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

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

**BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT
COMMISSION OF THE STATE OF CALIFORNIA**

In the Matter of: Order Instituting Informational Proceeding on a Greenhouse Gas Emissions Cap	Docket 07-OIIP-01

NORTHERN CALIFORNIA POWER AGENCY COMMENTS ON ASSIGNED ADMINISTRATIVE LAW JUDGES' RULINGS AND STAFF PAPERS REGARDING RECOMMENDATIONS TO THE CALIFORNIA AIR RESOURCES BOARD FOR THE ELECTRICITY SECTOR

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TABLE OF CONTENTS

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In accordance with Rules of Practice and Procedure of the California Public Utilities Commission (CPUC), and the direction set forth in the April 16, 2008 *Administrative Law Judges' (ALJ) Ruling Updating Proceeding Schedule and Requesting Comments on Emission Allowance Allocation Policies and Other Issues* (April 16 Ruling) and the May 20, 2008 *ALJs' Ruling Modifying Schedule and Correcting Suggested Outline for Comments* (May 20 Ruling), the Northern California Power Agency[1] (NCPA) submits these comments[2] on the questions

[1] NCPA is a Joint Powers Agency whose members include the cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville, Santa Clara, and Ukiah, as well as the Bay Area Rapid Transit District, Port of Oakland, the Truckee Donner Public Utility District, and the Turlock Irrigation District, and whose Associate Members are the Plumas-Sierra Rural Electric Cooperative, and the Placer County Water Agency.

presented in the April 16 Ruling, the *Joint CPUC and California Energy Commission (CEC) Staff paper on Options for Allocation of GHG Allowances in the Electricity Sector* (Allocation Staff Paper), the May 1, 2008 *ALJs' Ruling Requesting Comments on Combined Heat and Power Policies* (May 1 Ruling), the *Joint Staff Paper on GHG Regulation for Combined Heat and Power* (CHP Staff Paper), the May 6, 2008 *ALJs' Ruling Requesting Comments on Flexible Compliance Policies* (May 6 Ruling), and the May 13, 2008 *ALJ s' Ruling Requesting Comments on Emission Reduction Measures, Modeling Results, and Other Issues, etc*., (May 13 Ruling). Each of these rulings seeks additional information for the CPUC and CEC to base a recommendation to the California Air Resources Board (CARB) on the treatment of greenhouse gas (GHG) emissions for the electricity sector in a cap-and-trade program. In these comments, the CPUC and CEC are collectively referred to as the "Joint Commissions." [3]

INTRODUCTION

A. Implementation of Assembly Bill 32 is an Ongoing, Statewide Effort.

Since the inception of these proceedings, NCPA has worked with the Joint Commissions, CARB, and the Western Climate Initiative (WCI) toward the common goal of developing an implementation plan for Assembly Bill (AB) 32 that not only meets the clearly stated criteria of AB32, but that is also workable, practicable, reduces administrative burdens, and maintains California's position as a leader in the development of GHG reduction measures. NCPA looks forward to continuing that effort through these comments to the Joint Commissions and in continuing deliberations at CARB following the issuance of that agency's Scoping Plan. NCPA also supports the efforts of the WCI – of which California is an integral member – and looks forward to further working with WCI in the development of a regional program the State can participate in.

The Scoping Plan, which CARB is required to adopt by January 1, 2009,[4] is only the first step, and regulations for the implementation of AB32 – which will include the details necessary

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[2] Consistent with the direction set forth in the ALJ Ruling, these comments are jointly filed with the CPUC in R.06-04-009 and the CEC Docket 07-OIIP-01.

[3] To the greatest extent possible, these Comments utilize the Suggested Outline set forth in the May 13 Ruling, as corrected by the May 20 Ruling. For specific questions or attachments that are not addressed in this filing, NCPA takes not position on those issues at this time, but reserves the right to address them in reply comments.

[4] Health & Safety Code § 38561.

to actually implement AB32, is not required until January 1, 2011.[5] Since CARB has already acknowledged that its Scoping Plan – by necessity – will not include the level of detail that was originally contemplated, the Joint Commissions should not rush to make recommendations on the structure of a cap-and-trade program until such time as a record has been fully and thoroughly developed.

B. Summer 2008 Recommendations to CARB Should be Preliminary.

The Joint Commissions should submit a *preliminary* recommendation to CARB, based on the information sought in the multiple ALJ Rulings, for items that warrant inclusion in the Scoping Plan for further consideration and development as AB32 is implemented. In March 2008, the CPUC and CEC each approved, by unanimous votes, the *Interim Opinion on Greenhouse Gas Regulatory Strategies* (March 2008 Interim Opinion). (CPUC, D.08-03-018, March 13, 2008, CEC-100-2008-002-F, March 12, 2008.) In the March 2008 Interim Opinion, the Joint Commissions acknowledged that the greatest amount of emissions reductions would come from existing and expanding regulation and programs that focus on measures such as energy efficiency, renewable energy, emissions performance standards, and building codes. The March 2008 Interim Opinion also recommended that CARB adopt a deliverer point of regulation for the electricity sector, and further recommended that a multi-sector cap-and-trade program be adopted that would include the electricity sector. Since the record in this proceeding did not contain sufficient details regarding several aspects of a cap-and-trade program, including treatment of issues such as allocation of allowances under a deliverer point of regulation, treatment of offsets and other flexible compliance mechanisms, and the role of combined heat and power within a capped electricity sector,[6] the March 2008 Interim Opinion noted that the Joint Commissions would be asking the parties for more information upon which to base a recommendation to CARB.[7]

That information request came in the form of the four separate ALJ Rulings referenced above. Together, the ALJ Rulings seek party input and comments on more than 81 specific inquiries, two separate staff papers, and 28 presentations and attachments. All of the information

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[5] Cal. Health & Safety Code § 38562 (a).

[6] D.08-03-018, p. 99.

[7] D.08-03-018, p. 101.

sought relates to salient issues that must be addressed before the state can adopt regulations for the implementation of a cap-and-trade program. However, even with the extension granted by the Assigned ALJs,[8] the Joint Commissions seek a vast amount of information. Furthermore, the level of detail that parties are able to provide at this preliminary stage of development of a cap-and-trade program is necessarily limited, and should be viewed by the Joint Commissions as conceptual, at best. The Joint Commissions' recommendation to CARB on all issues regarding a cap-and-trade program should be moderated by the principle that the state should be rushing to implement a hastily structured program. CARB staff has recognized that it will take years to work out a cap-and-trade program because it is necessarily complex.[9] Indeed, Chairwoman Nichols even noted during a recent Senate hearing on cap-and-trade and AB32 implementation, that the state has four years to figure out how to work a market-based program.[10] Not only the electricity sector, but all capped sectors, as well as the State's consumers, would be well served by using the entire time allotted by the Legislature to fully vet all issues associated with the development of a multi-sector cap-and-trade program.

C. The Joint Commissions Should Recommend a Specific GHG Emissions Reduction Level for the Electricity Sector.

In order to accurately determine the actual emissions reductions that entities within the electricity sector with a compliance obligation – namely the deliverers – are required to make, it is imperative that the Joint Commissions include in their recommendation to CARB a proposal for the total GHG reductions that the electricity sector will be called upon to make. Further deliberations will then be necessary to be certain that each deliverer within the sector is informed of its individual compliance obligation.

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8 ALJs TerKeurst and Lakritz Ruling Modifying Schedule and Correcting Suggested Outline for Comments, May 20, 2008.

9 Oral comments by CARB Staff during the AB32 – California Global Warming Solutions Act, Scoping Plan Workshop Series – Policy Scenarios, May 19, 2008 (May 19 CARB Workshop).

10 Senate Energy, Utilities and Communications Committee, Information Hearing, AB32 Implementation: Understanding a Cap and Trade System, May 21, 2008.

I. SUMMARY

A. Development of a Cap-and-Trade Program Should be Carefully Considered.

In order to meet the mandates of AB32 to achieve cost-effective,[11] real reductions in GHG emissions, *and* to ensure that California's electric customers continue to receive reliable and competitively priced electric service, the focus of a California-only emissions reduction program for the electricity sector must be on the regulatory reductions highlighted in D.08-03-018. Indeed, even before CARB can consider implementing a market based program, there are several requirements that must be met.[12] The May 2 CARB-hosted workshop,[13] featured a wide range of existing programs and policies that achieve real reductions through non-market mechanisms (see May 13 Ruling). In light of the conclusions reached in D.08-03-018, and the information presented during that workshop, the primary emphasis in the electricity sector should be on achieving GHG emissions reductions through non-market mechanisms.

The April 16 Ruling and Allocation Staff Paper address various options regarding the distribution of emissions allowances and allowance values in a presumed cap-and-trade program. The March 2008 Interim Opinion addresses the means by which the agencies foresee the majority of the emissions reductions being accomplished – that is through aggressive energy efficiency and renewable energy programs, as well as other direct regulatory approaches that seek to reduce not only overall electric load, but the total amount of electricity procured from GHG emitting resources.[14] CARB has acknowledged that the majority – approximately 60% – of the total reductions statewide will occur through "core measures,"[15] the majority of which will come from the transportation and electricity sectors. Even at this juncture, the State's regulatory bodies have already amassed enough information to confirm that any cap-and-trade program will

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11 Consideration of cost-effectiveness must take into account the impacts that any AB32 implementation measures have on an individual sector. For example, the fact that the electricity sector has already developed the means to launch energy savings programs through aggressive energy efficiency should not result in requiring the electricity sector to bear the burden of reductions for other sectors, merely because those sectors have yet to create their own emissions reductions programs and will need to incur "start-up costs" associated with doing so.
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12 Cal. Health & Safety Code § 38562(c).

13 Climate Action Team Energy Subgroup Workshop on Emissions Reduction Measures, May 2, 2008.

14 See D.08-03-018, pp. 36, 39.

15 May 19 CARB Workshop, Workshop presentation, Slide 13, Draft Scoping Plan: Core Measures.

not account for the majority of the emissions reductions – and likely even fewer than 40% of the total reductions in the electricity sector. Accordingly, it is with great care that the Joint Commissions should move forward in making firm and finite recommendations in an untested and unproven area. As set forth more fully below, the development of a cap-and-trade program to facilitate achieving the remaining reductions should be carefully considered, and each of the issues raised by the stakeholders and those addressed in these comments must be fully addressed.

B. Auctions Should Not be Recommended for the Electricity Sector Until the Structural Details Have Been Fully Vetted.

Auctions should not be utilized until the market has fully matured, and no recommendations regarding an auction should be finalized until details regarding the structure of the auction have been fully vetted, including ways in which to mitigate potential market manipulation. Allowances should be freely allocated to the entities with the compliance obligation, and likewise, the values associated with allowances should be returned directly to the retail electric providers for the benefit of the electricity customers that have borne those costs. Retail providers would best utilize the allowance values (1) to ensure the continued reliable delivery of electricity to the State's residents and businesses; (2) to expand upon the energy efficiency portfolio of programs that is essential to effecting real, long-term emissions reductions, (3) to expand upon existing renewable programs; and/or promote new technology solutions; (4) as well as offer much needed rate relief to those customers that will be the most adversely impacted by the costs associated with implementation of AB32.

C. Any Market For Allowances Must Be Able To Meet The Operational Needs Of Generators Serving California's Electricity Customers.

Although it is not addressed in any of the four ALJ Rulings at issue here, before making a final recommendation on any allowance allocation design option, the Joint Commissions must fully and thoroughly address how each of the options would impact the ability of the State's retail providers to continue to providing reliable electric service to their customers.[16] A firm

[16] *See* Cal. Health & Safety Code §§ 38501(h) and 38561(a).

emissions cap for the electricity sector could result in an electricity shortage. With the horrors of price spikes and rolling-blackouts from 2000 and 2001 still fresh in the minds of Californians, it is imperative that the continued provision of reliable electricity be addressed.

Under a deliverer point of regulation, the compliance obligation is not necessarily tied to an obligation to serve electricity customers. As such, the actions of generators that do not have an obligation to serve customers maybe be directed by the cost of allowances, and not by the need to ensure that the "lights stay on." A true cap within the electricity sector is simply not a real option. Retail providers cannot simply "let the lights go out" if there are no allowances to be found. Because of the requirement to provide California's customers with safe and reliable electricity, there is no such thing as a firm cap for the electricity sector.

Currently, reliability in the Western Interconnect is met in real-time by maintaining an established amount of operating reserves, both spinning and non-spinning resources. This is supplemented by required planning criteria annual capacity showings of a 15% available capacity reserve margin above forecasted load. Both the real-time operating reserves and planning criteria annual capacity showings would be impacted by GHG emissions and the ability to procure allowances through the market. It is vitally important that any market for allowances be both liquid and facile enough to meet the operational needs of generators in the California Independent System Operator (ISO) markets and throughout the State.

The following hypothetical exemplifies the potential impacts of a cap on the availability of electric generation:

A large generator could be required to run at base load for much of the year, (assuming dry hydro conditions), and then by the November – December period, that generator would be unable to run because it had used all of its allowances and was not able to acquire further allowances. If that generator ceases operations until the end of the year, the end of the compliance period, or until it was able to acquire the necessary allowances at an acceptable rate, the retail providers that anticipated serving customer load with electricity produced by this generator would be unable to meet operating reserve and reserve margin requirements. This could easily place the state back into the situation experienced during the winter of 2000–2001.[17]

The ISO requires that generation used to count toward a resource adequacy requirement

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[17] Indeed, California utilities are still dealing with the ramifications of the energy crisis through protracted litigation.

be made available to the market, but pursuant to the provisions of the ISO Tariff, the generators are not required to run those units if doing so would violate operating criteria including environmental or other regulatory requirements. Clearly, the requirement to procure emissions allowances would be deemed an environmental requirement under the generators' operating criteria, which would keep the generator from being required to provide the necessary electricity in the event that it was unable to procure enough emissions allowances.

Based on the language in the most recent draft of the ISO's Business Practice Manual (BPM) and the ISO Tariff, there is no way to prevent generation from being withheld from the market. This raises a very real concern in that there is no way to prevent market participants who control large amounts of generation from deciding not to procure sufficient allowances that will allow them to run all of the time. Whether a matter of circumstance, or by design, should this occur, these generators could withhold their capacity from the market and potentially manipulate the price. There is nothing in the record to date regarding any allocation methodology or the point of regulation that addresses ways in which instances such as these may be avoided.

Even assuming an effective and efficient market for emissions allowances, it should be anticipated that price spikes will still occur. These spikes could cause the cost of energy to exceed the current market cap for energy. Depending on the availability of allowances in the secondary market, it may be very expensive to bid a resource into the California market. Additionally, under California's market design, both currently and under the proposed ISO market redesign and technology upgrade (MRTU), the market price can be set by the last incremental megawatt (MW) generated. If that last generated MW is produced from a unit that has to procure allowances at an exorbitant price, every generator bidding into the market could get paid that additional incremental cost. Accordingly, this additional cost will be passed directly onto California ratepayers.

II. GENERAL ISSUES

5/13; Q3: For any non-market-based emission reduction measures for electricity discussed in your opening comments, are there any overlap or compatibility issues with the potential electricity sector participation in a cap-and-trade program? Explain.

As noted above, the CPUC, CEC, and CARB have all acknowledged that the greatest GHG reductions will be achieved through non-market-based measures – both those already in place, and those that are further developed and implemented. If the electricity sector were also called upon to participate in a cap-and-trade program, it is important to note that such a program could actually reduce the overall reductions to be achieved through the regulatory programs. To a certain extent, the ability to trade allowances could create a disincentive to implement some reduction programs that may be more costly. If emissions allowances can be more readily purchased at auction this may drive up the costs of implementing new renewable energy or energy efficiency programs. In such a case the opportunity to create real emissions reductions would be lost, and there would be no net change in total GHG emissions. On the other hand, if regulatory programs – such as energy efficiency programs and renewable energy development (including the development of necessary transmission facilities) are made a priority, and are the only means by which to effect reductions in the nascent years of AB32 regulation, those reduction opportunities would not be lost.

> 5/13; Q11: Address any interactions among issues that you believe the Commissions should take into account in developing recommendations to ARB.

The Joint Commissions should look at a wide range of issues when developing its recommendations to CARB. Clearly, the total cost impact on electricity customers is important, but so is electricity reliability. To that end, the Joint Commissions need to ensure that the proposed point of regulation does not unduly interfere with the ability of generators to continue to operate efficient and low-emitting resources, nor the ability of retail providers to continue to provide safe and reliable electricity to California's consumers.

> 5/13; Q12: 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?

There are several important factors that the State should keep in mind in developing a cap-and-trade program in the face of pending regional and federal program development, including how facile it will be for the State's program to transition to a broader-based program, the impact of start-up costs and other administrative complexities, and the way in which the State's final recommendations on things such as allowance allocation and allowance revenue distribution impact California's position in a regional or federal program.

Although California remains a leader in addressing climate change matters, the problem is only going to be solved through global solutions. Accordingly, California's program should be developed with an eye toward being integrated into a regional and ultimately national program. One important step in this process is the State's continued participation in the WCI, which has already begun tackling the more complex issues of how a cap-and-trade program can work with different market structures. The WCI process has also provided an ideal forum for the further contemplation of offsets and other flexible compliance mechanisms that will be essential to meeting the specified reduction targets and achieving long-term reductions.

Just as importantly, the State must consider the costs associated with launching a California-only program in light of the development of regional and national programs. NCPA does not believe that the State should thwart its efforts to implement AB32 until the WCI or Congress have completed their efforts, as this would result in the loss of valuable time during which the State could be achieving significant emissions reductions. The Joint Commissions should recommend to CARB that California focus on non-market based emissions reduction programs, because these programs will continue to be useful tools for emission reductions regardless of whether the program is State-wide, regional, or federal.

Finally, the Joint Commissions must look closely at the make-up of California's electricity market in comparison to that of the rest of the country in order to determine the most effective and feasible allowance allocation and allowance revenue allocation scheme. The State would not want to find itself in a position where the allocation methodologies adopted would set a precedent for a national program that would ultimately have an adverse impact on California's electricity consumers.

> <u>5/13; Q13</u>: 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.

Simply put, there **is not** enough information in the record in this proceeding to support any detailed recommendation to CARB about the electricity sector for inclusion in the Scoping Plan for a cap-and-trade.

Despite the fact that the March 2008 Interim Opinion recommended that the electricity sector be included in a multi-sector cap-and-trade program, the record on that topic has not been fully developed with regard to the necessary elements of a cap-and-trade program. If CARB intends the Scoping Plan to be a detailed roadmap upon which to base the establishment of regulations for AB32 implementation, then there must be careful and thorough deliberations on all of the issues set forth in the various ALJ Rulings, and not merely one round of comments.[18] As noted above, while both Commissions expended considerable efforts researching these issues, as is evidenced by the sheer volume of information being sought from the parties in the four ALJs' Rulings issued over the last six weeks, the record is essentially devoid of the level of detail necessary to make any kind of reasoned recommendation to CARB at this time. It necessarily follows that other than stating its intent to continue to address the issues raised in the referenced Rulings, CARB should forgo providing detailed recommendations on implementation of a cap-and-trade program for the electricity sector in the final Scoping Plan. Instead, the agency should utilize the coming years and the time provided by the Legislature between when the Scoping Plan is to be issued and when the final regulations must be adopted to complete its due diligence with regard to these vitally important matters.

[18] AB32 requires CARB to adopt a Scoping Plan by January 1,2009 (Health & Safety code § 38561(a). While it had originally appeared that CARB intended that document to include a high level of detail regarding exactly how AB32 would be implemented, it has become increasingly clear from the discussions at the various CARB stakeholder meetings over the last two months, the Scoping Plan is not likely to be that detailed.

> 5/6; Q1(a): 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.

In Section IV, Flexible Compliance, NCPA addresses the questions set forth in the May 6 Ruling, addressing the importance of further exploring the use of flexible compliance mechanisms, including such items as offsets, multi-year compliance periods, and the banking and borrowing of emissions credits. California has been an active participant in the WCI process; the WCI Offsets Subcommittee has been very active in exploring myriad issues regarding the same inquiries set forth herein. Indeed, the questions facing the State are the very same ones currently before the WCI, and as such, the Joint Commissions should also look to that process as a valuable source of information on this important topic.

As is the case with all aspects concerning the implementation of a cap-and-trade program for the electricity sector, the issue of flexible compliance mechanisms have not been given sufficient attention or review for the Joint Commissions to make a recommendation to CARB at this time, other than to urge the agency to allow the parties ample time to research this issue. Clearly flexible compliance tools are going to play a key role in ensuring that entities meet their compliance obligations, as well as stimulate and incentivize emissions reduction research.

> 5/6; Q2: 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?

As noted above, NCPA addresses this issue in greater detail in Section IV, Flexible Compliance. One important factor that will facilitate answering these kinds of inquiries is the State's continued participation in the WCI process.

III. ALLOWANCE ALLOCATION

A. Detailed Proposal : Q1 and Q10 (4/16/08)

4/16; Q1: Please explain in detail your proposal for how GHG emission allowances should be allocated in the electricity sector.

Absent a definitive cap on the electricity sector that sets exactly the emissions reductions that the entire sector will be called upon to make,[19] NCPA supports the free distribution of allowances to electric retail providers based on their retail sales. Such a distribution would utilize the most recent historical basis beginning with information reported for 2009; this benchmark would accommodate both growth and new entrants, but would also be periodically adjusted to account for reductions accomplished through energy efficiency programs in order to acknowledge such reductions and avoid any perverse incentives not to maximize the efficiency of such programs.

Due to the concerns addressed herein regarding the utilization of an auction – especially at the beginning of AB32 implementation, NCPA's Preferred Approach does not include any transition to auction. This approach is also premised on retail providers being the point of regulation. During the early stages of AB32 implementation, it is the retail provider that will be able to effect the most immediate and permanent emissions reductions utilizing direct regulatory programs, which makes retail providers the same entities in most need of the emissions allowances. NCPA supports the use of regulatory programs promulgated at the state and local levels that result in the greatest opportunity for real and permanent GHG reductions that are not only cost-effective, but minimize the adverse impacts of AB32 compliance on retail electric customers and do not jeopardize the reliable provision of electricity across the State. In order for retail providers to achieve the greatest reductions with the least adverse impact on the State's electricity customers, the value of emissions allowances must remain with the entities that will

[19] As noted above, NCPA believes that the determination of a sector cap, followed by an entity specific cap, is necessary to make a fully informed recommendation on the means by which allowances should be allocated. Only if an entity is aware of its end-goal in terms of mandatory reductions can the entity then determine the full cost implications of the various allowance allocation schemes on the utility and its customers.

be called upon to effect the reductions – namely the retail providers. This is true regardless of the point of regulation.

NCPA acknowledges the complexities surrounding the use of a different point of regulation and the impact a different point of regulation might have on the NCPA Preferred Approach. However, the distribution of allowances to retail providers and a retail provider point of regulation will provide the most cost-effective total GHG emissions reductions and account for new market entrants. This is especially crucial during the initial stages of AB32 implementation. Such an approach also provides for technologies that will allow generators to reduce emissions at existing plants to be further employed. Until that time, existing generators will have no opportunity to reduce their GHG emissions short of reducing their total electricity output, which could jeopardize the reliable provision of electricity to the State's electricity customers.

As noted, this approach is also favorable in that it would not necessarily involve deployment of a cap-and-trade program at the establishment of AB32 implementation, and would further negate the need for an auction that would be both costly and complicated to establish.

Each of the "preferred approaches" discussed in the Allocation Staff Paper either start with an auction, or conclude with a transition to auction. As discussed above, any recommendation for an auction is problematic because of the lack of detail regarding what such an auction would look like and the likely additional costs that an auction would bring to the electricity sector. To a large extent, the State's consumers still have not seen the real costs associated with regulatory compliance obligations; once these costs are incorporated into electricity prices, compounding the impact by including the volatile costs associated with a market would surely result in rate-shock.

Such a free distribution of allowances recognizes the ongoing efforts of retail providers to reduce their carbon footprints, and also acknowledges that even those entities with lower total emissions will be called upon to implement aggressive energy efficiency and renewable energy programs. These programs will be targeted in meeting the total retail load of these providers, further strengthening the link between allocations based on retail sales.

Finally, California policy makers have repeatedly acknowledged that the implementation of AB32 should serve as a model for other governments and jurisdictions.[20] To that end, it is important that the State set a program precedent that will not harm California when a determination is made on the allocation of allowances at a national level. While a number of California customers receive power from coal-fired generation facilities under long-term and long-standing contracts, California's total resource portfolio is much less coal intensive than the rest of the nation. The Joint Commissions must take care that any recommendation made to CARB regarding allowance allocations not set a precedent that does not serve the State well in the transition to a regional or federal program, especially in light of the fact that the State is poised as a leader in setting a standard for the implementation of GHG reducing measures.

The California Electricity Sector Should Not Be Part of An Auction

Since the beginning of the discussion regarding the potential utilization of market-based mechanisms[21] several parties have raised concerns regarding the cost and market manipulation implications of using an auction in the electricity sector.[22] Nothing that has transpired as part of the State, regional, or federal consideration of these issues has provided any assurances that these concerns are unfounded. Simply put, utilization of an auction without clear provisions to return auction revenues to retail providers is nothing more than a cost-adder for the electricity sector. Still reeling from daily gasoline price increases and suggestions that these costs are being manipulated by third parties, it is clear that the State's electricity consumers have not yet absorbed what the inclusion of yet another market – this time a carbon market – might mean in terms of electricity rate impacts.[23]

The Joint Commissions noted that some level of auction should be utilized to distribute

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[20] May 19 CARB Workshop, Workshop Presentation on Policy Scenarios, Slide 5, Plan Objectives and Slide 19, Criteria for Crafting a Preferred Approach; [20] Senate Energy, Utilities and Communications Committee, Information Hearing, AB32 Implementation: Understanding a Cap and Trade System, May 21, 2008.

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

[22] See: Comments on Allocation Issues; Southern California Public Power Authority (SCPPA), October 31, 2007, p. 26; SCPPA, November 14, 2007, p. 11; Calpine, October 31, 2007, p. 2; Calpine, November 14, 2007, p. 3; Energy Producers and Users Coalition (EPUC), October 31, 2007, p. 4 (stating auctions are risky); Sacramento Municipal Utility District (SMUD), October 31, 2007, p. 6; LADWP, October 31, 2007, pp. 9-11; MID, October 31, 2007, p. 5.

[23] NCPA notes that these same concerns were voiced by Senator Christine Kehoe during the Senate Energy, Utilities and Communications Committee, Information Hearing, AB32 Implementation: Understanding a Cap and Trade System, May 21, 2008

allowances.[24] This recommendation was made without *any* analysis regarding what that auction should look like. Further, the Allocation Staff Paper specifically notes that "staff has not delved into the finer points of auction design." (Allocation Staff Paper, p. 8). The Staff Paper goes on to note that "[w]hile it is critically important to design auctions in a way to prevent collusion and abuse of market power, we expect that auction design will be undertaken later under ARB guidance, if ARB decides to explore auctions as an allocation mechanism in its scoping plan." (Id.) This statement is made despite the fact that each of the Allocation Staff Paper's "Preferred" options eventually result in the use of an auction.[25] It is absolutely premature to conclude that any approach, especially a "preferred" approach, should include an auction without further consideration to what that auction would look like. There are simply too many variations on an "auction" for the Joint Commissions to abdicate to another agency a recommendation on what such an auction should look like for the electricity sector.

Furthermore, despite the use of auctions in other areas of the world, California's electricity sector is unique in its regulation. Unlike in the Regional Greenhouse Gas Initiative (RGGI), California's electricity market is comprised of both regulated entities (such as the POUs and IOUs) and unregulated entities (such as power marketers). The very nature of regulated markets carries inherent limitations. This regulation could impose restrictions on the ability of some utilities to participate in financial markets. As regulated entities, the State's retail providers are faced with certain limitations on investing and hedging. Whether those limitations are imposed by the CPUC or by local regulatory bodies such as City Councils, the effect is the same in that retail providers do not have the same flexibility to utilize hedging and other financial instruments in a cap-and-trade program.

This problem would be amplified in light of the fact that a potential auction structure has not even been addressed, and the regulated utilities could be forced to compete with marketers and investment groups that have no compliance obligations to meet and greater flexibility and access to capital in which to game the market. While all such practices are not necessarily illegal, they do put the entities directly responsible for providing reliable electricity to California's consumers at a competitive disadvantage.

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[24] D.08-03-018 Finding of Fact No. 30; Ordering Paragraph No. 9.

[25] Allocation Staff Paper, p. 23 (for preferred emissions-based approach), p. 32 (for preferred output based approach), p. 39 (preferred auction approach).

Even if an auction was limited or restricted only to entities with a compliance obligation, and assuming a separate auction for the electricity sector, with the participation of both regulated and unregulated entities in the same market, the playing field would not be level.

NCPA believes that at the very least, the Joint Commissions should not move forward with such a process until full consideration has been given to the economic impacts that an auction would have on the electricity sector's customers who would essentially bear the financial burden resulting from the administrative complexity, increased costs, and diversion of essential resources from the key objective of reducing emissions. Given the multiple objections raised by parties, the Joint Commissions should not make a recommendation to CARB regarding the electricity sectors' participation in a multi-sector auction absent careful and measured consideration of myriad details.

Before determining the role of an auction, CARB must ascertain the extent to which a cap-and-trade program will be utilized, and then determine the role that an auction will play in that program. As has been repeatedly demonstrated by parties to this proceeding,[26] and which was recently confirmed in the economic analysis conducted by Energy and Environmental Economics (E3), cap-and-trade is not necessarily the most cost-effective way to effect real emissions reductions, and may actually *increase* total costs to the electricity sector and electricity sector customers if cap-and-trade is implemented with heavy reliance on an undefined auction. NCPA believes that once the Joint Commissions complete their review of stakeholder input, as well as the E3 modeling, they will note that auctions without strict revenue recycling, have no place in the nascent stages of AB32 implementation in the electricity sector.

The Joint Commissions recommendation to CARB for the electricity sector should be focused on the means by which retail providers and entities with a compliance obligation can achieve real GHG reductions at the early stages of the program through mechanisms already in place, and further supplemented over the coming years with additional non-market-based developments, and market-based programs if necessary. As the CPUC's own economic

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[26] See: Comments on Allowance Allocation issues; Southern California Public Power Authority (SCPPA) October 31, 2007, p. 16; SCPPA, November 14, 2007 pp. 2-7; Los Angeles Department of Water and Power (LADWP), October 31, 2007, p. 7; Modesto Irrigation District (MID), October 31, 2007, p. 8.
See Also: Comments on February 8, 2008 Proposed Decision; California Municipal Utilities Association (CMUA), February 28, 2008, p. 2; LADWP, February 28, 2008, p. 2-10; MID, February 28, 2008, p. 9; Redding Electric Utility (REU), February 28, 2008, p. 3; SMUD, February 28, 2008, p. 5; Sempra Global, February 28, 2008, pp. 3-4; SCPPA, March 4, 2008, p. 5; Energy Producers and Users Coalition (EPUC), March 4, 2008, pp. 2-3.

consultant noted during the May 6 Workshop on modeling, unless the price of carbon reaches at least $90 per ton, it is not cost-effective to invest in any new renewable resources, and therefore, absent a $90 or greater carbon cost, cap-and-trade program does nothing but increase costs to electricity consumers.

Indeed, creating an auction market within a GHG reduction scheme could produce similar unintended consequences as those faced by regional transmission organizations (RTOs) where venture capitalists were able to thwart policy by purchasing congestion revenue rights for financial gain, to the detriment of consumers in those regions. Despite the best intentions of those working on this process, whatever protections are created to mitigate market manipulation, there are those that have little concern for the typical California consumer.

Even in the Northeast, the RGGI stakeholders have been working on development of an auction for more than six years. A final program is scheduled to begin this Fall, but has yet to be tested. That is clearly an indication that this issue is complex and does not lend itself to easy resolution.[27]

NCPA's proposal for distribution of allowances does not involve the utilization of an auction because it is simply too costly and risky for the State's consumers. Emissions allowances should be freely allocated and retail electric providers should utilize local and state measures to achieve real and permanent GHG reductions through energy efficiency and other measures that are not only dynamic, but specifically designed to effect the greatest reductions within their targets.

All Details Regarding the Structure and Governance of an Auction Must be Determined Before a Reasoned Recommendation to Utilize an Auction can Be Made.

The Allocation Staff Paper notes that "if ARB decides to implement a cap-and-trade system that includes auctioning of some portion of the allowances, the Commissions may wish to assist ARB in the future by analyzing and providing recommendations to ARB on electricity

[27] It is important to note that the 2007 auction design report commissioned for RGGI, while an informative resource, was prepared specifically for RGGI, which is comprised of a number of different states in an unregulated electricity market. Analysis, conclusions, and recommendations are directly and specifically tied to that market and do not necessarily have the same outcome when faced with California's regulated electricity market and anticipated deliverer point of regulation. A similar level of detail specific to the needs of a California-only market is clearly warranted before full consideration can be given to the value of an auction-based allocation approach.

sector-specific elements of auctions and ways to mitigate potential market manipulation." (Allocation Staff Paper, 32). However, this position puts the "cart before the horse." Because of the myriad details associated with an auction structure, it is impossible to simply say that an auction is recommended, without knowing more about what that auction will look like.

As noted above, use of an auction to advance a cap-and-trade program for the electricity sector is problematic at best, and at worst, extremely costly to the State's electricity consumers. Two of the most easily identifiable concerns are added costs (with little or no added value) and the high potential for market manipulation. CARB is looking to the expertise of the CPUC and CEC in making a recommendation that best meets the needs of the electricity sector; as such, the Joint Commissions have an obligation to California consumers to ensure that the recommendation is one that addresses all of these issues from the beginning. Each of the "Preferred" Alternatives anticipates a transition to auction, accordingly, "decision making in times of uncertainty", notwithstanding, there are many aspects of an auction that are not uncertain, and therefore, should be addressed up front.

Each of the issues raised below has significant direct impacts on the electricity sector, and must be addressed *before* the Joint Commissions can make a reasoned recommendation to CARB that the electricity sector should be included in a cap-and-trade program that involves an auction of allowances.

> <u>Who will administer the auction?</u> To date, there has been no meaningful discussion regarding the administrative costs associated with establishing and running an auction. The Allocation Staff Paper assumes only that the auction will be conducted by CARB or an auction agent overseen by CARB (Allocation Staff Paper, p. 33). An auction, by design, must involve an administrative structure – such a regime would likely be funded by auction revenues, which means those funds would not be available to effect actual emissions reductions. The fact that the auction would be run or overseen by a State agency does not diminish the cost implications. If an auction is adopted, electricity consumers would be forced to pay twice for compliance – first by bearing the costs associated with the restructuring of the retail electricity provider's portfolio and implementation of GHG reduction measures, such as energy efficiency and demand response, and second, by bearing the burden of funding the purchase of allowances at auction. There is no reason to believe that these costs will be insignificant or *de minimus.*

Any recommendation regarding an auction – from the onset or by transition – must take these costs into account.

Who may participate in the auction? Any auction in which the electricity sector is required to participate must limit market-participants to entities with a compliance obligation. Entities that do not have a compliance obligation should not be allowed to buy or sell emissions allowances. To permit otherwise opens the door to manipulation and gaming. While this may not be true on an economy-wide scale, within the electricity sector there are several well known examples of how the markets are susceptible to gaming, which puts the State's electricity consumers at risk. It is true that third parties may increase the liquidity of the markets, yet the opposite is also true that those same entities that have the resources to purchase allowances, with no corresponding obligation to reduce emissions, would be incentivized to game those allowances.

Proven examples of this potential for manipulation have played out not only in California, but in electricity markets throughout the country; most recently with regard to the auction of financial transmission rights. These financial rights are used to hedge congestion risks in markets with regional transmission organizations. However, purchase of these rights is not limited to load serving entities or generators that actually need to schedule electricity. This has resulted in large profits going to hedge funds that have been able to purchase the rights. Although the conduct of these entities is not illegal, it does add significant additional costs to the market price of the rights; costs which are ultimately borne by electricity consumers.[28] It is conceivable – and even likely that this would also occur in an auction for GHG emissions allowances.

California's electricity customers and our State's economy already bear the scars of past manipulation. The result is undue profits extracted that increase costs for consumers without furthering the key public policy objectives the market was designed to promote. Therefore, it is imperative that such manipulation not be allowed to occur again, and one means by which to reduce the potential for such manipulation is to ensure that only those with a compliance obligation are allowed to participate in any auction of allowances. It is absolutely imperative that lessons learned be used to ensure that any

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[28] Cal. Health & Safety Code §§ 38561(a), 38562(a), 38562(b)(1).

market-based implementation procedures provide a workable solution for electricity consumers.

The Allocation Staff Paper provides examples of several alternatives for CARB to pursue when it realizes that the California market is susceptible to manipulation, including limiting auction participants and participation by those with no compliance obligation.[29] However, rather than fully vetting these issues, the Allocation Staff Paper merely concludes that it does not have sufficient information to make a specific recommendation at this time. *Id*. NCPA believes strongly that such an analysis must be conducted *before* a recommendation is made to CARB. The fact that the Allocation Staff Paper acknowledges that sufficient information does not exist to make a specific recommendation is evidence enough that that the Joint Commissions ought not to recommend an auction, whether full or partial, without conducting an in-depth analysis of all the issues involved.

<u>How will the market be monitored and how will consumers be safeguarded against market manipulation?</u> The Allocation Staff Paper dismisses concerns regarding market manipulation by referring to the conclusions reached in a report commissioned specifically for RGGI. As noted above, that report was commissions specifically for RGGI – a region whose participants are all part of unregulated electricity market. They are several key distinctions between a California-only auction, and the one that is contemplated (and not yet initiated) in the Northeast.

Crucial to the design of any market is how that market will be monitored, and how both consumers and market participants can be protected. Some sort of market oversight must be established prior to implementation. On a regional level, NCPA, together with other electricity providers throughout the Northwest, have advocated for the development of an independent market oversight subcommittee (MOS) that would focus specific attention on the best approaches for designing and implementing safeguards against market manipulation, and identifying and recommending mechanisms for market abuse mitigation. At the commencement of auction development, any recommendation to CARB from the Joint Commissions must focus not only on crucial elements of market

[29] Allocation Staff Paper, p. 33

> oversight, but must also address and focus on mitigating the potential for abuse from the onset, as well as means by which the rules of the market can be enforced. The establishment of the MOS would be a key element in addressing this concern. [30] Even at the federal level, there is recognition that boundaries must be placed on the auctions by limiting those that can participate in order to protect against possible price manipulation.

NCPA believes that these crucial details must be methodically reviewed *before* the Joint Commissions can make a recommendation to CARB that allowance allocation within the electricity sector should include an auction. Furthermore, the Joint Commissions should also make a determination of whether or not the electricity sector should be subject to a separate auction, and not be part of an amorphous multi-sector auction, as could be interpreted from D.08-03-018. Under any configuration, an auction that includes the electricity sector must be gradually deployed.

2. *4/16; Q 10: 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.*

Auction revenues should be distributed to electricity customers via their retail electric providers. As noted in D.08-03-018, "it is important that any policy for distribution of allowances provide that revenues from the sale of allowances be used primarily to benefit customers in the energy sectors directly." (D.08-03-018, p.8) The value of allowances generated from trading within the electricity sector should be allocated directly to the retail electric providers with the compliance obligation to be used to offset the costs that entity incurs to reduce its GHG emissions, which in turn reduces the total cost to California's electricity customers. Retail providers with the compliance obligation are going to be called upon to reduce their GHG emissions using new and innovative technologies and resources that are likely to be more costly than those that have been employed in the past. At the same time, retail providers are going to be called upon to do so while continuing to reliably deliver an essential service to their customers. In order to do this in the most cost-effective manner, the value of any allowances

[30] NCPA also shares the concerns of Senator Feinstein regarding the potential for market manipulation. Senator Feinstein's *Emission Allowance Market Transparency Act of 2007* (S.2423, December 2007), raises the very real specter of manipulation of an emissions allowance market, and the adverse impact this would have on consumers.

should be directly controlled by those responsible for effecting the reductions.

The most efficient way to return auction revenues to California's electricity customers is to allocate allowance values back to the retail providers.[31] All proceeds derived from allowances in the electricity sector that are borne by the electricity sector consumers should be returned to those consumers. Allocating the value of allowances to the retail providers enables the entities that have the most direct relationship with the reductions goals the opportunity to custom-fit programs designed to achieve the greatest total benefit for any given community, while achieving the goals of AB32. For example, retail providers would be able to implement greater and more aggressive energy efficiency programs, which have multi-faceted benefits in that by directly reducing a customer's consumption of electricity, the customer has a lower electricity bill, and the state's overall demand for GHG intensive resources is reduced. Additionally, expanded renewable energy programs allow similar benefits. It is the retail provider who is responsible for portfolio management that is in the best position to effect such reductions, and who should therefore be able to utilize the revenues associated with electricity customer allowances to invest in those reduction measures. Furthermore, low income and other special-needs customers will likely be severely impacted by the economic impacts of AB32 implementation, and those customers must be protected; this function is best performed by the retail provider.

B. Response to staff paper on allowance allocation options and other allocation recommendations. Q8-Q13 (4/16/08) and Q6 (5/13/08).

In the following section, these comments address each of the three "preferred" approaches addressed in the Allocations Staff Paper: (1) Preferred Emissions-Based Approach (p. 23), (2) Preferred Output-Based Approach (p. 31), and (3) Preferred Auction Approach (p. 39). Following that discussion, the comments address the questions included in the "Suggested Outline" set forth in the May 13 Ruling.

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[31] Question 10 asks parties to describe their preferred method for returning auction revenues to benefit electricity consumers in California. NCPA notes, however, that the free distribution of allowances would relieve entities with the compliance obligation from the need to expend unknown sums on the purchase of emissions allowances; instead allowing those entities to utilize all of their existing resources on investments in energy efficiency, renewable energy, and other programs that would reduce overall GHG emissions and avoid the need for future allowances.

1. Preferred Emissions-Based Approach:

This approach would begin with allocating at least 50% of the total allowances based on historical emissions, with the remaining allowances distributed based on either output or auction. Such an approach disadvantages those that have historically lower GHG emitting portfolios who will still be called upon to participate in mandatory reductions. While it is intuitive that entities with higher emissions profiles will need to achieve greater emissions reductions, it is not clear what the emissions reductions goals will be for the entire sector, and entities that have historically lower emissions profiles may still be called upon to make significant reductions. Until entities with lower-GHG emitting portfolios can be assured that their reduction obligations will be linked with their current emissions profiles, it is premature to look only to allocation methodologies that are essentially based on the assumption that only entities with higher GHG emissions will be required to make significant reductions.

Under the Preferred Emissions-Based Approach, entities with lower historic emissions will be placed at an economic disadvantage by being allocated fewer emissions allowances. This is especially problematic with regard to entities that have maximized their ability to utilize low-emitting resources, and will have to turn to natural-gas or other fossil-fuel based resources to meet load growth and ensure the continued reliable delivery of electricity to retail consumers. Such is further compounded in areas experiencing rapid load growth, where retail providers investing in lower GHG emitting resources are penalized by not receiving emission allowances for these resources, yet still being called upon to serve the fast-growing load.

For NCPA members, such an allocation methodology is even more egregious if the remaining allowances are placed into an auction. The allocation of allowances in such a manner severely impacts entities with lower GHG emitting portfolios; since many of these entities are also smaller retail providers, the economic impacts are further exacerbated and the adverse impacts on the electricity customers of those providers is even greater. As the Allocations Staff Paper notes, this methodology also fails to recognize entities that undertook GHG-reducing actions prior to the establishment of the baseline,[32] but does recognize those that have

[32] Allocations Staff Paper, p.15.

investments in resources that are high GHG emitting resources.[33]

If an emissions-based methodology is adopted, it is imperative that the adverse impacts be mitigated by transitioning to a different benchmark on a much steeper slope than that proposed in the Allocations Staff Paper (Id., p. 24), and there should be no transition to auction, especially in the beginning.

Transition to auction must be avoided. Instead, a transition to an output-based allocation helps to minimize the adverse cost implications associated with the approach. At the same time, it is important to note an output methodology that does not include allowances for non-fossil fuel resources is still inherently discriminatory, since even retail providers (and generators) with clean generation resources will be called upon to reduce their emissions.

2. Preferred Output-Based Approach

The Preferred Output-Based Approach would begin with the majority of the allowances being allocated to entities based on their total output, with the remaining allowances distributed through an auction. This approach includes a seven-year glide path to full auction. However, as a practical matter, the Preferred Output-Based Approach suffers from many of the same deficiencies as the Preferred-Emissions Based Approach, in that it is based on the assumption that entities with a currently clean or "green" portfolio will be able to maintain that existing portfolio with little or no need to purchase fossil resources. This problem is further exacerbated by the fact that it is still unknown what level of reductions those entities will be required to make, and by denying allowances to non-fossil resources, those entities will be further disadvantaged in their pursuit of emissions reductions.

In its purest form, this approach is the same as an emissions-based approach. It allocates allowances to entities based on the emissions level of their resources, and not based on the actual electricity produced. It continues to recognize the challenges faced by generators with high GHG emitting resources, and continues to ignore the less intuitive – but just as costly – implications on generators and retail providers with lower GHG emitting resources.

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[33] It is important to note that there is a clear distinction between *recognizing* early actions, and *rewarding* early actions. Entities that have made considerable investments in low-emitting resources should have the costs associated with those resources *recognized* in any allowance allocation program. Health & Safety code § 38562(b)(3).

3. Preferred Auction Approach

If an auction is to be employed, NCPA fully supports the allocation of auction revenue rights (ARRs) to retail providers. The Preferred Auction Approach recommends that distribution of ARRs begin with 100% based on historic emissions, with a gradual transition to eventually result in 50% historic emissions and 50% sales-based distribution by 2020.

Clearly, if there is to be an auction, it must be designed to include provisions by which all of the auction revenues remain in the electricity sector.[34] In the Preferred Auction Approach, 75% of the emissions allowances would be allocated through an auction from the onset. The first and primary problem with the approach is that it is designed around the generic assumption of an "auction," without any details regarding how that auction would be administered or look. As noted above in Section III.A**,** this is a faulty premise upon which to establish a "preferred approach" and leaves very important questions and concerns unanswered and unaddressed. The remaining emissions would be allocated based either on output or emissions (both of which essentially recognize only high GHG emitting resources).

With 100% of the revenues recycled back to the electricity sector, the overall impact is not necessarily as egregious as an allocation based purely on historic emissions. However, NCPA believes that these numbers – even if favorable at first glance- are misleading. It is theoretically impossible to state that an auction will be implemented and that 100% of the revenues will be available for distribution. Regardless of how simple an auction is structured, there are going to be administrative costs involved. Accordingly, each dollar that is spent on administering the market-based program is not available for ultimate distribution to the electricity sector. Accordingly, $1 paid into the auction will not equal $1 back to the electricity sector.

Furthermore, without any details regarding the structure of the auction, there is nothing to protect against the possibility that entities will purchase allowances from the auction in excess of what they need (or perhaps, do not need at all), and then sell those allowances *outside* of the auction. The scarcity of the resource and the timing of the auction may enable such entities to

[34] Allocations Staff Paper, pp. 35-36.

sell their emissions allowances at a profit outside of the auction. If the allowances are sold outside of the auction, then the revenues are not part of the pot of money being distributed back to the electricity sector, and likely the cost of those allowances is greater.

If a recommendation is made that the use of auctions should be further developed by CARB in the Scoping Plan, the Joint Commissions should also recommend that the glide path for ARR distribution be short and steep in favor of sales-based distribution. Since retail providers will be best situated to effect the greatest emissions reductions and cost-containment mechanisms, it is imperative that those entities also be allocated the ARRs necessary to carry out those reductions.

> 4/16; Q8. The staff paper describes an option that would **allocate emission allowances directly to retail providers**. If you believe that such an approach warrants consideration, please describe in detail how such an approach would work, and its potential advantages or disadvantages relative to other options described in the staff paper. Address any legal issues related to such an approach, as described in Questions 2 – 4 above.

In order to maximize the economic efficiencies and reduce the cost burdens of AB32 implementation on California's electricity customers, allowances should be allocated directly to retail providers. It cannot be stressed enough that retail providers are best situated to ensure real GHG reductions through a portfolio of programs.

> 4/16; Q 10. 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.

4/16; Q10 answered above.

> 4/16; Q 11. 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?

An auction should not be implemented until all of the concerns and questions regarding administration of an auction have been fully addressed, and even then, not until the markets have matured enough to be able to handle the possible price fluctuations that would be so detrimental to the State's consumers. If there is an auction, revenues should be distributed to the retail providers to use for the benefit of their electric customers. Each retail provider should be able to utilize the revenues for the maximum benefit of the communities that they serve. For some communities, that might be through increased investments in energy efficiency, while for others it may be for expanded renewable energy programs. The Joint Commissions should avoid making a single “one-size-fits-all” recommendation on how much money should be expended on any one program for any one retail provider. Rather, the retail providers should be given the greatest flexibility possible to ensure that economic efficiencies are maximized in the communities in which they serve.

> 4/16; Q 12. 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.

The Joint Commissions should not recommend adoption of an auction until all of the details regarding administration of an auction have been addressed and resolved. If an auction is adopted, as noted above in Section III.B.3, there are several important goals to be accomplished with auction revenues. First of all, the revenues should be directed to retail providers. It is important that rates remain affordable, both for the well-being of California’s consumers and the economy. However, there are also several other important goals to be achieved, including furthering the development of renewable energy resources and development of new and expanded energy efficiency programs.

> 4/16; Q 13. If you prefer a combination of methods for returning auction revenues, describe your preferred combination in detail.

No auction should be adopted until all of the concerns regarding administration of the auction have been addressed, including the potential for additional costs that will be funneled into administering an auction and taken directly from emissions reduction measures. If an auction is eventually adopted, the best means by which to distribute auction revenues is to allocate them to retail providers based on annual retails sales.

IV. FLEXIBLE COMPLIANCE

A. Detailed proposal Q1 (5/6/08)

> 5/6; Q1: 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.

The ability to utilize those programs and tools referred to as flexible compliance mechanisms will be key to the overall success of AB32 implementation. The greater the flexibility to seek out the most cost-effective means by which to achieve actual emissions reductions, the greater the total reductions that can be achieved. With that said, as this early stage in AB32 implementation, when CARB has not yet determined if a cap-and-trade will even be adopted, or whether there will be other market-based mechanisms employed, it is too premature to put forth a detailed proposal of what flexible compliance mechanisms should look like. The development of such programs must begin with comprehensive definitions of the kinds of tools available, and include safeguards to ensure that the integrity of the entire program is not compromised. With these key elements in mind, the Joint Commissions should recommend to CARB that flexible compliance mechanisms will be an important part of effecting meaningful emissions reductions and meeting the emissions reductions goals set for 2020 and into the future, and that these various options should be more fully explored and developed.[35]

B. Scope of market and related issues

Flexible compliance mechanisms are an important tools for meeting the mandates of AB32. Each of the various alternatives discussed in the May 6 Ruling provide opportunities that should be included in the Scoping Plan as alternatives that should be fully explored and further developed in the coming months.

E. Compliance periods Q12-Q13 (5/6/08)

[35] California's efforts to develop comprehensive and environmentally sound flexible compliance alternatives is greatly assisted by its participation in the Western Climate Initiative (WCI), which has devoted significant time and resources to addressing many of the complex issues raised in the May 6 Ruling, and has held several conference calls and one day-long meeting to address just this issue. Although the information being developed by WCI is in the context of a regional trading program, in order to avoid duplication of efforts and to maximize on the diversity of expertise in this area, the information gathered in that effort should be incorporated into CARB's record and further analyzed in light of a California-only program.

5/6; Q12: 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?

The Joint Commissions should recommend to CARB that the compliance period for the electricity sector be a multi-year period, such as that recommended by the WCI in its initial Program Design Recommendation[36] This will allow entities with the compliance obligation to accommodate years in which resources do not produce as expected. This is vitally important in California, where a large number of retail customers are served by renewable resources, such as hydroelectric power. This will also be increasingly important as the dependence on renewable resources expands across the state.

F. Banking and Borrowing Q14-Q16 (5/6/08)

The Joint Commissions should recommend that CARB allow banking and borrowing as compliance options for the electricity sector. Banking and borrowing are going to be important options for meeting reduction obligations, especially in California's electricity market. The result could be years in which emissions reductions far exceed expectations, and other years where reduction goals are not quite met. The ability to bank or borrow allowances from one year to the next will be invaluable in dealing with situations such as these. The details, however, regarding exactly how such a program should be developed would need to be fined tuned and worked out in conjunction with resolution of an overall market structure. Until that time, NCPA strongly encourages the Joint Commissions to recommend to CARB that the ability to bank and borrow be included in the initial Scoping Plan, that details be further developed in the coming months.

G. Penalties and alternative compliance payments Q17-Q20 (5/6/08)

If CARB determines that penalties should be imposed on entities that fail to meet their compliance options, such a determination should not be made until such time as the final market design has been established and compliance obligations have been set. Any

[36] Western Climate Initiative Draft Design Recommendations on Elements of the Cap-and-Trade Program (May 16, 2008), p. 16.

penalties imposed must be commensurate with the level of non-compliance, and must not be initiated until after all of the initial challenges regarding AB32 implementation have been worked out. As a practical matter, allowing entities to "buy their way out" of a compliance obligation would not meet the mandates of AB32 or the goals of the state. Any penalties or fees should be designed so that compliance is the primary goal, and that payment for non-compliance is not deemed as a business option.

The Joint Commissions should recommend to CARB that imposition of penalties and non-compliance payments should be more fully explored after the fundamental program design elements, including compliance periods and total reduction obligations, have been established.

H. Offsets Q21-Q26 (5/6/08)

As with banking and borrowing, offsets have the potential to be an important and invaluable tool to facilitate compliance. The Joint Commissions should recommend to CARB that the Scoping Plan include the option to utilize offsets, and that details regarding the kinds of offsets, geographic limitations, and technologies be further developed.

V. TREATMENT OF CHP

A. Detailed proposal Q1 (5/1/08)

> 5/1; Q1: 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.

Defining the appropriate regulatory treatment of GHG emissions from CHP facilities under AB32 is a complex undertaking, and presents a unique blend of technical and policy issues. NCPA does not present here a detailed and comprehensive proposal, but rather offers several principles for consideration in the AB32 implementation process. First, regulation of GHG emissions from CHP facilities should not disadvantage CHP technologies or applications. Second, regulations should recognize the unique efficiencies that CHP facilities provide. Third, the burden of regulation should be fairly allocated between the electricity generation and thermal energy production components of CHP.

B. Regulation of CHP GHG emissions Q2-Q15, Q17, Q24 (5/1/08)

5/1; Q2: Should GHG emissions from CHP systems be regulated in one sector? If so, which one? How?

CHP systems do not fit neatly into a single existing sector, but regulation in the electricity sector would be appropriate for the majority of CHP systems, and result in administrative efficiency. Regulation in a different sector (e.g., industrial) may be appropriate for some CHP systems, such as bottoming-cycle units that do not provide electricity to the grid. Creating a flexible regulatory system may also result in administrative efficiency.

5/1; Q3: 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 most in-state CHP systems, all of the GHG emissions should be regulated as part of the electricity sector. For electricity that is not delivered to the California grid, the owner of the facility (i.e., the entity that is in the best position to take action to reduce GHG emissions) should be the point of regulation.

5/1; Q5: Should CHP units be placed in different sectors based on CHP unit capacity size?

There is no basis for placing CHP units in different sectors based on CHP unit capacity size, any more than placing conventional power plants in different sectors based on capacity size. As stated above however, consideration should be given to placing smaller, CHP systems that use the electricity output on-site in a different sector.

5/1; Q7: Should the type of GHG regulation (i.e., cap and trade or direct regulation) be different for a topping-cycle CHP unit versus a bottoming-cycle unit?

Subject to the response to Q2 above, whether a CHP unit is a topping-cycle or a bottoming-cycle unit should have no bearing on the type of regulation.

> 5/1; Q8: Should the sectors used for GHG regulation be different for topping cycle and bottoming cycle CHP units?

Whether a CHP unit is a topping-cycle or a bottoming-cycle unit should not be the sole determinant on which sector is used for GHG regulation. Consideration should also be given to whether or not the electricity output is delivered to the grid or used on-site.

> 5/1; Q9: Should CHP be part of a cap-and-trade program or not? If so, should the entire unit or certain CHP outputs be part of the cap and trade program?

Whether CHP should be part of a cap-and-trade program may well depend on the point of regulation that is ultimately determined. As a general rule however, if a cap-and-trade program is implemented, and if the electricity sector is included in that program, there is no legal or technical basis for excluding CHP from the program. All outputs from the unit should be part of the program.

> 5/1; Q10: 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?

If a deliverer point of regulation is adopted by CARB for the electricity sector, then electricity delivered to the California grid by a CHP unit should also be regulated under the deliverer point of regulation. There is no basis for treating CHP units differently than conventional sources of electricity for this purpose.

> 5/1; Q11: 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?

With the possible exception of bottoming-cycle CHP units, unless California chooses to specifically encourage the application of CHP generation, electricity generated by in-state CHP systems for on-site use also results in GHG emissions, and should generally be subject to similar regulatory treatment as CHP electricity delivered to the California grid. Conventional generation sources used as distributed generation for on-site use are subject to the same regulatory treatment as distributed generation delivered to the California grid.

> 5/1; Q12: If CHP is regulated in the electricity sector (either as one combined unit or based only on the total electricity output or based only on the electricity delivered to the California grid), do any of the proposed staff allocation options for electricity need to be modified? How?

If CARB decides to regulate CHP as part of the electricity sector, this determination provides no basis for modifying the proposed staff allocation options with respect to CHP.

> 5/1; Q13: If CHP is treated separately from the electricity sector, but is still included as part of a cap-and-trade program, how should allowance allocation to CHP units be handled**?**

If CHP is not regulated as part of the electricity sector, but is still included as part of a cap-and-trade program, the allowance allocation to CHP units should include the electricity and thermal output from the entire unit.

> 5/1; Q14: If allowances are allocated administratively to CHP units, should the allocations take into account increased efficiency of CHP? If so, how?

The allocations should take into account the increased efficiency of CHP, and should do so by including allocations for 100% of both electricity and thermal output. New CHP units should be allocated allowances based on the upgraded combined efficiency. Allocation options should encourage, and not penalize the use of CHP.

> 5/1; Q15: Are there advantages to having all emissions from in-state CHP regulated as part of the electricity sector under cap and trade (and therefore with the need for only a single set of allowances?) How should this be accomplished?

The primary advantage to having all emissions from in-state CHP regulated as part of the electricity sector under cap and trade is that emission reductions from the entire unit would be attributable to the deliverer, the entity in the best position to reduce GHG emissions.

> 5/1; Q17: What is the best approach to regulation of CHP emissions to minimize the potential for disincentivizing new installations of CHP and why is that the best approach?

Treating all of the output of new installations of CHP in the same manner should minimize disincentives that would be created by treating the electricity output differently than the thermal output. New CHP installations should also be available to claim emissions reductions for the combined increase in efficiency, even if the prior heat and power resources were owned by separate entities. This would also create greater administrative efficiencies.

> 5/1; Q24: Would including all of CHP in cap and trade create a disincentive if natural gas is not regulated under cap and trade?

Treating all of CHP in cap-and-trade if natural gas is not regulated under cap-and-trade may create a disincentive for CHP if the cost of regulation is greater than the energy efficiency savings that CHP could provide.

C. CHP as an emission reduction measure Q16, Q18-Q21, Q23 (5/1/08)

> 5/1; Q16: Should CHP be considered an emission reduction measure under AB 32? Why or why not?

CHP should be considered an emission reduction measure under AB32. As a rule, fewer emissions are produced as compared to the emissions produced by the non-CHP production of the same electric and thermal output.

> 5/1; Q18: Should ARB and/or the Commissions consider policies or programs to encourage installation of CHP for GHG reduction purposes? Why or why not?

In addition to the inherent energy efficiencies of CHP, AB 1613 (2007) provides further incentives by ensuring a market for excess electricity generated.

> 5/1; Q19: Should CHP have an efficiency threshold in order to qualify as an emission reduction measure? If so, why?

A specific efficiency threshold for CHP to qualify as an emissions reduction measure is unnecessary. Quantifying such a threshold would prove troublesome and may penalize existing CHP units.

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

A. Electricity emission reduction measures Q1-Q2, Q5 (5/13/08)

5/13; Q1: 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?

NCPA expects the CARB Scoping Plan to emphasize that the majority of the emissions reductions – especially in the coming years, will come from existing and further developed regulatory programs. With that said, it is important for the load serving entities and generators that will be responsible for emissions reductions to have flexibility in how they achieve those goals. In addition to complying with existing regulatory mandates, retail providers will be called upon to effect even greater GHG reductions due to AB32. In order to meet these mandates, a full panoply of tools should be available to the retail providers to implement the most cost-effective programs that work within their service territory. By necessity, these programs will not be limited to the existing energy efficiency and renewable energy programs in place, but will expand to include new and innovative solutions to meeting emissions reductions targets – many of which are yet to be discovered. The most important matter to consider in this context, is that retail providers should not be limited or restricted in utilizing options that work best for them, nor should they be required to squander valuable resources on emissions reduction measures that simply will not work within their communities.

For example, as NCPA has noted in the past, energy efficiency programs that are exceedingly successful in one geographic area can be dismal failures in other areas. Air-conditioning cycling programs will result in little to no actual energy reductions in cities such as Alameda and Lompoc, but would be key tools in areas served by the Turlock Irrigation District and the Redding Electric Utility. At the same time, areas served by entities such as the Truckee Donner Public Utility District must look to unique and innovative programs that meet their "reverse" peaking load that results from the large number of "temporary residents" that frequent the area in the off-peak winter months. These kinds of impacts are felt to an even greater degree within smaller and geographically limited service areas.

Likewise, with regard to the development of renewable energy resources, transmission infrastructure, the availability of lower-GHG emitting firming resources, and the peak demand times, are all going to factor into what renewable resources should be used by which communities. Regardless of the best intended mandates, these factors will not change.

> 5/13; Q2: Are there additional regulations that ARB should promulgate in the context of implementing AB32, that would assist or augment existing programs and policies for emission reduction measures in the electricity and natural gas sectors?

As noted above, the adoption of AB32, and its subsequent implementation, will by necessity give rise to a great number of innovative programs for emissions reductions, as those with compliance obligations seek to achieve mandated goals, and yet – especially as it pertains to retail electric providers – meet their obligations to continue providing the State's electricity customers with reliable and competitively-priced electricity. It is safe to say that many of these programs have likely not even yet been developed. Yet the requirement to meet the legislatively mandated reductions alone will give rise to the innovation necessary to accomplish this goal. NCPA does not believe that the adoption of additional resources will in any way hasten or facilitate this effort. Entities with the compliance obligation must be allowed the flexibility to lawfully meet their emissions reduction targets by means that best fit the needs and demands of their individual communities.

> 5/13; Q5: 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?

The majority – if not all – of the emissions reductions for the electricity sector could likely be accomplished through programmatic and regulatory measures, without the need for the implementation of potentially costly market-based measures. Programmatic and regulatory programs are part of the core measures that CARB currently anticipates will account for at least 60% of the total emission reductions across that state, and anticipated more within the electricity sector. The Joint Commissions should recommend to CARB that no *minimum* number of reductions be assigned to market-based programs for the electricity sector. Rather, retail providers should be charged with maximizing the total possible reductions that can be achieved through programmatic and regulatory measures for before 2020, and not until the efficacy of these measures has been determined should the viability of achieving additional reductions through market-based programs be contemplated.

C. Annual emission caps for the electricity and natural gas sectors Q4 (5/13/08)

> 5/16; Q4: The scope of this proceeding includes making recommendations to ARB regarding annual GHG emissions caps for the electricity and natural gas sectors. What should those recommendations be? What factors (e.g., potential effectiveness of identified emission reduction measures, rate impacts for electricity and natural gas customers, abatement cost in other sectors, anticipated carbon prices) should the Commissions consider in making GHG emissions cap recommendations? If sufficient information is not currently available to recommend cap levels, what cap-related recommendations should the Commissions make to ARB for inclusion in its scoping plan?

The Joint Commissions must make a recommendation to CARB regarding the total amount of emissions reductions for the electricity sector. Entities in the electricity sector must know their total compliance obligation in order to determine the most efficient and cost-effective means by which to achieve that stated goal. The Joint Commissions should include the recommendation to CARB on the total amount of emissions reductions that will be required from the electricity sector. Until entities know the total emissions requirement for the sector, as well as the total emissions reduction for each entity within the sector, the cost impacts and information set forth in the modeling is purely speculative.

During the May 19 CARB Workshop, CARB staff noted that one of their objectives was to "assure that emissions reductions required of each sector are *equitable*."[37] However, staff specifically noted that "equitable" does not mean "equal." CARB has acknowledged that overall, AB32 emission reduction levels could be achieved if each sector reduced its emissions by approximately 30%. Yet, CARB has also acknowledged that 30% reductions will not be

[37] May 19 CARB Workshop, Workshop presentation, Slide 5, Plan Objectives; Slide 19, Criteria for Crafting a Preferred Approach (emphasis added).

required of each sector. Accordingly, there are some sectors, such as the electricity sector, that will be called upon to achieve emissions reductions in excess of 30% (or their fair share) - - despite the fact that the electricity sector is currently already below the benchmark 1990 emissions level referenced in AB32. As noted in a paper prepared for an informational hearing before the Senate Energy, Utilities and Communications Committee, the electricity sector's 1990 GHG emissions levels are actually higher than the current GHG emissions levels, despite a 28% increase in electricity use.[38]

CARB has acknowledged that certain criteria should be used to determine a preferred approach for achieving the objectives of AB32;[39] in addition to assuring that the emissions reductions required of each sector are equitable, other primary criteria include the ability to reach the target for 2020, maximization of economic benefits, minimization of economic harm, and providing leadership and influence to other governments.[40] Discussed in the context of determining an overall preferred approach for statewide emissions reductions and AB32 implementation, these criteria are also applicable in determining the reduction levels that should be required of each sector. However, while the total costs of GHG reductions will greatly and directly impact California's consumers, CARB has noted that the cost-effectiveness of its preferred approach – and total reduction levels for each sector – will need to be balanced against such factors as "broader societal benefits, complimentary policy goals, and sector equity."[41] The majority of the modeling to date has been done in the electricity sector; combined with the fact that there are easily identifiable and tangible means by which to assign reduction targets to almost all aspects of the electricity sector, there is a very high probability that a discussion of these non-precise criteria could lead to the conclusion that it is "equitable" to require a far greater percentage of the State's overall GHG emissions reductions from the electricity sector. NCPA believes that it is incumbent upon the Joint Commissions to do an analysis of these criteria and make a recommendation to CARB regarding the total feasible and cost-effective reductions that

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[38] Senate Energy, Utilities and Communications Committee, Information Hearing, AB32 Implementation: Understanding a Cap and Trade System, May 21, 2008, *Carbon Trading Backgrounder Paper*. The Paper notes that 1990 electricity sector emissions levels were at 111 MMT, while 2008 levels are 108 MMT.

[39] Cal. Health & Safety Code § 38562(b)(1).

[40] May 19 CARB Workshop, Workshop presentation, Slide 19, Criteria for Crafting a Preferred Approach.

[41] May 19 CARB Workshop, Workshop presentation, Slide 24, Cost Effectiveness.

can be *fairly* achieved by the electricity sector. The Joint Commissions should provide CARB with a recommendation on the *total emissions reduction requirement* for the electricity sector.

VII. MODELING ISSUES

A. Methodology Q8 (5/13/08)

5/13; Q8: 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?

Clearly, the E3 tool is useful for purposes of obtaining a snapshot of the impacts on various segments of the electricity sector in 2008 and 2020. However, it is imperative that the Joint Commissions understand that the level of aggregation involved in the model scenarios do not provide for any meaningful review of the impacts on utilities included in the "Northern POU Other" category, or the customers of those utilities. For example, this group includes not only publicly owned utilities of widely divergent sizes and resource portfolios, but also a multi-jurisdictional IOU. Accordingly, the E3 model results cannot be used to accurately depict the impacts on that aggregated group, as the results reflected in the May 6 workshop presentations are not representative of the actual impacts to the individual members.

In addition to concerns surrounding the lack of needed utility disaggregation, the model does provide the ability to address annual impacts during the all-important transition period between 2012 (date of program implementation) and 2020 (the date of the target reduction). In order to understand the proper perspective in which the Joint Commissions can utilize this model, these comments expand on a number of limitations surrounding the *GHG Calculator*:

1. The GHG Calculator is unable to provide the level of detail needed to effectively evaluate individual NCPA member impacts.

As designed, the E3 GHG calculator divides the electricity sector into seven distinct sectors: PG&E, SCE, SDG&E, SMUD, LADWP, Northern California–Other, and Southern California–Other. Moving the analysis beyond the state's largest utilities requires further disaggregation of the data provided in the E3 GHG calculator. Smaller utilities are clearly not represented appropriately. Take NCPA's situation as an example. NCPA's 15 utility members are included in the "Northern California – Other" category, as well as some portion of PG&E's and DWR load, as well as all of Modesto Irrigation District. From an analytical perspective, NCPA and the other entities included in this category have a wide range of carbon footprints, not making any group of utilities within the category representative of the aggregated group included in the Northern California – Other category. To that end, NCPA represents approximately 60 percent of the category, suggesting that conclusions reached using the E3 model cannot appropriately reflect the needs of NCPA and any other entity included in the category.

To E3's credit, E3 has acknowledged the shortcomings of the model in this regard, recognizing the budgetary implications of providing the level of disaggregation needed to meet the needs of NCPA and other publicly-owned utilities. NCPA has held numerous discussions with E3 staff to address this issue and agreed early in this proceeding that it would develop a complementary model to disaggregate the data in a manner that would best reflect the analytical needs of NCPA while concurrently validating the results being generated by the E3 model.

The NCPA Model Developed by R.W. Beck Addresses the Lack of Disaggregation in the E3 Model for NCPA and its Members. The NCPA Model, an Excel-based spreadsheet, was developed by R.W. Beck in 2007 to evaluate the relative impacts of GHG policy within the electricity sector and allow NCPA an opportunity to assess these impacts at the individual member level. The model itself contains ten retail provider categories, as opposed to seven offered by the E3 model, with the key differences being the breakdown of NCPA, the Southern California Public Power Authority (SCPPA), Modesto Irrigation District (MID), and the Department of Water Resources as distinct data sets. In addition, each of the 15 NCPA member utilities were modeled, and the model has the flexibility to add additional utility detail if desired. As is the case with the E3 model, much of the data inputs are based on publicly-available data.

While the resource assumptions included in the model are simplistic by comparison to the E3 model, the value of the model stems from its ability to evaluate various allowance allocation scenarios on an annual basis, beginning in 2008 and ending in 2035. Other features of the model include the following:

- User defines each resource scenario
- Model calculates annual emissions for each based on existing resource portfolio plus imports

- Calculates allowances needed
- Allocates allowances to each LSE under 13 different approaches, including those identified by the pending Lieberman-Warner bill
- Shows, based on that allocation, which utilities need more allowances versus those that have allowances to sell
- Computes total cost of change in generation portfolio and cost of buying/selling allowances.

In general, the model follows the State's loading order, filling retail provider load requirements first with energy efficiency and renewable energy, followed by generation driven by natural gas. In addition, existing coal contracts are not renewed upon expiration, and all retail providers are assumed to meet or exceed 20% by 2010.

To validate the use of both models and ensure that the results from common retail provider groups is within an acceptable bandwidth, NCPA ran its Preferred Case in both models and compared results. The results of this comparison are provided in following two tables. Looking at key data points within the models, the difference between the California revenue requirements in the two models is approximately 6%, with the change in rates between the two models less than 2%.

Figure 1

Comparison of E3 GHG Calculator and NCPA Model
NCPA Preferred Case - 2020

	E3 GHG (MM$)	NCPA Model (MM$)	Difference
CA Revenue Requirement (MM$)	46,319	43,452	(2,867)
Cost Difference 2020 vs 2008 (MM$)	9,857	11,174	1,317
Rate Change 2020 vs 2008 (%)	15.6%	17.3%	1.7%

Sources: E3 GHG Calculator, NCPA Preferred Case 1
NCPA Model Prepared by R.W. Beck.

The next step to validate the models was to compare the net carbon costs of key retail provider groups. In this case, it is clear that the trends associated with PG&E, LADWP, and

SMUD are consistently in the same direction and relatively close in terms of percentage differences. There are other tests that NCPA ran to validate the model's use vis-à-vis the E3 model. Combined with the various discussions held with E3, as well as similar discussions with staffs of the Joint Commissions, NCPA is confident that the level of disaggregation supported by the NCPA Model makes the NCPA Model usable for analytical purposes in this proceeding.

Figure 2

Comparison of E3 GHG Calculator and NCPA Model
Net Carbon Costs
NCPA Preferred Case - 2020

	E3 GHG (MM$)	NCPA Model (MM$)	Difference
PG&E	(250.3)	(234.5)	15.8
LADWP	87.3	117.3	30.0
SMUD	(22.1)	(22.0)	0.1

The following section utilizes the E3 model and the NCPA Model to highlight how the results calculated by the E3 model might be somewhat misleading to specific groups of utilities within a category. Figure 2 shows the differences between the Northern California – Other category, as run by the E3 model, and NCPA's member utilities, as calculated by the NCPA model. The results from the two calculations clearly yield differing trend lines. While the net cost of carbon increases $21.3 million for 2020, NCPA members actually realize a decrease of $8.1 million, a result that runs completely counter to the result calculated by the E3 model. Policy determinations made without regard for these types of divergences might create unintended consequences for nearly 400,000 consumers in California, those served by NCPA's member utilities.

Figure 3

Comparison of E3 GHG Calculator and NCPA Model
Net Carbon Costs
NCPA Preferred Case - 2020

	E3 GHG NoCal Other	NCPA Model NCPA	Difference
Revenue Requirement (MM$)	2,479.0	1,479.0	(1,000.0)
Net Carbon Cost	21.03	-8.1	(29.1)

Sources: E3 GHG Calculator, NCPA Preferred Case 1
NCPA Model Prepared by R.W. Beck.

The situation gets even more precarious when looking at the needs of individual utilities. From the perspective of any local municipal utility that is not LADWP or SMUD, the E3 model offers only gross assumptions as it relates to each of the individual investor owned utilities while imparting those results to the smaller publicly owned utilities aggregated in groups such as Northern California–Other or Southern California–Other. Without question, individual members have unique carbon footprints, resource investment patterns, energy efficiency programs, and climate zones that may affect the interpretation of any model results, and must be considered while developing policy recommendations in this proceeding.

2. The results presented by E3 are not indicative of overall impacts, as they are only "snapshots" of 2008 and 2020.

In comments submitted earlier this year to the CPUC[42], NCPA argued that "the model is limited by its inability to measure AB32 impacts between 2008 and 2020, and beyond 2020." E3 responded that the "since information on 2020 is the primary factor required for the GHG docket by the Joint Commissions for the decisions must make this year, we intend to keep 2020 as the farthest date possible."[43] This approach remains a concern for NCPA and its members, and E3 recognizes that its model will not be able to accommodate the ability to address changes on an

[42] See NCPA Comments on Modeling-Related Issues (January 4??, 2008), p. 5.

[43] E3, "Proposed Stage 2 E3 GHG Calculator Modeling Approach," filed April 1, 2008.

annual basis.

With few exceptions, E3's approach provides a linear interpolation of data manipulation between 2008 and 2020, with no ability to test the sensitivities of more aggressive implementation direct reduction and market-based strategies under differing timeframes and varying benchmarks. This approach does not comport with typical resource planning activities nor does it consider corresponding changes in utility cost and rate structures. In NCPA's case, the full value of aggressive renewable resource development such as the Western Geothermal project, a 35 megawatt project scheduled to be available to NCPA members in 2010, would not provide the appropriate level of credit in calculating GHG mitigation obligations. Waiting ten years for such acknowledgement from a modeling perspective severely understates the value of such investments. NCPA is not alone in its views with regard.

Looking at the issue from another perspective, the Figure that follows directly below, the results of various outputs can vary from year to year and are certainly not linear in nature. As an example, Figure 4 presents the amount of additional auction revenues available to NCPA members above and beyond the dollars spent by NCPA in a potential auction in the CPUC Preferred Output-Based Approach, assuming that 100% of the auction revenues are returned to load serving entities. As shown, net revenues vary from $0.2-5.2 million, depending on the year, yielding a total net revenue of $27.4 million available for local purpose during the nine year period. By contrast, assuming a net revenue based on 2020 alone would result in an additional $11.3 million of revenues being available. Using a snapshot year like 2020 instead of analyzing these results annually for 2012-2020 might suggest to policymakers that more dollars might be available for specific programs with policy preference when in fact the dollars are not available.

Figure 4

NCPA Auction Revenue Recycled Under CPUC Preferred Output Case

	NCPA Emissions Costs (MM$)	Auction Revenue Received (MM$)	Net Revenues (MM$)
2012	5.0	8.5	3.5
2013	14.8	17.2	2.4
2014	25.6	25.8	0.2
2015	43.2	48.4	5.2
2016	60.4	60.6	0.2
2017	76.7	77.9	1.2
2018	77.5	82.2	4.7
2019	77.0	82.8	5.8
2020	76.5	80.8	4.3
NCPA Totals	456.7	484.1	27.4

Source: NCPA Model Prepared by R.W. Beck

Linear representations of results are likely to misrepresent the true impacts of certain policy cases, potentially leading to policy recommendations that may ultimately not be in the best interest of California consumers.

3. There are a number of resource assumption details that adds complexity to the use of the model but does not add value to the results being generated.

As an Excel spreadsheet, the 35 megabyte E3 GHG calculator has a significant level of complexity built into its structure, despite the decision to reflect only 2008 and 2020 in terms of results. E3 has done outstanding work addressing stakeholder concerns, documenting model changes, and making a public domain tool available for this proceeding. That said, NCPA asserts that the complexities surrounding the PLEXOS production simulation model has made it difficult for stakeholders to run model sensitivities that include higher levels of renewable resources.

In the context of the E3 GHG calculator, model users are asked to arbitrarily choose from 24 different renewable resource zones across the Western Electricity Coordinating Council (WECC) region, and basically add resources until the required renewable resource portfolio is realized for each of the seven retail provider groups. Doing so makes it impossible for model users to account for the various uncertainties attributed to each zone, such as availability of transmission and resources, as well as the timeframe needed for infrastructure development. It also marginalizes the usefulness of any case testing renewable resource sensitivities.

B. Inputs Q9 (5/13/08)

> 5/13; Q9: 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.

The following are some observations surrounding the input assumptions used in the E3 GHG Calculator.

- Cost Characterizations and Heat Rates - This information comes from the Energy Information Administration (EIA), based on its *2007 Annual Energy Outlook*. It is important to note the following:
  (1) The values are not based on specific technology model, "but rather are meant to represent the cost and performance of typical plants under normal operating conditions for each plant type." The environment that is being proposed in this modeling exercise will not derive typical performance and normal operating conditions.
  (2) Geothermal and hydroelectric cost and performance characteristics should be specific to each site. For example, NCPA owns and operates the last major hydroelectric project constructed in California, with significant levels of debt service still impacting the true cost of operating the facility. By contrast, the values assumed in the E3 GHG Calculator represent the least expensive plant that could be built in Northwest Power Pool Region. For NCPA, the use of the E3 GHG calculator will clearly understate the cost borne by NCPA as it continues to operate its hydroelectric facility.
- Emissions Factor for Unspecified Out-of-State Emissions – The emissions factor used for out-of-state emissions is 1,100 pounds of CO_2 per megawatt hour. While this is an accepted policy statement for California pursuant to Senate Bill 1368, neighboring states are not using similar estimates for resources. As the PLEXOS simulation model addresses the entire WECC region, it is clear that the numerical disconnects between

California and other states in the region will need to be reconciled as statewide, regional, and national programs move forward.

C. <u>Results reported by E3</u>

NCPA appreciates the creation of the Scenario Documentation tab in the E3 GHG calculator. This tab will provide the Joint Commissions with a consistent data set that can be reviewed to look at potential policy considerations.

However, NCPA maintains that the cost impact calculations are clearly over-simplistic. If the individual investor-owned utilities have multiple rate schedules to properly account for costs, it becomes difficult, if not impossible, to use those inputs as a benchmark to derive the implied cost impact of AB32 policies for individual utilities.

VIII. CONCLUSION

For the reasons set forth herein, NPCA notes that the information sough by the Joint Commissions in the referenced ALJ Rulings should be used to base a preliminary recommendation to CARB on matters pertaining to the implementation of a cap-and-trade program for the electricity sector.

June 2, 2008

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rule of Practice and Procedure, I have this day served a true copy of the **NORTHERN CALIFORNIA POWER AGENCY COMMENTS ON ASSIGNED ADMINISTRATIVE LAW JUDGES' RULINGS AND STAFF PAPERS REGARDING RECOMMENDATIONS TO THE CALIFORNIA AIR RESOURCES BOARD FOR THE ELECTRICITY SECTOR** on all parties on the Service Lists for R.06-04-009, on the Commission's website on May 28, 2008, by electronic mail, and by U.S. mail with first class postage prepaid on those Appearances that did not provide an electronic mail address.

Executed at San Jose, California this 2nd day of June, 2008.

Katie McCarthy