targets, particularly through displacement of coal generation, should be viewed with caution. Using more complex, sophisticated, commercially available tools that dispatch specific generators instead of using approximations would provide more reliable results.

- The GHG Calculator can not be used to assess options for distributing any auction revenue other than returning revenues to LSEs. The calculator simply assumes that all auction revenues accrue to retail providers and is used to reduce consumer rates.

- The GHG Calculator does not automatically substitute low carbon resources for high carbon resources in response to an increase in the price of carbon, which is one way to determine whether a GHG trading scheme would be cost-effective. Instead, the user is required to manually add renewable resources and remove high carbon resources. As a result, there is no verifiable, easily replicable way to determine a level at which RPS begins to make economic sense based on the marginal value of carbon.

- WPTF found two apparent errors in the GHG calculator that limited its usefulness and our confidence in the results. We discovered these errors when we noticed the cost of meeting load in the E3 gas build-out scenario was higher than the cost of meeting load in the reference case if we used assumptions for Energy Efficiency (EE) and Demand Response (DR) that matched the reference case. Correcting them led to results that were consistent with our expectations of lower overall cost in the gas build-out scenario. One of the apparent errors is the large number of cell references in the RefCase tab that point to the UserCase tab but probably should not. The other apparent error is cells in the RefCase tab that describe the reference case supply curve. We don't think this supply curve should change when the user case assumptions for loads, resources, energy efficiency and demand response change.

49. 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.

WPTF has strong concerns with the model's extreme assumptions regarding the market clearing price effect of carbon, and the related treatment of allowance value in producer revenues. As a result, the model greatly overestimates the producer surplus and the overall utility cost and rate impacts of GHG trading.

The E3 calculator uses two metrics to quantify the effect of carbon on wholesale electricity market prices and on profits of independent power producers. The MCP Cost Increase, stated simply, is a measure of the difference between the E3 calculator's estimate of the impact of carbon on market clearing prices, and its estimate of suppliers' carbon costs. The Producer Surplus represents the combined effect of the MCP Cost Increase and any additional value unspecified suppliers receive through administrative allocation. Both the MCP and Producer Surplus are applied only to power sold through California power pools - they are not applied to contracted power or to utility owned assets.

In calculating the MCP increase and producer surplus, the GHG calculator assumes that all generation currently under contract will be procured instead from the market upon expiration of the contract, with the result that forward contracted energy decreases by 31,500 GW or 18% by 2020 under the E3 scenarios. WPTF considers this assumption patently unrealistic. When these long-term contracts are replaced with new forward contracts, it is unlikely that buyers will allow the suppliers to receive the marginal price for carbon and also keep any allowances they were allocated. Suppliers will either have to effectively surrender their allowances or accept a price that does not include the cost of carbon. Even when they agree to surrender their allowances, contract prices may only reflect the supplier's cost of carbon based on emissions from its resources rather than the higher, marginal cost of carbon that reflects emissions from the dirtiest resource.

This argument is supported by an analysis conducted by Resources for the Future (RFF)[5] of the Regional Greenhouse Gas Initiative. In response to an earlier RFF paper[6], which concluded that direct allocation results in an increase in asset value for generators, the later paper finds:

> "The study by Burtraw, Palmer, and Kahn is built on a model of efficient electricity markets to determine wholesale electricity prices. In practice, however, electricity markets may not behave as characterized in the study. One primary reason is the existence of long-term contracts between electricity generators and distribution companies that may prohibit electricity prices from adjusting to accommodate the cost of compliance with the RGGI policy as predicted by the model. In that case, the predictions in the study about changes in electricity prices and the effect on consumers and producers of a greenhouse gas policy will be incorrect. If long-term contracts constrain the change in wholesale electricity prices, then the price effect of the policy will be less than forecast in the study. While this result is relevant to the industry in general, it is especially important to those individual facilities affected by these contracts, especially those that also face an increase in costs because of their emissions of CO_2."

Further, a large proportion of the revenue from the MCP increase will accrue to low and zero-emission resources – not fossil generators. In E3's 2020 reference case, approximately 39% of the pooled resources are zero-emission resource (Figure 1). Although energy bought from the pool includes a significant share of gas-fired generation, the zero and low-emissions resources in the pool receive a much higher margin under an MCP Cost Impact presumption given their significantly lower (or zero) carbon costs relative to those of gas facilities. This means that zero- and low- emission resources receive the biggest gain from the increase in the marginal clearing price of power due to the GHG trading system. In figure 2, WPTF calculated the percentage of contribution to the MCP Cost Impact in the year 2020 by resource type. It shows that gas-fired

[5] Wilson, Nathan, Karen Palmer, and Dallas Burtraw. 2005. "The Impact of Long-Term Generation Contracts on Valuation of Electricity Generating Assets under the Regional Greenhouse Gas Initiative" Discussion Paper 05-37. Washington, DC: Resources for the Future.

[6] This paper was appended to the April 16th Staff paper on Options for Allocation of GHG Allowances in the Electricity Sector.

facilities contribute to only 5% of the MCP Cost Impact, and that zero- or low-emission resources make up the great majority (95%) of the impact. These resources also receive nearly all of the producer surplus of the MCP Cost Impact and will not be affected by the allocation scheme, as these generators would not need to surrender allowances to cover emissions.

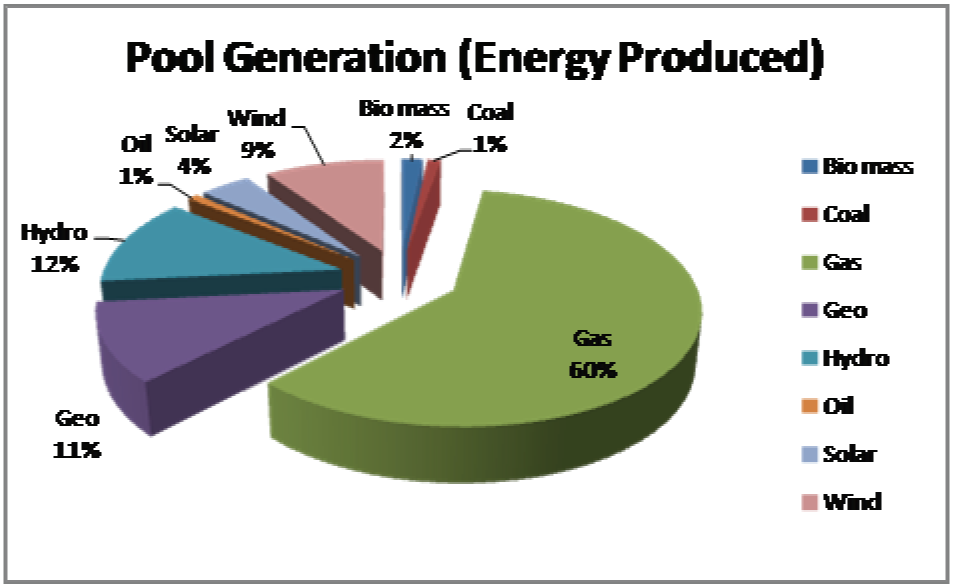

Figure 1.

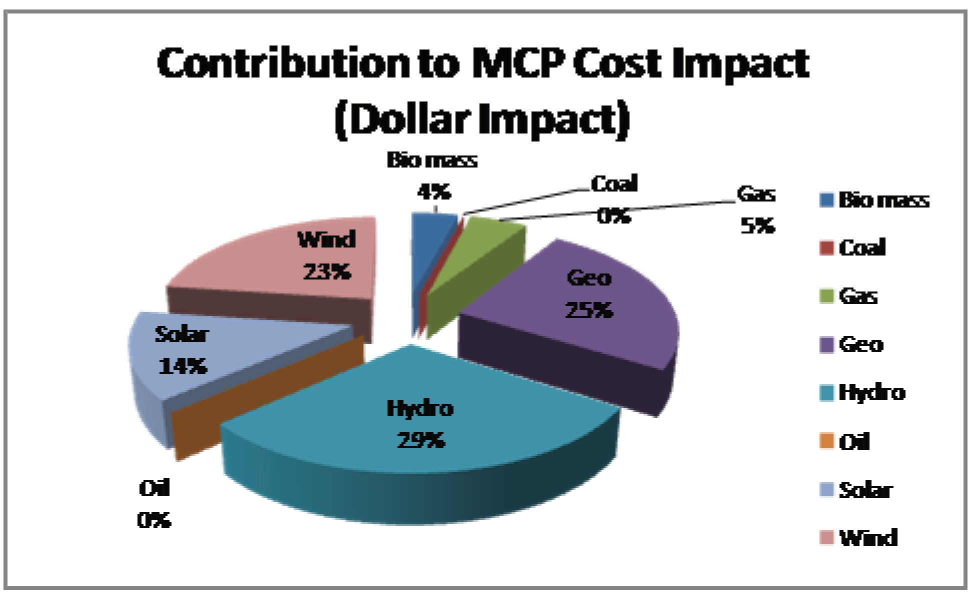

Figure 2

These simple analysis results indicate several important points about the MCP Cost Impact and related producer surplus. First, for all practical purposes, owners of non-utility fossil-fired generators are not profiting from the MCP Cost Impact. Second, the MCP Cost Impact as represented in the E3 calculator likely overstates the MCP Cost Impact significantly by assigning zero- or low-emissions resources to the pool that are already owned or under contract to an LSE. To the best of our knowledge there are few merchant renewable facilities in California that are not already either selling their output to a LSE under long-term contract or owned by an LSE. Most likely these facilities are assigned to the pool because many of them are relatively small so they were not mapped to their appropriate LSE. To the extent this is the case, and if the units are properly be mapped to their respective LSEs, the MCP Cost Impact would nearly vanish (be approximately 5% of that shown by E3, according to Figure 2) because the gas plants that are believed to actually make up the bulk of the pool have actual emissions costs that are close to those of the marginal pool unit.

Based on the above, WPTF strongly encourages the CPUC to either disregard the MCP Cost Impacts in their policy assessment, recalculate the MCP Cost Impact with proper pool information, or essentially detune the MCP Cost Impact in any E3 Calculator assessments by adjusting how much of the MPC Cost Impact gets included in the carbon cost in any calculator assessments. Moreover, we caution the CPUC regarding qualitative assessments that rely on the MCP Cost Impact, Producer Surplus or concepts of windfall profit given what seems to be fundamental misrepresentations of the MCP Cost Impact.

WPTF thanks the Commission for its attention to these comments.

Respectfully submitted,

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APPENDIX A

Documentation of WPTF Alternative Modeling Scenario

As discussed in the response to question 11, WPTF ran an alternative allocation scenario based on E3's Case 1 (the pure historic allocation approach). The WPTF scenario used an initial auction percentage of 25%, and increased this by 10% annually.

The values in row 22, columns C through L, were calculated by reference to information in the UserCase tab. These cells apparently describe a generation supply curve that adjusts certain costs in the reference case based on load and the amount of renewable resources, energy efficiency and demand response in the reference case. The values in these cells were changing with every change in the user case, which we don't think is correct. Instead, we believe these values should be held constant across all scenarios so we have fixed them at the same values that appear in the reference case as follows:

Cell	Value
C22	103.662%
D22	103.482%
E22	103.440%
F22	103.399%
G22	103.358%
H22	103.319%
I22	103.281%
J22	103.243%
K22	103.207%
L22	103.171%

Many of the intermediate calculation formulas in the remainder of the RefCase tab contain references to cells in the UserCase tab that describe the supply curve for the user case. We believe this is an inadvertent error. To correct it, we have changed every reference where a formula in the RefCase tab points to a cell in the UserCase tab so that those formulas point to the proper cells in the RefCase tab.

We verified that these changes worked as we thought they should by performing several tests. First, we re-ran the reference case and obtained results that were identical to results obtained from an unaltered version of the E3 calculator. Second, we re-ran the E3 gas build-out case. Whereas in *without* our changes, revenue requirements in 2020 *increased* with lower levels of RPS, *with* our changes revenue requirements in 2020 decreased by about $940 million, which is consistent with our expectations.

WPTF's changes to E3 Case 1

As shown in the accompanying Scenario Documentation worksheet, WPTF made the following changes to E3's Case 1:

- Set the fraction of allowances that are administratively allocated to 75% in 2012 and decreased that amount by 10% in each subsequent year so that the fraction of allowances that are allocated becomes 5% in 2019 and zero in 2020. This means the fraction of allowances that are auctioned starts off at 25% in 2012 and grows to 100% by 2020.

Year	**Percent of CO2 Allowances Auctioned**
2012	25
2013	35
2014	45
2015	55
2016	65
2017	75
2018	85
2019	95
2020	100

- Set the fraction of auction revenues that are returned to LSEs to 100% in all years.

APPENDIX B

GHG CALCULATOR SCENARIO DOCUMENTATION

Instructions: The cells in this tab will automatically populate with the key input and output data for a scenario that is loaded and saved in this GHG Calculator tool. To load and save a scenario in the tool, make changes to the yellow cells of the tabs i

USER DEFINED SCENARIO: KEY OUTPUTS, PG. 1 **Scenario Name:** Case 1 + 25% Auction w/10% step-up, return ARR
Party Name and Scenario Number: Western Power Trading Forum

Greenhouse gas emissions summary information

MMT CO2e	California	Total Offsets	Non-CA WECC	Total
2020 User Case	108.2	0.0	327	435
2020 Reference Case	108.2	n/a	327	435

Summary of change in electricity sector average rates & costs

Change in 2020 rates relative to reference case ($/kWh)	$ 0.002
% change in 2020 rates relative to reference case	1.5%
% change in 2020 rates relative to 2008	14.8%
Change in 2020 utility cost relative to reference case ($M)	$ 716
Change in 2020 utility cost relative to 2008 ($M)	$ 11,894

USER DEFINED SCENARIO: KEY INPUTS

Loads

Change in annual growth rate from ref. case	0.0%

Energy Efficiency

Electricity energy efficiency (EE) scenario	1	1= Reference case, 2=low goals case, 3=mid goals case, 4=high goals case
Natural gas energy efficiency scenario	1	1= Reference case, 2=low goals case, 3=mid goals case, 4=high goals case
% change in EE achieved from selected scenario	100%	

% change in levelized total resource cost (TRC)		% change in levelized utility program costs	
Huffman Bill	100%	Huffman Bill	100%
Title 24 + Federal Standards	100%	Title 24 + Federal Standards	100%
BBEES	100%	BBEES	100%
IOU Programs - Electric	100%	IOU Programs - Electric	100%

% change in gas EE achieved from selected scenario	100%
% change in gas levelized total resource cost (TRC)	100%
% change in gas levelized utility program costs	100%

Demand Response

Demand Response

PG&E	SCE	SDG&E	SMUD	LADWP	N.CA Other	S.CA Other	Water Agencies
5%	5%	5%	5%	5%	5%	5%	0%

Rooftop Photovoltaics

CA rooftop solar PV: 2020 nameplate installed MW	847

Combined Heat and Power

	<5 MW	>5 MW
Combined Heat and Power (CHP) new capacity	0	0

CHP receives thermal credit	FALSE
Boiler efficiency	0.8

Grid Connected CHP Characteristics

	<5 MW	>5 MW
Installed Capital Cost $/kW ($2008)	1952	1259
Gross Heat Rate	9700	9220
Electric sector share of CHP emissions	0.6	0.7
On-site share of electricity usage	1.0	0.3
Capacity Factor	0.4	0.9
Coincidence Factor	0.6	1.0
Electric Emissions Intensity (tonnes/MWh)	0.3	0.3

CHP Time of Use (TOU) shares, Operating Hours

	<5 MW	>5 MW
SHLH	2098	2098
SLLH	1574	1574
WHLH	2907	2907
WLLH	2181	2181

Utility Incentives for Onsite CHP ($/kW-yr)

	PG&E	SCE	SDG&E	SMUD	LADWP	N.CA Other	S.CA Other	Water Agencies
<5 MW	0	0	0	0	0	0	0	0
>5 MW	0	0	0	0	0	0	0	0

Utility Capacity Payments for Export CHP ($/kW-yr)

	PG&E	SCE	SDG&E	SMUD	LADWP	N.CA Other	S.CA Other	Water Agencies
<5 MW	0	0	0	0	0	0	0	0
>5 MW	92	92	92	92	92	92	92	92

New Renewable Resources & New Non-Renewable Resources

Renewable resources by transmission cluster

Alberta	0
Arizona-Southern Nevada	0
Bay Delta	0
British Columbia	0
CA - Distributed	0
CFE	0
Colorado	0
Geysers/Lake	0
Imperial	2339
Mono/Inyo	0
Montana	0
NE NV	0
New Mexico	0
Northeast CA	0
Northwest	0
Reno Area/Dixie Valley	0
Riverside	0
San Bernardino	0
San Diego	0
Santa Barbara	0
South Central Nevada	0
Tehachapi	4394
Utah-Southern Idaho	0
Wyoming	0

	Coal IGCC	Coal IGCC with CCS	Coal ST	Gas CCCT	Gas CT	Hydro - Large	Nuclear
User entered MW	0	0	0	2311	3410	0	0
PG&E	30%	30%	30%	30%	30%	30%	30%
SCE	37%	37%	37%	37%	37%	37%	37%
SDG&E	8%	8%	8%	8%	8%	8%	8%
SMUD	5%	5%	5%	5%	5%	5%	5%
LADWP	10%	10%	10%	10%	10%	10%	10%
NorCal	5%	5%	5%	5%	5%	5%	5%
SoCal	5%	5%	5%	5%	5%	5%	5%
Water Agencies	0%	0%	0%	0%	0%	0%	0%

Year to hit RPS Target: 1

RPS Ramp	Year Index
2012	1
2013	2
2014	3
2015	4
2016	5
2017	6
2018	7
2019	8
2020	9

	Not Used	Not Used	Not Used	Not Used
User entered MW	0	0	0	0
PG&E	0%	0%	0%	0%
SCE	0%	0%	0%	0%
SDG&E	0%	0%	0%	0%
SMUD	0%	0%	0%	0%
LADWP	0%	0%	0%	0%
NorCal	0%	0%	0%	0%
SoCal	0%	0%	0%	0%
Water Agencies	0%	0%	0%	0%

New Resources Key Assumptions: Capital Cost and Operating Assumptions (Continued on Next Page)

Biogas	Biomass	Geothermal	Hydro - Small	Solar Therma	Wind	Not Used	Not Used

Heat Rate (BTU/kWh)	11566	15509	0	0	0	0	0	0
Capital Costs (WECC Average) 2008$/kW	2554	3737	3011	2402	2696	1931	0	0
Tax Credits in Use? (1=Yes, 0=No)	1	1	1	1	1	1	0	0
Capacity Factor	85%	85%	90%	50%	40%	37%	100%	100%
On-Peak Capacity Contribution	100%	100%	100%	65%	85%	20%	100%	100%

USER DEFINED SCENARIO: KEY INPUTS, PG. 2 **Scenario Name:** Case 1 + 25% Auction w/10% step-up, return ARR
Party Name and Scenario Number: Western Power Trading Forum

New Resources Key Assumptions: Capital Cost and Operating Assumptions (Continued)

	Not Used	Coal IGCC	Coal IGCC wi	Coal ST	Gas CCCT	Gas CT	Hydro - Large	Nuclear
Heat Rate (BTU/kWh)	0	8309	9713	8844	6917	10807	0	10400
Capital Costs (WECC Average) 2008$/kW	0	2388	3418	2066	813	735	2402	3333
Tax Credits in Use? (1=Yes, 0=No)	0	1	1	1	1	1	1	1
Capacity Factor	100%	85%	85%	85%	90%	5%	50%	85%
On-Peak Capacity Contribution	100%	100%	100%	100%	100%	100%	90%	100%

Fuel Prices

	Gas in CA	Coal in WY
Fuel price in 2020 ($2008/MMBTU)	$ 7.85	$ 1.01

CO2 Market

Price for Emissions Permits	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Price for permits ($/tonne CO2e)	$ 30.00								$ 30.00
Administrative allocation									
Percent of permits administratively allocated	75%	65%	55%	45%	35%	25%	5%	0%	0%
Percent of permits auctioned	25%	35%	45%	55%	65%	75%	95%	100%	100%
Basis of allocation									
Energy Output (updated yearly)	0%	0%	0%	0%	0%	0%	0%	0%	0%
Historic 2008 emissions	100%	100%	100%	100%	100%	100%	100%	100%	100%

Basis of energy output allocation: 1
1 = Use all GWh for output-based allocations
2 = Exclude non-fossil GWh from output-based allocations

% of CO2 cost reflected in MCP under output-based allocation: 100%

Offsets Price ($/tonne CO2e)	2012	2013	2014	2015	2016	2017	2018	2019	2020
California offsets	$ -								$ -
Regional offsets	$ -								$ -
International offsets	$ -								$ -
Maximum % of emissions requirement that can be met with offsets									
California offsets	0%								0%
Regional offsets	0%								0%
International offsets	0%								0%

Auction Revenue Redistribution to LSEs	2012	2013	2014	2015	2016	2017	2018	2019	2020
Percent of auction revenue returned to LSEs	100%	100%	100%	100%	100%	100%	100%	100%	100%
Method for Returning Revenues									
Return based on LSE Sales (updated yearly)	0%	0%	0%	0%	0%	0%	0%	0%	0%
Return based on 2008 emissions	100%	100%	100%	100%	100%	100%	100%	100%	100%

Scope of auction revenue return: 1
1 = Constant Auction Return (Default Assumption)
2 = Sector-Only Auction Return (Alternative Scenario)

Imported Power and out-of-state bilateral contracts between generators and LSEs

Deemed CO2 emissions intensity for imported electricity

Unspecified imports emissions intensity

	lbs/MWh
Northern	1100
Southern	1100

Emissions intensity of previously unspecified imports, that become specified

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Northern	1100								1100
Southern	1100								1100

Percentage of previously unspecified imports that become specified, at the emissions intensity chosen above

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Northern	0%								0%
Southern	0%								0%

Assumptions about LSE contracts with out of state fossil-fuel generators

Existing contracts: 2
2 = Continue to honor contracts, regardless of economics (reference case assumption)
1 = Eliminate contracts if not economic, including price of emission permits (alternative scenario)

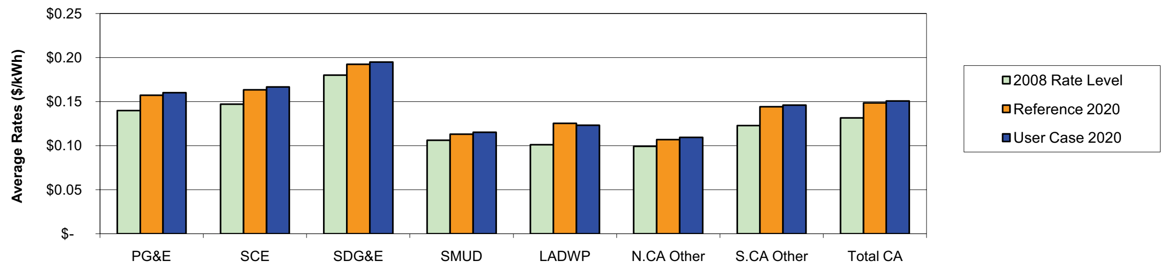
Contract expiration: 2
2 = Generator sells to the power pool after bilateral contract ends (reference case assumption)
1 = Assume renewal of contract ownership (alternative scenario)

Expiration dates of major LSE contracts or ownership shares with coal generators

	Date
Boardman 1	12/31/2013
Bonanza 1	12/31/2009
Four Corners 4	12/31/2020
Four Corners 5	12/31/2020
Hunter 2	12/31/2009
Intermountain 1	12/31/2020
Intermountain 2	12/31/2020
Navajo 1	12/31/2019
Navajo 2	12/31/2019
Navajo 3	12/31/2019
Reid Gardner 4	12/31/2013
San Juan 3	12/31/2020
San Juan 4	12/31/2020

USER DEFINED SCENARIO: KEY OUTPUTS, PG. 3 **Scenario Name:** Case 1 + 25% Auction w/10% step-up, return ARR
Party Name and Scenario Number: Western Power Trading Forum

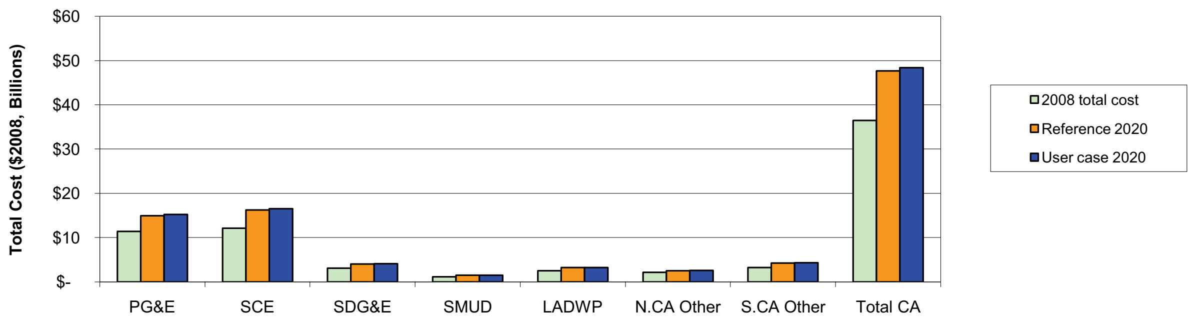
Comparison of 2008 and 2020 Rates



Impact on Rates

	PG&E	SCE	SDG&E	SMUD	LADWP	N.CA Other	S.CA Other	Total CA
2008 Rate Level	$ 0.14	$ 0.15	$ 0.18	$ 0.11	$ 0.10	$ 0.10	$ 0.12	$ 0.13
Reference 2020	$ 0.16	$ 0.16	$ 0.19	$ 0.11	$ 0.13	$ 0.11	$ 0.14	$ 0.15
User Case 2020	$ 0.16	$ 0.17	$ 0.19	$ 0.12	$ 0.12	$ 0.11	$ 0.15	$ 0.15
Change 2020 User to Reference	1.8%	1.9%	1.3%	2.1%	-2%	2.1%	1.4%	1.5%
Change 2008 to 2020 User Case	14%	13%	8%	9%	22%	10%	19%	15%

Comparison of 2008 and 2020 Total Cost



Impact on Cost

	PG&E	SCE	SDG&E	SMUD	LADWP	N.CA Other	S.CA Other	Total CA
2008 total cost	$ 11,374	$ 12,108	$ 3,141	$ 1,184	$ 2,492	$ 2,138	$ 3,285	$ 36,462
Reference 2020	$ 14,936	$ 16,231	$ 4,068	$ 1,485	$ 3,266	$ 2,563	$ 4,266	$ 47,639
User case 2020	$ 15,207	$ 16,542	$ 4,119	$ 1,516	$ 3,216	$ 2,617	$ 4,325	$ 48,355
Change 2020 User to Reference	1.8%	1.9%	1.3%	2.1%	-1.5%	2.1%	1.4%	1.5%
Change 2008 to 2020 User Case	34%	37%	31%	28%	29%	22%	32%	33%

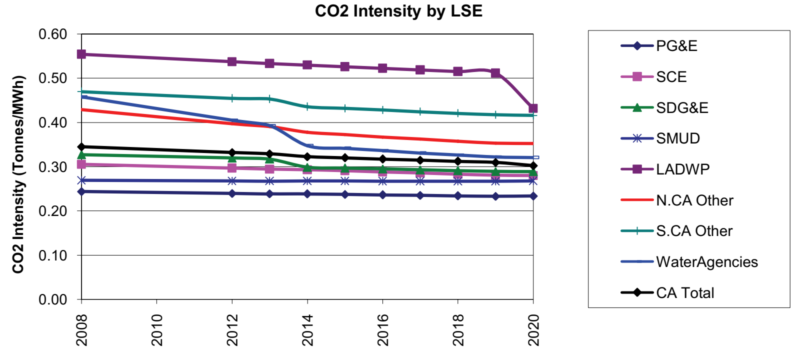
2020 Producer Surplus ($M)

	PG&E	SCE	SDG&E	SMUD	LADWP	N.CA Other	S.CA Other	WaterAgenci	Total CA
2020	$ 197.01	$ 231.91	$ 40.02	$ 15.10	$ 35.10	$ 82.47	$ 69.87	$ 44.75	$ 716.22

Greenhouse Gas Emissions Intensity (tonnes CO2/MWh)

	PG&E	SCE	SDG&E	SMUD	LADWP	N.CA Other	S.CA Other	WaterAgenci	CA Total
2008	0.24	0.31	0.33	0.27	0.55	0.43	0.47	0.46	0.34
2012	0.24	0.30	0.32	0.27	0.54	0.40	0.45	0.40	0.33
2013	0.24	0.29	0.32	0.27	0.53	0.39	0.45	0.39	0.33
2014	0.24	0.29	0.30	0.27	0.53	0.38	0.44	0.35	0.32
2015	0.24	0.29	0.30	0.27	0.53	0.37	0.43	0.34	0.32
2016	0.24	0.29	0.29	0.27	0.52	0.37	0.43	0.34	0.32
2017	0.24	0.29	0.29	0.27	0.52	0.36	0.42	0.33	0.31
2018	0.23	0.28	0.29	0.27	0.52	0.36	0.42	0.33	0.31
2019	0.23	0.28	0.29	0.27	0.51	0.35	0.42	0.32	0.31
2020	0.23	0.28	0.29	0.27	0.43	0.35	0.42	0.32	0.30

CO2 Intensity by LSE



<u>**CERTIFICATE OF SERVICE**</u>

I hereby certify that I have this day served a copy of the ***Comments of the Western Power Trading Forum on Design of Greenhouse Gas Regulatory Strategies*** on all parties of record in proceeding ***R.06-04-009*** by serving an electronic copy on their email addresses of record and by mailing a properly addressed copy by first-class mail with postage prepaid to each party for whom an email address is not available.

Executed on June 2, 2008, at Woodland Hills, California.

Michelle Dangott

Michelle Dangott

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A.06-04-009

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