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

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)
AB 32 Implementation	CEC Docket 07-OIIP-01

COMMENTS OF THE ENERGY PRODUCERS AND USERS COALITION AND THE COGENERATION ASSOCIATION OF CALIFORNIA ON ALLOWANCE ALLOCATION, COMBINED HEAT AND POWER, MODELING AND FLEXIBLE COMPLIANCE

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COMMENTS OF THE ENERGY PRODUCERS AND USERS COALITION AND THE COGENERATION ASSOCIATION OF CALIFORNIA ON ALLOWANCE ALLOCATION, COMBINED HEAT AND POWER, MODELING AND FLEXIBLE COMPLIANCE

The Energy Producers and Users Coalition[1] and the Cogeneration Association of California[2] (jointly, EPUC/CAC) submit the following comments pursuant to five Administrative Law Judge Rulings dated April 16, May 1, May 6, May 13 and May 20, 2008.

I. SUMMARY

The Commissions should be commended for their aggressive efforts to develop a framework for greenhouse gas (GHG) regulation in California's electricity sector. These efforts, however, far outpace AB 32 program development in other sectors. The Commissions thus should aim for a general conceptual recommendation to the California Air Resources Board (CARB) in August, with ongoing proceedings to refine the proposal as CARB's Scoping Plan begins to take shape.

The Commissions' general recommendations should reflect a cautious approach. Electricity is an essential service, and material restructuring of the industry can have dramatic and adverse consequences, as California experienced in the energy crisis of 2000-01. Introducing a GHG program in the electricity sector, regardless of its design, will be a material change for the industry. Implementing this change with a "big bang", without a reasonable period for stakeholders to adapt, would present risks of unintended

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[1] EPUC is an ad hoc group representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, BP West Coast Products LLC, Chevron U.S.A. Inc., ConocoPhillips Company, ExxonMobil Power and Gas Services Inc., Shell Oil Products US, THUMS Long Beach Company, Occidental Elk Hills, Inc., and Valero Refining Company – California.

[2] CAC represents the combined heat and power and cogeneration operation interests of the following entities: Coalinga Cogeneration Company, Mid-Set Cogeneration Company, Kern River Cogeneration Company, Sycamore Cogeneration Company, Sargent Canyon Cogeneration Company, Salinas River Cogeneration Company, Midway Sunset Cogeneration Company and Watson Cogeneration Company.

consequences for generators, load-serving entities and consumers. Regulators should thus avoid strident program features – significant ratchets on sector emissions and allowance auctions – early in the program implementation.

A focal point of the Commissions' program design should be to incorporate program features that encourage the deployment of valuable and proven GHG reduction tools. Existing programs, such as the renewable portfolio standard (RPS) and energy efficiency (EE) programs will contribute significantly to GHG reduction efforts. In addition, however, these comments highlight the importance and benefits of combined heat and power (CHP) resources as a GHG reduction tool and the inadvertent disincentives to CHP that can result from program design. CHP historically has afforded the state substantial GHG emission reductions as a result of federal and state legislation with development extending from the mid 180s into the early 1990s. Since that time, however, policies encouraging CHP have atrophied, resulting in a plateau in CHP generation. Consequently, an important success in the Commissions' program design and recommendations to CARB would be clear rules to encourage continued CHP operation and development in California.

A. General Issues: Criteria For Evaluation Of Program Alternatives Should Be Expanded To Include Supply Adequacy And Efficiency.

Evaluation Criteria. The Staff Paper identifies criteria for evaluation of allowance distribution schemes. The criteria should be expanded in two respects.

The evaluation criteria center largely on consumer cost, consistent with the Commissions' duty to protect utility ratepayers. Equally important, if not more so, is the short- and long-term availability of supply to consumers. The Commissions' evaluation criteria thus should include the goal of maintaining supply adequacy, undertaking an examination of the potential impacts of GHG program design on the state's electricity supply. As a part of this review, the

Commissions should consider the impact of the proposed allowance distribution scheme on credit, price volatility and wholesale market development. To avoid unintended consequences for the state's electricity supply, the program design proposed by the Commissions should be measured and cautious, avoiding an overly restrictive cap and phasing in any direct costs imposed on generators through auction.

The Staff's evaluation criteria also include the goal of equity among customers of load-serving entities (LSEs); regulators seek to avoid disproportionate rate increases for customers of higher emitting LSEs. In pursuing this objective, however, the Commissions should not sacrifice the goal of encouraging efficient generation. The adopted allowance distribution method thus should balance the goals of equity and efficiency.

B. General Electricity Sector Allowance Distribution

Allocation. Allowances should be allocated to emitting deliverers. In selecting the appropriate method, regulators must balance the interests in protecting existing investment (and thus ratepayers) with the goal of increasing efficient production.

Auction. The lawfulness of an allowance auction remains untested and should be determined within the scope of the broader, multi-sector program. To the extent that an auction is lawful and California's regulators mandate an auction for the electricity sector, the percentage of auction should be phased in at a measured pace to avoid industry disruption and supply constraints. All available allowances would be allocated administratively using the modified OBA for 2012-13. In each of the subsequent two years, allowances would be allocated administratively, with a minimal amount of allowances distributed by auction. At the conclusion of this two-year trial auction, regulators should determine whether and to what extent an increased auction percentage is warranted.

Auction Revenues. Auction revenues, whether retained in the electricity sector or employed on an economy-wide basis, should be targeted to the development and deployment of GHG reduction technologies. In addition, any programs encouraging technology development must be made available to all potential competitors on an equal basis.

New Entrant Reserve. A new entrant reserve should be set aside for new generation. The reserve for the electricity sector should be sized sufficiently to accommodate new generation needs, taking into account load growth, anticipated plant retirements and increased efficiency from repowering. Combined heat and power and other low carbon generation should be given priority in the new entrant reserve to recognize their efficient fuel use and carbon reduction benefits.

C. Combined Heat And Power

CHP as a GHG Reduction Measure. Agency findings and the Commissions' recent E3 modeling results demonstrate that CHP has value as a material, cost-effective GHG reduction tool. California thus should design a GHG program that provides active incentives to encourage continued CHP operation and development of new CHP resources.

CHP Sector. CHP resources should be addressed in a single sector to accommodate the unique characteristics of CHP. For topping cycle CHP, allowances should be brought into the sector both from the electricity and industrial sectors for allocation purposes based on a "double benchmark" calculation. For bottoming cycle CHP, allowances should come from the electricity sector only where the facility employs supplemental firing. The sector should be overseen and regulated by CARB, with reporting to the CPUC or CEC for purposes of monitoring the benefits to the electricity sector.

CHP Allowance Allocation. Allowances should be allocated to topping cycle CHP plants using a "double benchmark" allocation method. The double benchmark allocates allowances based on the emissions that would have occurred had an equal amount of thermal and electrical energy been produced using traditional generator and a boiler. The electric reference in the benchmark should be based on a CCGT emissions rate, vintaged to 2002 technology and adjusted to account for the avoidance of line losses for load served on site. The thermal reference in the benchmark should be based on an 80% HHV efficient boiler. Using a double benchmark approach ensures that CHP receiving policy benefits is more efficient than the alternative and will reward CHP in proportion to its relative efficiency.

For a bottoming cycle CHP, allowances should be allocate only to those plants emitting GHG, based on the electricity reference in the double benchmark formula or the general allocation factor used for other generation resources. In addition, the Commissions should work closely with CARB to ensure that the societal value of bottoming cycle CHP is taken into account for purposes of GHG compliance by the industrial facility installing the CHP.

CHP Carbon Cost Recovery. CHP power sales to the utilities must permit the recovery of carbon costs to ensure operation and new development.

Other CHP Policies. The Commissions should review and augment existing CHP policies to ensure proper incentives are provided to maintain and develop efficient CHP facilities. The policy should provide for ease of interconnection and grid interface, reasonable power sales opportunities, and elimination of departing load charges.

D. E3 Modeling

Despite the inherent limitations of modeling and the compromises struck on several issues, the E3 model provides useful information on the cost and environmental impact of different resources and policies. In particular, the E3 model demonstrates, using conservative assumptions, that, from a utility carbon cost perspective, CHP is among the most cost-effective GHG reduction tools available and offers up to 4.9 MMtCO2e in additional reductions by 2020.

E. Flexible Compliance

CARB observes that "*interest in cost containment arises from the belief that an excessively wide range in allowance price or sudden sharp changes in allowance price (volatility) could be economically disruptive in the short term*." In the electricity sector, where the very thing regulated is a commodity of necessity, it is particularly important to make a wide variety of flexible compliance tools available. In particular, EPUC/CAC recommend consideration of the following flexible mechanisms to facilitate compliance in a cap-and-trade market system: (1) linkage with other GHG programs; (2) a two-year compliance period to allow market participants to learn by doing, followed by a longer, seven year period to provide regulatory certainty; (3) banking across compliance periods; (4) borrowing within compliance periods; (5) broad use of offsets subject to uniform standards and verification.

II. GENERAL ISSUES

A. Designing A Successful Electricity Sector Allowance Distribution Scheme Requires An Expansion Of Evaluation Criteria

The Staff Paper identifies evaluation criteria for allowance distribution alternatives based on AB 32's mandate.[3] It proposes to evaluate alternatives based on their (1) impact on retail electricity customers, (2) equity among customers of retail providers, (3) administrative simplicity and (4) accommodation of new entrants. While the Paper's objectives are well placed, the GHG discussion would benefit from a broader assessment of program goals to include supply adequacy and generation efficiency.

The Commissions should review the potential impact of program alternatives on short- and long-term supply availability. California's AB 32

[3] Staff Paper, Section 2, at 9-12.

program could affect consumers materially if it adversely affects the incentives to operate existing or develop new generation. The Legislature had these concerns in mind in enacting AB 32, declaring that California's GHG program must "*improve[] and modernize[] California's energy infrastructure and maintain[] electric system reliability*." [4] The statute further requires CARB to consult with the Commissions on all elements of the AB 32 plan that pertain to "*electrical generation*" and "*the provision of reliable and affordable electrical service*." The potential for an electricity sector program to affect supply availability and generation development merits strong consideration by the Commissions' in their recommendations to CARB. Section II.B further discusses these issues.

The Commissions should also include the goal of encouraging the efficient use of fossil fuels. The proposed evaluation criteria consider "equity" among customers of different LSEs. The equity concern stems from the potential that customers of high-emitting LSEs may see a greater rate increase in the early stages of program implementation than customers of lower emitting LSEs. While this may be a valid concern, it must be set in balance with the goal of encouraging efficient use of fossil fuels.

B. A Program Design That Places A Material Risk Of Carbon Cost Recovery On Generators Will Threaten The Availability Of Electricity To California Consumers

A critical factor in ensuring a stable supply of electricity in the short and long-run, is the recovery of costs, including carbon costs, by generators. A GHG program design that places a material risk of carbon cost recovery on generators in the program's infancy thus could threaten the availability of electricity supply to California consumers. To date, the Commissions have not addressed the potential supply impact of GHG regulation, which suggests that they assume generators will fully recover their carbon costs in the market. As explained below,

[4] Ca. Health & Safety Code §38501(h).

- Generators' ability to recover carbon costs can impact their profitability and, without cost recovery, generators may choose not to run or invest;

- An assumption that generators will fully recover carbon costs in the market and/or through bilateral contracts overlooks other significant variables and conditions inherent in the current California market;

- Ensuring the recovery of carbon costs is particularly important given the number of other variables that can impact supply reliability; and

- The issue of supply reliability is not adequately addressed in the E3 model or through other GHG program experience.

1. Failure of Generators to Recover Carbon Costs in the Market Could Materially Affect Their Profitability and Viability

In order to remain viable, generators will need to recover costs associated with any required purchase of GHG allowances and investments needed to ensure future compliance with a shrinking state-wide cap. Existing generators will not run if they cannot recover carbon costs, and new generation investment will not be made with non-utility capital if carbon cost recovery is uncertain in the long run. While carbon regulation is in fact aimed at driving certain resources out of the market in the long run, undermining viability in the short run during the program's transition is highly undesirable. As discussed below, carbon cost impact on a generator's economic viability can be significant – even for relatively "clean" fossil generators.

Generators must recover both their variable and fixed operating costs, whether through the spot markets or bilateral contracts. If a generator anticipates that it will be unable to recover its variable costs, including carbon, from energy market revenues over the short-term, it is reasonable to expect that they will shut the plant down in order to limit their operating losses. Similarly, if a generator determines that energy market revenues in excess of their variable operating costs, including carbon, will not be sufficient to cover their fixed costs, they may mothball or even close the plant. It is also entirely possible that suppliers will shut down plants and redeploy personnel and generating assets because of the potential they will lose money, rather than waiting to shut down until they actually start seeing losses. Any potential developer seeing these trends in the market would think twice about further investment.

While it is difficult to fully analyze the effects of carbon costs on bilateral contracts, two examples with administratively determined prices are instructive. Take, for example, a Qualifying Facility (QF) generator with operating and financial characteristics consistent with those adopted in Resolution E-4049, which implements D.07-09-040. A QF with these characteristics would experience a reduction in after-tax cash flows of about 18% and 113% (negative cash flow), associated with unreimbursed allowance costs of $8 and $50/t$CO_2$e, respectively.[5] Likewise, consider a generator paid a contract price equivalent to the CPUC's Market Price Referent (MPR). Using the values from the implementing Resolution E-4090, the following table highlights the potential impact on return on equity (ROE) of carbon allowance costs for generators paid the adopted administrative formula.[6]

Un-Reimbursed GHG Allowance Cost ($/Metric Ton)	Resolution E-4090 Return on Equity (%)	Change In CPUC Adopted ROE (%)
$0.00	12.78%	0%
$5.00	10.92%	-15%
$10.00	8.99%	-30%
$15.00	6.96%	-46%
$20.00	4.82%	-62%
$25.00	2.52%	-80%
$30.00	-0.02%	-100%

In other words, a generator paid a price equivalent to the MPR approved by this Commission – a proxy for today's market price -- would be unprofitable at a

5 The calculation reflects the reduction in the MPR model generated after-tax cash flows assuming the non-reimbursed $/t$CO_2$ cost is reflected at the adopted MPR heat rate and capacity factor.

6 The return on equity percentages in the table are calculated by the adopted MPR model modified such that the GHG costs are reflected as a non-reimbursed expense. The change in ROE is the difference between the adopted ROE at 12.78% and the CO_2 cost adjusted ROE divided by the 12.78% number.

carbon cost of \$15-20//tCO_2e when compared with a risk-free return on treasury bills in the 4.5%-5.0% range. Assuming a carbon price of \$50/tCO_2e, the result for a generator paid under this formula would be a ridiculous negative net cash flow of up to \$88 million over a 20-year period. [7] This analysis presumes that the generator would be able to purchase natural gas at the MPR gas price, an assumption that may not be valid during periods of increased market volatility. If the prevailing gas price is higher than the MPR gas price, the generator's negative cash flows would be even greater.

Although the conventional wisdom suggests only coal plants and older, less efficient gas-fired plants built prior to the 1980s are likely to be affected, in fact relatively new, clean, high efficiency combined cycle plants are also vulnerable. Consider the case of a high efficiency combined cycle plant that produces 800 pounds of carbon per MWh. If it operates at a 65% capacity factor, for each 1 MW of electric capacity, it will produce about 5700 MWh and 2300 tons of carbon per year. At a carbon price of \$50/ton, the generator will have to earn \$20/MWh *over and above* its fuel and variable maintenance costs just to pay the carbon bill. Yet according to an analysis prepared by the CAISO, the average net revenue earned by gas-fired generation in California during 2007 was only \$16.7/MWh[8] -- to sustain operation. If enough generators shut down because prices are too low, the remaining supply of nuclear, hydro, renewable and out-of-state imports will not be sufficient to meet California's aggregate demand for electricity during peak usage periods.

The ability of generators to recover their fixed, variable and GHG costs through their contract prices is critical to ongoing supply adequacy. Steps must be taken by the Commission to increase the certainty of recovery. The most direct route for bilateral contracts is to require as a standard term the pass-through of carbon costs under all utility bilateral contracts. Equally as important, however, is minimizing the actual carbon cost exposure early in the program

[7] *See supra*, n. 12.
[8] California ISO Market Issues and Performance, 2007 Annual Report at 12.

years by limiting the extent of auction. Auction limitations are discussed further in Section III.

2. Regulators' Implicit Assumption that Generators Will Fully Recover their Carbon Costs in the Market Requires Further Examination

It appears that the Commissions have assumed that generators will have no problem recovering the costs required to continue generating power for the state. While this assumption may be reasonable for utility-owned generation, independent power producers (IPP) will not have a guarantee of carbon cost recovery. As NERA noted in a 2007 report, the extent to which a firm can pass costs on in prices depends on:

> *regulatory conditions, exposure to international competition, the degree of imperfections in competition, as well as a range of other complex market interactions that can vary significantly between industries, products and markets. Where there is not perfect competition, or where imports compete, pass-through is unlikely to correspond to full costs.*[9]

GHG program design, the status of existing contracts, the presence of administratively determined prices, the scope of utility RFOs and MRTU implementation all may materially affect a generator's ability to recover its carbon costs from the market. There are no assurances that entities under bilateral contracts – existing or new -- will be able to recoup carbon costs. Likewise, the MRTU contemplates the use of several market power mitigation features that will effectively limit the ability of generators to secure recovery of their costs.

[9] Harison, Klevnas, Radov, and Foss, September 2007, *Complexities of Allocation Choices in a Greenhouse Gas Emissions Trading Program*, NERA Economic Consulting, prepared at the request of the International Emissions Trading Association, at 36.

a) Regulators Have Provided Little Assurance That Generators in Existing or New Bilateral Contracts Will Be Able To Recover Carbon Costs

There is no guarantee that existing bilateral contracts between a utility and generator will allow generators to recover their full cost of carbon. With the exception of utility-owned generation and the new Walnut Creek facility under contract to Southern California Edison Company (SCE), existing utility contracts with IPPs today do not provide for recovery of carbon costs. Those generators in such contracts, to the extent they run through 2012, will have no mechanism through which they can recover (i) costs associated with potential purchases of allowances or (ii) costs related to investments to mitigate future financial exposure.

Likewise, it is not clear how carbon costs will be addressed for new contracts negotiated before or after 2012. Recent events, however, indicate cause for concern. Carbon cost recovery is a major point of dispute in the CPUC's ongoing implementation of its QF program, pursuant to Decision 07-09-040. In addition, PG&E's most recent RFO, which required bidders to bid a price at which the generator assumes the carbon cost risk, also calls into question whether future utility contracts will permit a generator full carbon cost recovery.[10]

If IPPs are unable to contract with the utilities on terms that reasonably assure carbon cost recover, they may gradually be driven from the market. The result will be additional development of utility-owned generation and the erosion of FERC's vision of wholesale competition in the generation market.

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[10] The RFO issued by PG&E on April 1, 2008, addresses carbon costs by seeking bids in two forms. One form of bid assumes that the Seller is to be reimbursed by PG&E for GHG costs as delineated in six-part provision, which includes a GHG mitigation requirement. The second form of bid requires the Seller to take the GHG cost risk and, apparently, to reflect that risk in the bid capacity price. Bidders are required to make an offer in both forms; in other words, a bidder could be required to take carbon cost risks as a result of the RFO.

b) Market Power Mitigation Features of MRTU Could Limit Ability of Generators to Recover Carbon Costs

A key assumption in the Commission's GHG analysis seems to be that a growing fraction of energy will be traded in the CAISO spot market,[11] which will reflect a carbon price as current bilateral contracts expire.[12] This assumption is misplaced. Today, less than 5% of the power required to meet the needs of IOU customers is transacted in the spot market.[13] It is unlikely, in the short run, that this percentage will increase materially, due to the significant percentage of utility-owned generation and long-term power contracts. Moreover, growth in spot market purchases may also be limited in the longer run, given the CPUC's expressed preference for long-term contracting[14] and historical utility procurement patterns.[15]

Even if the assumption of increased spot sales were realistic, recovery of the full facility's cost of carbon is not guaranteed in the MRTU market. As part of the MRTU design, suppliers will be subject to at least two types of administrative

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[11] Before the end of 2008, the CAISO intends to begin operating new energy markets as part of its market redesign referred to as the Market Redesign and Technology Upgrade (MRTU). MRTU will provide an explicit spot market in which buyers and sellers can trade energy for delivery the following day.

[12] *See, e.g.,* D.08-02-033, at 23 ("*The vast majority of DWR contracts are scheduled to expire by 2011.'*"); *see also* 2007 IEPR, at 161 (*"As noted in the 2005 IEPR, many of the state's operating, large-scale combined heat and power systems continue to run under the terms of generation contracts signed during the early 1980s. As these contracts expire, as much as 2,000 megawatts could shut down by 2010."*). It is also noteworthy that the E3 calculator "lever" on the "CO2 Market" sheet, which unless specifically modified by a user defaults to: "Generator sells to the power pool after bilateral contract ends…" setting. Scenarios 1 through 7 reflecting the basic policy alternatives all include this setting.

[13] The NP 15/SP 15 markets include less than 5% of the utility power purchases. D.07-09-040, at 144.

[14] *See* D.07-12-052, at 264 (referencing the 5% limitation on spot market purchases to cover the net short: "*If an IOU exceeds the 5% limit it is required to submit justification in the quarterly compliance filings*"). *See also, Id.* ("*Currently, it does not appear that MRTU will significantly impact the resource planning and the majority of the procurement processes that typically happen in time frames that begin a substantial length of time prior to the day-ahead and day-of focus of the MRTU market changes*").

[15] *See, e.g.,* D.07-12-052, at 197 ("*In the past several years, a number of conventional generation plants have been acquired by the three IOUs as a result of the August 16, 2007 ACR, various unique opportunities, and RFO selections (i.e., PSAs, EPCs, and PPAs that convert to UOG at the end of the PPA term – there have been no utility-build offers in IOUs' solicitations to date).")*

price controls that may prevent recovery of carbon costs. First, suppliers' bid prices will be subject to a system-wide cap when MRTU goes into effect. In addition to the system-wide bid caps, the MRTU markets will cap a supplier's bid under certain circumstances. Both of these caps could hamper carbon cost recovery by generators. The CAISO "must offer" requirement may not be sufficient to compensate a generator run at capped prices, eroding profitability and threatening the generator's viability.

(i) System-wide bid caps

MRTU system-wide bid caps will be set initially at $500/MWh.[16] While it is intended that the bid caps will gradually be raised over time, the design of the bid caps and subsequent increases neither contemplated nor included any consideration of new carbon costs. Simply stated, the MRTU market has not been designed to ensure recovery of carbon costs.

Consider the following scenario. Under naturally occurring conditions, such as a hot summer with robust electric demand throughout the West that follows a winter season with abnormally low precipitation, wholesale electricity prices could very conceivably approach the bid cap even without carbon costs. To the extent this occurs, suppliers may be unable to make spot market sales without incurring operating losses if the combination of their fuel, operating and maintenance, and potentially sizable carbon costs exceed the capped bid prices. The result will be that generators may choose not to run due to uneconomical conditions. As a result, California could see a repeat of the problems in 2000-01.

While other, parallel WECC spot markets without these administrative bid caps may exist, bid caps in the CAISO market are nevertheless expected to drive prices in the parallel markets. This is because there is no incentive for a buyer of energy to pay significantly more in a parallel spot market if it can buy its energy

[16] FERC Order conditionally accepting the California Independent System Operator's electric tariff filing to reflect market redesign and technology upgrade, September 11, 2006, p. 11.

through the CAISO markets at a price that is kept artificially low by the CAISO's bid caps.

(ii) Individual generator mitigation

In addition to the system-wide bid caps, the MRTU markets will cap a supplier's bid under certain circumstances. Unless the supplier is serving a bulk system need or serving an area that the CAISO has studied[17] and deemed to be "competitive", its bids are subject to automatic adjustments that are intended to limit opportunities to exercise local market power. Under the MRTU rules, the supplier's bid is adjusted to a level that reflects its variable fuel costs plus adders for variable operating costs and a limited number of other expenses. This formula-based rate is not designed to reflect carbon costs. Alternatively, the supplier may negotiate a cost-based default bid that reflects costs the CAISO's formula rate does not capture. It is not clear how environmental costs will be treated in these negotiations and whether the default bids will be sufficiently flexible to accommodate changes in GHG allowance prices. It thus is quite possible that suppliers will not be able to fully recover carbon costs as part of these negotiations.

(iii) The "Must Offer" Solution

There has been a great deal of discussion in the course of the CAISO's market design process about the ability of California's suppliers to recover their costs. Even in today's environment without carbon costs, the CAISO's many mitigation mechanisms will keep prices at levels that may be too low to allow generators to recover their short run costs. In order to avoid the reliability impacts that would ensue if frequent mitigation caused suppliers to sit on the sidelines, the CAISO has implemented several "Must Offer" mechanisms. These mechanisms aim to induce generators to offer energy in the CAISO's spot markets without affecting prices. Importantly the "must-offer" fails to provide

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[17] Currently, the CAISO has only performed the analysis for locations that are bound by 500 CAISO constraints. The CAISO grid, however, has on the order of ten thousand constraints.

compensation for certain fuel and variable maintenance costs.[18] This combination of prices that are depressed by mitigation and "Must Offer" obligations therefore means many suppliers may already be unable to recover their short-term variable costs.

Before it is submitted to the FERC for approval, every element of the CAISO's markets is subjected to a stakeholder process that provides for extensive debate and discussion. One of the key themes in stakeholder debates about the CAISO's spot markets is whether the CAISO can require a supplier under its Must Offer mechanisms to deliver energy even when the supplier believes spot prices will be insufficient to cover its costs.[19] Requiring suppliers to purchase carbon credits while limiting their ability to recover the cost of those credits through the energy markets or in bilateral contracts exacerbates an already difficult situation.

3. The Wide Range of Existing Uncertainties in California's Electricity Markets Heightens the Importance of Taking a Cautious Approach in GHG Regulation

The importance of assuring a generator's ability to recover carbon costs cannot be overstated in light of the numerous additional factors that can impact system reliability. As demonstrated by the list below, the adequacy of California's electricity supply, in the short run, can be affected by a range of factors that can influence reliability particularly in the summer months. Each spring, the CAISO publishes a loads and resources assessment for the upcoming summer.[20] In the last few years, California's experience with supply adequacy during the summer period has differed materially from the CAISO's supply assessment. This difference arises from a number of uncertainties over

[18] Such as gas offset and imbalance costs and costs of air quality permits.

[19] For example the CAISO has recently filed new provisions for an interim capacity product and is developing new mitigation rules for instances where the CAISO uses its MRTU Exceptional Dispatch mechanism to require a generator to run even when the generator did not participate in the CAISO's spot market or when the owner has determined that spot market revenues won't be sufficient to recover its short-run costs.

[20] The report for Summer, 2007 can be found at http://www.caiso.com/1b95/1b95abb649df4.pdf.

which the CAISO has little control and for which there are no viable short-term remedies:

- Supply is measured against a one-in-two year forecast of peak demand. If, as was the case in 2006, demand is significantly higher than forecast, supplies may not be adequate. In 2006, the peak demand on July 26 exceeded the CAISO's forecast by 4,000 MW – an unprecedented forecast error -- due to unusually hot weather across the West.

- The CAISO's forecast assumes California will be able to import as much as 10,000 MW from throughout the Western US. Although California's transmission interconnections with neighboring utilities may have the physical capacity to import this much power, there is no assurance that California's neighbors will have 10,000 MW of surplus generating capacity to export at times when California needs it. Moreover, fires that result from hot summer weather could cause major transmission lines to be taken out of service when they are needed most.

- The maximum generating capacity of most fossil-fired plants is affected by ambient temperatures. On unusually hot days, peaking plants in particular may not be able to furnish as much capacity as the CAISO expects in its supply forecast.

- Much of California's generating fleet uses natural gas, and most of California's supply of natural gas is imported. Even a temporary supply disruption could result in higher natural gas prices and potentially large reductions in available generating capacity.

- California and the rest of the western U.S. depend on hydroelectric generation for a large fraction of their summer electric supply. As experienced in 2000, an unusually dry winter could lead to greatly reduced deliveries of in-state hydro resources and surplus hydropower from the Pacific Northwest.

- Almost 40% of California's fleet of gas-fired generation is more than 30 years old. These plants are becoming increasingly expensive to maintain and operate, they are comparatively dirty and inefficient, and they suffer from unplanned outages at a growing rate. They are also facing additional limitations on how they operate, such as the State Water Control Board's initiative to eliminate the use of once-through-cooling that nearly all of these plants rely on.

While few of these uncertainties, taken alone, would compromise supply reliability, any combination of them could. For example, an unusually hot summer combined with fires around key transmission corridors in both Northern and Southern California would result in record demand for electricity and limited ability to import power. Many observers have pointed to a "perfect storm" of abnormally low winter precipitation, lack of in-state generating capacity and high demand throughout the west, which set the stage for the activities that led to California's energy crisis. Infrequent but severe heat storms, heavy reliance on imported power and natural gas, an aging generation fleet and strict environmental regulation make California's electric supply more vulnerable to disruption than most states.

Mitigating the potential for these and other factors to affect the adequacy of electricity supplies serving California consumers is one of the main roles of energy regulation. The GHG program design for the electricity sector offers regulators an opportunity to structure the program in ways that directly or indirectly could hinder or benefit the adequacy of the state's electricity supply. Most critically, a generator's inability to fully recover carbon costs in the market could affect its ability to operate in the short-run and its willingness to invest in the long-run. Given the existing variables that can influence reliability, therefore, an examination of reliability issues and a cautious approach to program design is needed to avoid unforeseen outcomes like that experienced during the state's experiment with electrical market restructuring.

4. The Issue of Supply Reliability is Not Adequately Addressed in Either the E3 Model or Other GHG Program Experience

a) E3's Model Does Not Address Impacts of GHG Regulation on Electricity Supply

While E3's model is capable of using different resources to satisfy forecasted load, it does not ensure the availability of these resources. Stated differently, the scenarios run by E3 under the Commissions' direction do not ensure that policy proposals are "feasible" from a supply adequacy perspective, nor are these feasibility elements captured in the E3 calculator. Parties encouraged the CPUC to test the policy outcomes by re-running them in the underlying, more detailed production dispatch model, Plexos, to ensure feasible commitment and dispatch. The process, however, did not provide for any kind of economic “feedback loop” to verify that the resources relied upon in the different scenarios would continue to exist in the various economic scenarios. Furthermore, the original model that underlies the simplified power system representation in the E3 model did not employ a detailed representation of California’s electrical network, and therefore the Reference case, itself, has never been tested to determine whether it ensures the reliability of the grid.

One specific example of a reliability issue that has not been adequately assessed in the course of evaluating GHG policy outcomes is the likely impact of integrating renewable resources. The calculator contains supply curves that allow renewable resources to be added under various scenarios. There are cost curves associated with these new renewable resources, and E3 entertained a large number of public comments on integration. One identifiable problem with respect to wind integration costs is that these costs included in the model did not include improvements to the bulk transmission system or the costs of managing congestion on the bulk transmission system. As a result, the analysis does not ensure that renewable and other resource additions can be delivered to the load for the levels of costs assumed in the model. For this reason, should some of the Commissions’ policies be implemented, the California grid could see too much generation in generation pockets and too little supply in load pockets. This is one example of reliability impacts not fully assessed as part of the Commissions’ examination of its proposed policy impacts.

b) The EU-ETS Experience and RGGI Analysis Do Little to Inform the Potential Impacts of GHG Regulation on Supply Adequacy

While it could be argued that the European experience supports the conclusion that GHG regulation will not affect supply adequacy, this result may not hold for California under a scenario in which allowances are auctioned.

Critical differences in the programs could distinguish outcomes. Most importantly, EU Member States initially allocated virtually 100% of available allowances for free based on historical emissions. In fact, and unfortunately, the EU-ETS also overallocated allowances in the electricity sector. Consequently, there were no incremental costs to generators that required market recovery. In addition, the market structure in California differs from the model in EU Member States. European power markets enjoy retail competition; California, in stark contrast, suspended retail competition in its infancy in 2001. Less retail competition means fewer LSEs to purchase power; for all practical purposes, a generator's options when building in the service territory of a California IOU are relatively limited. Consequently, there is less liquidity in the California market than would be found in markets with a greater level of retail competition, potentially hampering an IPP's ability to achieve full carbon cost recovery.

RGGI likewise provides no experience to support a carbon cost recovery assumption and, indeed, no meaningful analysis to address the potential for degradation of supply adequacy. Reliability has been an issue that specific stakeholders have raised to the regulators crafting RGGI, although their concerns center primarily on the number of allowances made available.[21] Their concerns are particularly acute given the 100% auction allocation model RGGI is planning to use to distribute allowances. Despite these concerns, the actual final report on the RGGI Auction approach fails to even address reliability concerns – or even to use the word "reliability."[22]

The New York Department of Conservation attempted to address reliability claims in its reply comments on the RGGI auction plan. It concluded:

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[21] *See, e.g., Comments of Edison Electric Institute,* http://www.rggi.org/docs/edison_electric.pdf ; *Comments of AES*, http://www.rggi.org/docs/aes.pdf; *Comments of Independent Power Producers of New York*, http://www.rggi.org/docs/ippny_comments.pdf .

[22] http://www.rggi.org/docs/rggi_auction_final.pdf

> *Regarding reliability, many commenters suggest that the Program might have an impact on electric system reliability; some further allege that the modeling conducted to assess potential impacts on reliability is inadequate. Notwithstanding this, the New York Independent System Operator (NYISO), ICS Consulting, and the Department of Public Service (DPS) each concluded that reliability would not be impacted. Based on their research, these entities all found that no generating facility would be forced to retire as a result of the Program.*[23]

The Department, however, appeared to have misrepresented the NYISO position. The NYISO's 2008 Reliability Assessment includes a two-page section on potential RGGI impacts on the state's system.[24] A NYISO scenario that evaluated reliability impacts of the proposed RGGI program showed the system can comply with the reliability criterion in 2010, *provided* that sufficient emission allowances (a minimum of 52 million tons) remain available to New York generators. The Assessment stated:

> *"Several situations can be postulated that can result in an insufficient supply of allowances after accounting for fuel switching, offsets, and efficiency improvements. For example, a loss of a major nuclear unit would translate into a need for an additional 10 million tons per year of CO2 allowances.*[7] *It is also possible that non-RGGI-affected entities could remove significant quantities of allowances from the New York markets for other purposes. There is a finite number of allowances below which the RGGI affected generators will become energy-limited resources. That is, without sufficient allowances, generators cannot operate to meet bulk power system electricity needs and also comply with the RGGI program."*[25]

The NYISO appears to conclude that if New York meets its RPS goals, there should be sufficient emission allocations available to maintain reliability. However, if these goals are not met, or if hydro or nuclear fails to meet expectations of output, there could be a shortfall in affordable allowances to reliably meet demand.

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[23] http://www.dec.ny.gov/regulations/43558.html .

[24] http://www.nyiso.com/public/webdocs/newsroom/press_releases/2007/RNA_and_Supporting_FINAL_REPORT_12-12-07.pdf

[25] *Id.* at I-26.

There is no experience, globally, to predict what the impacts of GHG regulation could be on California's electricity supply. Neither can California look to other jurisdictions for robust analysis of these potential reliability impacts. Further, California-specific analysis is required to ensure that GHG will not place California in harm's way to repeat the shortages of 2000-01. Detailed analysis is required to identify and mitigate the potential material impacts to California grid reliability.

C. GHG Regulation Carries The Potential To Affect Credit And Commodities Markets, Further Raising The Potential Long-Run Impact On California's Supply Availability

Even if, in the short-run, a generator runs while not fully recovering its costs, the longer term impacts could be the loss of supply. The Commissions would be well-served by examining the interaction of GHG regulation with the credit and commodities markets.

Credit issues stemming from GHG regulation will have a material effect on a generator's viability as a market participant. Fitch Ratings states that *"[t]he ultimate terms of a cap-and-trade program could have broad reaching implications for both the credit quality of the U.S. electric generators as well as the price of electricity*."[26] As stated recently by *Standard & Poor's* Credit Week:

> *It's premature to make rating changes before any federal legislation takes shape; however, the economic cost of compliance will be a key consideration in our analysis. For regulated utilities, the most important credit factor will be the extent to which regulators allow cost recovery. For unregulated power generators, which have more exposure to market pricing, the actual cost of compliance will be a major credit influence.*[27]

Among the factors that will be considered in determining cost of compliance will be the climate change legislation, the details of the cap-and-trade system and the characteristics of the power markets in which companies participate.

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[26] Fitch Ratings, Global Power/North America Special Report, June 19, 2007, at 4.
[27] *Standard & Poor's* CreditWeek, May 23, 2007, at 23.

Consider the position of an IPP in the California market. A fossil-fired generator that is unable to fully recover carbon costs will experience reduced earnings. As discussed above, these circumstances could arise. Because short-term income drives the net present value of an asset, the generator will also experience a reduced asset value. This effect on total asset value will reduce the generator's creditworthiness and, consequently, impair its borrowing potential. Given the high leverage of many IPPs, this could be enough to trigger debt covenants, liquidity problems and bankruptcy.

In addition to credit implications, the overlay of carbon pricing on the entire energy complex will drive increased volatility in the price of energy commodities. With the price of fuels and power becoming more volatile under a climate change regulated power market, the quality of earnings will decrease as the risk of doing business as an IPP increases.

Placing IPPs under financial strain could have broad and long-term effects on market structure. As IPPs experience financial strain, the more financially stable IOUs, which can pass through their GHG costs, may acquire the distressed assets – a phenomenon California has already witnessed. Likewise, if IPPs cannot take on the level of GHG risk imposed by utilities in their RFOs, the utilities may seek to build additional plants. The result could be to continue to concentrate more generation in the hands of the utilities at the expense of wholesale competition. The vision of a vibrant wholesale market held by the Federal Energy Regulatory Commission could be placed at risk.

D. Mitigating The Risks To California's Energy Supply Requires A Cautious, Measured Approach

California will have a number of critical choices in implementing AB 32 for the electricity sector. Most prominently, how many allowances will be made available to the electricity sector? Likewise, to what extent will allowances be distributed by administrative allocation or auction? Finally, to what extent will the flexible compliance mechanisms permit a generator to minimize its costs of compliance? The answers to these and other critical program design questions should be set in the context not just of cost to consumers, but the short- and long-run risks to consumers that would arise if California's electricity supply is impaired. The proposal offered by EPUC/CAC in these comments proposes a measured step into a cap-and-trade program for the electricity sector that will safeguard supply availability to California consumers.

III. ELECTRICITY SECTOR ALLOWANCE DISTRIBUTION

The Staff Paper organized straw proposals for allowance distribution around three general models: (1) allocation based on a generator's historical emissions (grandfathering); (2) output-based allocation (OBA) and (3) auction. The choice of allowance allocation methods must balance the goals of rewarding efficiency while, for a transition period, mitigating disproportionate impacts on existing resources and the load they serve. Regardless of the method ultimately selected, the point of allocation should be the emitting deliverers burdened with GHG program compliance.

The question of whether and how to integrate an auction with an allocation of allowances is complex. To begin with, it remains unclear whether in fact the state has given authority to CARB or any other body to auction GHG allowances. Until that question is resolved at the broader, multi-sector level, proceeding too far along in auction design may not be an efficient use of regulators or stakeholders resources. Assuming, as the Interim Decision requires, that an auction is a lawful and necessary feature of the electricity sector program, the Commissions should consider a phased-in approach. California should learn by doing in the initial two years of the program through administrative allocation, followed by a gradual auction phase-in. As the evaluation of auction alternatives proceeds, assuming legal authority for auction exists, California should assess the extent to which auctions are affecting generator profitability (as discussed above in Section II). Taking this approach best serves California's interest in light of the complete lack of any global experience with GHG auctions. Moving too quickly could have a material, immediate impact on California's energy economy and could erode the state's electricity supply.

Finally, if an auction is mandated, resulting revenues should be used for purposes that promote AB 32's primary objective: GHG reduction. Revenues should be used first for the costs of program administration. Any further use of revenues should be directed toward the development and deployment of GHG reduction technologies, creating a level playing field for access to these funds.

A. Electricity Sector Allowances Should Be Allocated To Emitting Deliverers

The Staff Paper poses questions regarding the point of allocation: should allowances be allocated to emitting deliverers or to other parties, such as retail providers? EPUC and CAC recommend that allowances be allocated to emitting deliverers.

Emitting deliverers are the point of regulation and will bear the compliance obligation – and related costs - in the electricity sector. In recognition of this responsibility, emitting deliverers should receive as a counterbalance any freely allocated allowances. The EU-ETS recognized this relationship, aligning the point of regulation with the point of allocation.

Allocating allowances to parties other than emitters would operate in practice as an auction. Parties receiving free allowances, such as LSEs, would auction or otherwise sell them to the parties bearing a compliance responsibility. As discussed below in Section III.C., imposing a material level of auction on deliverers is both unnecessary in the early years of the program and presents a degree of risk to the industry. Also such a bifurcated distribution of allowances will compromise the goal of a multi-sector market-based cap-and-trade program. For the same reasons underlying the need for caution in implementing an auction allowances should be allocated at the point of regulation.

B. The Commissions Must Balance A Variety Of Objectives In Selecting The Optimal Allocation Method For The Electricity Sector

In selecting a GHG allowance distribution method, regulators must balance the need to protect existing investment (and the consumers they serve) with the goal of driving efficient production. Grandfathering, or allocation based on historic emissions, errs on the side of protecting existing investment. Grandfathering can be oriented toward efficiency to some degree, as Staff has observed, by creating a steeper rate of reduction for the less efficient producers. Performance benchmarking, in contrast, directly rewards efficient production at the expense of older less-efficient investments. Output-based allocation, depending upon its formulation, can offer an alternative between these two bookends (using an average emissions rate) or can simulate grandfathering (using a fuel-specific emissions rate). For any individual emitter, the "right choice" will be driven by its relative efficiency among competitors. For regulators, the right choice will depend upon the desired policy balance.

These comments do not propose a general electricity sector allocation method. Instead, EPUC and CAC, as CHP producers, focus the Commissions' attention to making the right choice for CHP as a GHG reduction tool. Regardless of the approach taken for the general electricity sector, allowances should be allocated to CHP resources in a way that mitigates disincentives and provides direct incentives to operate and develop these resources.

C. If An Auction Is Determined To Be Lawful And Necessary, It Should Be Phased-In

1. Legal Authority to Distribute Emissions Allowances by Auction Is Not Clear

It is unclear whether California possesses the legal authority to auction allowances, as the Commissions have acknowledged.[28] AB 32 provides no

[28] D.08-03-018 did not address the legality of an auction: "Parties disagree as to whether ARB has authority under current statutes to conduct auctions of allowances. This is not an issue that we should, or need to, resolve. If ARB concludes that it needs additional authority in order to

explicit authority for auction. In addition, an auction fails to meet the criteria of a valid tax or regulatory fee. Accordingly, any current attempt by California to auction allowances would be vulnerable to legal challenge.

In order for California to impose a regulatory fee, the cost of an allowance must bear a fair or reasonable relationship to the payors' burden or benefit on the regulatory activity.[29] Under the circumstances, there is little information, aside from market predictions, that CARB can use to assign a market-value to an allowance. Since there is an insufficient basis to assign an estimated allowance value, it would be impossible to demonstrate that use of an auction amounts to a valid regulatory fee.

A valid tax can be imposed on California citizens only when the authorizing legislation is passed by a two-thirds majority of the Legislature or a vote of the people.[30] AB 32 is a statute that required only a majority vote.[31] Accordingly, it does not provide the authority to impose a tax. Under existing legislation, a GHG auction system in California, therefore, would constitute an invalid tax.

The question of legal authority to auction has not been explicitly broached in the broader multi-sector dialogue. A determination on a statewide basis on the legal authority for auction is, without question, a necessary predicate to any electricity sector program design incorporating an auction.

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conduct auctions and distribute auction proceeds consistent with our recommendations, we recommend that ARB seek additional legislation. We would support ARB in this endeavor." See D.08-03-018, at 95.

[29] *San Diego Gas and Electric Co. v. San Diego County Air Pollution Control District,* 203 Cal.App.3d 1132, 1146 (1988); *Beaumont Investors v. Beaumont-Cherry Valley Water District,* 165 Cal.App.3d 227, 235 (1985).

[30] Cal.Const.Art.XIII.

[31] *See* legislative history for AB 32 indicating that bill required majority vote, http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_history.html.

2. The Lack of Auction Experience in GHG and Criteria Pollutant Programs Leaves Proposed AB 32 Auction Vulnerable

Historical support for auctioning even a small portion of allowances is limited. The only jurisdiction to implement a GHG program – the EU – lacks significant experience with auctions, although partial auctions are now under consideration for ETS Phase II. Auctioning in Phase I of the EU-ETS as an allocation method has been applied by only four EU Member States and only to a very limited extent. In Phase I, while the scale of auctioning varied, the maximum auction allocation was 5% of total allocations:[32]

- 5% in Denmark;[33]
- 0.75% in Ireland;
- Hungary has assigned 2.5%; and
- Lithuania 1.5%.

Likewise, U.S. experience with criteria pollutant programs rests almost exclusively with administrative allocations. Since 1995, allowances under the federal Title IV SO_2 Acid Rain program have been allocated administratively for each year with only 2.8% of available allowances auctioned. Meanwhile, allowances under the NOx state implementation plan (NOx SIP Call), which is directed to addressing the reduction of nitrous oxide emissions, have been distributed to incumbent producers at no cost. When the Clean Air Interstate Rule (CAIR) NOx trading program is implemented in 2009, the regulation of NOx emissions will change. The EPA will no longer administer the cap-and-trade programs adopted under the NOx SIP Call Rule. Instead, the CAIR Model Rule contemplates administrative allocation of allowances.

Those jurisdictions which have adopted 100% auction programs under RGGI, such as the State of New York, have not yet implemented an auction and thus provide no relevant experience upon which California can rely. Notably,

32 http://www.climnet.org/euenergy/ET/0506_NAP_report.pdf.

33 It is noteworthy that in the end, 5% was not actually auctioned but instead sold at predetermined prices.

New York (the largest emitter in RGGI) recently revealed that due to changes to its regulation, it may not be able to participate in the September 10 initial RGGI auction.[34] New York's withdrawal would significantly limit the size of the auction and thus limit the scope of RGGI's experience with auctioning and its impacts on regulated entities.

3. A Transition Period Will Mitigate the Potential for Unintended Economic Consequences from a "Big Bang" Auction

The energy crisis of 2000-01 resulted in significant costs and reactionary regulations in the state of California. The Commission must keep this experience in mind as it considers allowance allocation methods, particularly the use of auctioning. Introducing 100% auction of emissions allowances would amount to a "big bang" with a detrimental impact in California's electricity industry ranging from more than a half a billion dollars to more than 5 billion dollars.[35]

Generators could experience material reductions in after-tax cash flow if compliance responsibility ultimately rests with the GHG emitter and carbon costs cannot be fully recovered in prices. For example, a generator with operating and financial characteristics consistent with those adopted in Resolution E-4049 would experience a reduction in after-tax cash flows of about 18% and 113% (negative cash flow), associated with un-reimbursed allowance costs of $8 and $50/MTCO_2$, respectively. It is impossible to predict precisely how the industry

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[34] "New York Could Miss First RGGI Auction." Carbon Market North America, Vol 3, Issue 10: 2-3, May 21, 2008

[35] California's electricity sector accounts for approximately 20% of the state's GHG emissions, or roughly 100,000,000 metric tons of CO2. (CARB Draft GHG Emissions Inventory: http://www.arb.ca.gov/cc/ccei/inventory/tables/rpt_inventory_ipcc_all.pdf) Assuming an auction achieving the CPUC's $8 carbon adder price, the sector-wide impact would be approximately $800,000,000. Taking a higher forecast of carbon value of $40-$50 MTCO2 would yield a range of $3.85 to $5.0 billion. See *Oxford Economic Forecasting* (2006): 'DTI Energy Price Scenarios in the Oxford Models', available at http://www.berr.gov.uk/files/file35874.pdf. Estimates of California carbon values have been as high as $110 MTCO2. *See Program on Technology Innovation: Economic Analysis of California Climate Initiatives: An Integrated Approach*, Volume 1: Summary for Policymakers, at 3-13.

would respond to such a dramatic change but significant reductions in an entity's cash flow is certainly not an incentive for continued operation.

The cost impact of auctioning is of particular concern to independent generators selling electricity to utilities pursuant to existing contracts. While utilities may be allowed to pass the costs of compliance on to their ratepayers, there may be an issue as to whether an independent generator may pass the costs on to the purchasing utility.

Regulators, however, can mitigate the potential negative economic impacts on obligated entities through a gradual movement towards increased auctioning. Since the true impact of an auction will not be known until it is implemented, the Commission should recommend a conservative approach using a reasonable transition period.

4. California Cannot Risk the Erosion of its Electricity Supply in an Imperfect Carbon Market

Section II of these comments discussed the potential impacts of GHG regulations on supply availability to the California market. While the long-range goal of AB 32 may be to shut down higher-emitting resources, an auction could accelerate this result in the short-run if allowance costs result in unprofitable operations. An auction will also likely affect long-term resource development for the California market. Finally, an auction will also likely affect resources that are not designated as higher-emitting resources.

It is impossible to know in advance of implementation precisely how an auction will affect power producers. Suffice it to say, however, the potential exists for a full auction to materially affect supply availability – a consequence the state cannot afford. The risk of a detrimental impact, however, can be mitigated by a measured approach to GHG program implementation. It would be prudent to provide generators a period to gain experience with the trading and compliance processes before being exposed to carbon costs. Additionally, phasing in the percentage of auction over time gives additional time for generators to work toward compliance objectives without untenable financial exposure. EPUC and CAC recommend that if an auction is employed for the electricity sector, the program should begin with two-years of full administrative allocation. In 2014-2015, auction percentages should be minimal. In 2016, regulators should determine whether and to what extent an increased auction percentage is warranted.

5. Regulators Have Tools to Mitigate the Potential for Windfall Profits in the Phase-in Period

The use of auction has become a popular answer both nationally and internationally to the fear that an administrative allowance distribution will "overcompensate" regulated firms for costs incurred under a GHG program.[36] As the MAC Report observes, there can be little doubt that this phenomenon occurred in Phase 1 of the EU-ETS.[37] Concern regarding windfall profits alone, however, should not drive decisions on the distribution of emissions allowances in the electricity sector. California, unlike the EU, possesses many regulatory tools to limit any such result under an administrative allocation. Regulators must also remember that allowances were over-allocated in the Phase 1 EU-ETS allowance distribution.

The price for energy and capacity from the majority of resources serving California consumers falls under state regulatory oversight. For example, the ownership classification of 2005 electrical generation of 287,977 GWh[38] of power produced indicates the following:

- √ The CPUC controls directly the pass through of costs for power sold from investor-owned utility generation, which accounts for roughly 23% of the state's annual generation.

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36 NERA at 36.

37 MAC Report at 56.

38 The data, which were not readily available in a useful form, were compiled using public data from the California Energy Commission and the Energy Information Administration.

√ Local governments and state agencies control the costs passed through to consumers by publicly owned utilities, which account for about 16% of the state's generation.

√ The CPUC administratively determines the price paid for power generated by Qualifying Facilities (QFs) under PURPA and the recent program adopted in Decision 07-09-040. In addition, power generated by QFs that is not sold to the grid is self-supplied with no risk of "windfall profits." Likewise, prices paid to renewable resources are also subject to regulatory oversight. Consequently, regulators have adequate tools available to mitigate the risk of windfall profit-taking by QF and renewable power, which accounts for roughly 22% of the state's generation.

√ The only areas in which a risk of potential for windfall profits might arise are in-state merchant generation and imported power. However, to the extent these resources are committed to long-term bilateral contracts for sale to the investor-owned utilities the CPUC holds jurisdiction to regulate how the carbon value is reflected in the price paid by the utility.

CALLIFORNIA 2005 ELECTRICAL ENERGY GENERATION

TOTAL PRODUCTION, BY RESOURCE TYPE

(Gigawatt Hours)

	Generation Ownership Classifications					
Fuel Type	**IOU[a]**	**Muni[a]**	**Governmental & Irrigation Dist[a]**	**Non-CHP QFs, Independent & Merchant[a]**	**CHP[a]**	**Total[b]**
Hydroelectric	17,633	7,525	14,374	358	0	39,891
Nuclear	36,155	0	0	0	0	36,155
Coal	12,440	11,482	0	1,035	3,173	28,129
Oil	26	2	3	42	75	148
Gas	1,079	10,807	1,153	46,458	36,550	96,047
Geothermal	0	0	1,039	13,340	0	14,380
Organic Waste	0	943	0	3,303	1,780	6,027
Wind	0	35	0	4,049	0	4,084
Solar	0	2	0	658	0	660
Other	0	0	0	0	0	0
Energy Imports						62,456
Total Generation:	67,333	30,798	16,570	69,243	41,577	287,977
Percent of Total:	23.4%	10.7%	5.8%	24.0%	14.4%	100.0%

[a]Ownership Classifications derived from data reported to the U.S. Department of Energy, Energy Information Administration (EIA) for 2005 (EIA-906/920 Monthly Time Series File)

[b]Total 2005 GWh of production by resource type compiled from California Energy Commission (CEC) generation data posted on the CEC webpage.

In stark contrast, EU member states had little or no control over the prices at which power was sold, either at wholesale or retail, as the EU electricity market was liberalized and there were no regulated price control mechanisms in place. This is still the case today.

Beyond the broad scope of regulatory price control, other measures can be used to mitigate the potential for windfall profits. As discussed in Section III.A, the use of a modified output-based allocation, which would allocate allowances to generators based on the lower of their actual or an average emissions benchmark, would provide a degree of mitigation for price increases and windfall profits. Further mitigation could be achieved using some form of updating or true-up annually, to limit the potential for excess allowances being provided.

There is no doubt that some risk exists that generators may seek or take windfall profits if emissions allowances are allocated administratively, and that a wealth transfer could occur from ratepayers to unregulated generators. That risk, particularly when mitigated through regulatory oversight, is outweighed by the risk of a "Big Bang" auction to California's power supply and economy.

D. If Auctioning Is Mandated, Revenues Should Be Directed To Achieve AB 32's GHG Reduction Goals

The Staff Paper contemplates retention of a large share of any auction revenues for consumer benefit in the electricity sector. The Paper provides three grounds for this approach:[39]

- Electricity consumers in California are currently paying, and will be paying, public goods charges that are directly climate-related;
- Electricity is a vital commodity, and allocation of GHG auction revenues to low-income ratepayers could mitigate upward rate pressure that will result from carbon costs.
- Regulated utilities have oversight by the CPUC or their local governing boards and can be held accountable for spending their funds in a manner directed to meet AB 32 goals.

It is difficult to argue with Staff's observations, and as utility customers, EPUC and CAC members could be in line to benefit from the use of revenues for rate reductions or reductions of the public purpose program charges. Nonetheless, EPUC and CAC submit that the best and most appropriate use of any auction revenues would be to further the ultimate goal of AB 32: GHG reduction.

Auction revenues, whether retained in the electricity sector or employed on an economy-wide basis, should be targeted to the development and deployment of GHG reduction technologies. In addition, any programs encouraging technology development must be made in a competitively neutral manner.

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[39] Staff Allocation Paper at 36.

E. A New Entrant Reserve Should Be Created With Priority Access Provided To Low Carbon Resources

The Staff Paper rightly recommends that program alternatives provide for the set-aside of allowances to accommodate new entry into the generation market. Any amount of reserve proposed today would be arbitrary. Instead, the reserve should be sized sufficiently to accommodate new generation needs, taking into account load growth, anticipated plant retirements and increased efficiency from repowering. The average OBA, as proposed in these comments, should naturally result in an excess of allowances above allocation, which could be used as a foundation in the new entrant reserve. Combined heat and power and biomass generation, along with other low-carbon resources, should be given priority in the new entrant reserve to recognize the carbon reduction benefits of these technologies.

IV. CHP IS AN EMISSION REDUCTION TOOL THAT REQUIRES CAREFULLY TAILORED ALLOCATION RULES

A. CHP Will Be An Indispensable Tool In The State's Efforts To Achieve AB 32 Mandates

AB 32 requires that the state achieve "*the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions . . . by 2020 . . . .*"[40] CHP is one tool that the state cannot afford to ignore in its efforts to achieve this mandate. The benefits of CHP as a GHG reduction tool are undeniable. Historically, California has provided at least 7.0 $MMtCO_2e$ and up to 26 million tons of CO_2e reductions annually as a result of CHP installations under the Public Utility Regulatory Policies Act of 1978.[41] The CEC also estimates that new CHP can bring an additional 9-11$MMtCO_2$.[42] The Commissions' modeling efforts have also demonstrated that CHP can bring not only substantial emission

40 Ca Health & Safety Code § 38561.

41 18 C.F.R. § 292.301 et seq.

42 These emissions savings can be achieved under the high deployment scenario discussed in the CEC's report entitled "Assessment of California CHP Market and Policy Options for Increased Penetration", dated July 2005. *See also* Economic and Technology Advancements for California Climate Solutions, Discussion Draft (Nov. 15, 2007) at 4-9.

reductions but that CHP represents one of the lowest cost options on the supply curve of GHG reduction. These factors together demonstrate that an electricity policy that fails to adequately recognize the contribution of existing and new CHP resources to GHG reduction efforts will not fulfill the mandates of AB 32.

1. Historical GHG Savings From CHP Are Substantial

It is irrefutable that existing CHP has provided California with substantial GHG savings. Estimated conservatively, annual GHG emissions savings can range from 7.0 $MMtCO_2e$ to 8.8 $MMtCO_2e$.[43] As EPUC and CAC's witness demonstrated in the Long Term Procurement Proceeding (LTPP): "*Existing facilities have calculated annual historical CO_2 emission reductions of over 8.6 million metric tons a year and an associated annual natural gas savings sufficient to supply as many as 5.1 million California residential customers.*"[44]

EPUC and CAC in the LTPP provided a table, summarizing the calculation of the approximate annual average natural gas savings that the State has historically received from California CHP projects based on publicly available data. Natural gas savings, in the production of both thermal and electric energy, total over 245,800,000 MMBtu. As Mr. Ross testified on behalf of EPUC and CAC: "*This represents enough natural gas savings to generate about 33,200 GWh of electrical energy in combined-cycle facilities operating at a 7,400 Btu/kWh heat rate.*"[45] A table supporting these estimates is provided below. These significant CO_2 emission reductions provided by existing CHP, if lost, would conservatively increase the CO_2 reduction target by as much 8.8 $MMtCO_2e$, or 5%.

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[43] See table entitled Approximate Historical Natural Gas Savings From Existing CHP (Section A(1)).

[44] R.06-02-013, Ex. 75, Vol. 1, p. 3 (CAC/EPUC testimony, Ross/Schoenbeck) (assuming an overall CHP 80% lower heating value efficiency and an overall industrial boiler efficiency of 89%).

[45] *Id.*, at 36.

Approximate Historical Natural Gas Savings From Existing CHP

Line	Description	2003 SCE Data All CHP Quantity	2003 SCE Data Larger, More Efficient Oil & Gas CHP Quantity
1	**Assumed CHP LHV Thermal Efficiency:**	73%	80%
2	**Assumed Industrial Boiler LHV Thermal Efficiency:**	89%	89%
3	**CA CHP Displaced Gas Fired Powerplant LHV Thermal Efficiency:**	36%	36%
	CA Natural Gas Savings Solely From Natural Gas-Fired CHP		
4	Annual Gas Savings vis-à-vis Separate Electric and Thermal Production in MMBTU	132,109,659	165,762,277
	Emission Reductions Solely Attributable to CA Natural Gas-Fired CHP		
5	Reduced CO2 in Metric Tons	7,071,097	8,872,335
6	Reduced SO2 in Metric Tons	64	81
7	Reduced NOx in Metric Tons	9,626	12,079
	CA Equivalent Natural Gas Savings from All Cogeneration		
8	Annual Gas Savings vis-à-vis Separate Electric and Thermal Production in MMBTU	132,109,659	165,762,277
9	Equivalent Gas Savings from Non-Natural Gas CHP Generation in MMBTU	80,053,045	80,053,045
10	Total Estimated Equivalent Natural Gas Savings form Cogeneration in MMBTU	212,162,704	245,815,322
	Impact of CHP Natural Gas Saving On CA Electric Energy Production and Consumption		
11	Annual Equivalent Generation From Gas Savings (Estimated at 7400 Btu/kWh Heat Rate) in MWh	28,670,636	33,218,287
12	Equivalent Generation Capacity (at 80% Capacity Factor) in MW	4,091	4,740
13	Percent of Total Generation From CA Electric Utility Owned Generators Reported in 2005	32.1%	37.2%
	Impact of Cogeneration Natural Gas Saving On CA Electric Energy Consumption		
14	SCE & PG&E Average Annual Residential Electric Energy Consumption in MWh	6.5	6.5
15	California Residential Homes Served by Generation Fueled with Gas Saved by Cogeneration	4,410,867	5,110,506

Existing CHP continues to offer significant CO_2 emissions reductions benefits, even when compared against the most modern combined cycle gas turbine (CCGT) facility. Specifically, larger oil and gas industry CHP facilities are much more efficient than separately generated electric and thermal energy. The following table shows a comparison of SCE data for the oil and gas industry with the separate electric and thermal production, based on 2003 actual reported thermal efficiency for the new La Paloma CCGT. The table demonstrates that relative to the La Paloma CCGT, an average oil and gas industry CHP in the SCE territory can save 19,111,582 MMBtu of fuel which results in 992,332 tCO_2e of annual emissions reductions.

	Comparison of Separately Produced Electric and Thermal Energy With SCE Selected Projects from the Oil and Gas Industry	
Line	**SCE May 7, 2007 Presentation Data for Oil & Gas Industry CHP**	**2003 Actuals**
1	Electricity Produced (kWh)	11,847,453,067
	Electricity Produced (MWa)	1,352
2	Thermal Output (MMBtu)	60,618,976
3	Fuel Used HHV (MMBtu)	143,942,325
4	Overall Efficiency (LHV)	**78%**
	Separate Electric & Thermal Production (HHV)	**La Paloma Heat Rate**
5	Electric Generation Heat Rate (Btu/kWh)	7,367
6	Boiler Efficiency	80%
7	Fuel for Thermal Output (MMBtu)	75,773,720
8	Fuel for Electricity Produced (MMBtu)	87,280,187
9	Total for Electricity + Thermal (MMBtu)	163,053,907
10	**Overall Efficiency of Separate Production (LHV)**	**68.5%**
11	**a. Electric Generation Efficiency (LHV)**	**51.2%**
12	**b. Thermal Efficiency (LHV)**	88.4%
13	**Actual QF Cogen Savings (MMBtu)**	19,111,582
14	**QF Cogen Natural Gas Savings as % of Line 11**	12%
	Impact of CHP Natural Gas Saving On CA Electric Energy Consumption	
15	Annual CHP Natural Gas Savings (MMBtu)	19,111,582
16	Equivalent Generation at 7367 Btu/kWh	2,594,215
17	**Customers Served (at 6.5 MWh/Customer-year)**	**399,110**
18	Percent of SCE total residential customers	9.5%
	Reduction in Emission Attributable to CHP Natural Gas Savings	
19	Reduced CO2 in Metric Tons (at 135 Lbs/MMBtu)	**992,332**

Regardless of the estimate used for historic GHG savings from existing CHP, it is clear that the savings have been considerable. The significant CO_2 savings provided by CHP are further reflected in the E3 modeling results.

2. CHP Benefits Are Well-Recognized

The GHG reduction benefits of CHP resources are well-recognized by several agencies and committees that are devoted to examining environmental issues and policies:

- *ETAAC Report*: Cal EPA's ETAAC Committee efforts are directed to identifying and making recommendations regarding activities that will facilitate emissions reductions. Its report recognizes CHP's ability to "*avoid transmission bottlenecks, decrease transmission losses and provide other operational benefits*." [46] As part of its effort to identify such investments, it recommends the promotion of CHP projects that will contribute to lower GHG emissions and criteria air pollutants.[47]

- *CEC's Integrated Energy Policy Report*: The IEPR observes that CHP resources use fuel efficiently, minimize transmission and distribution line losses and will be important in the state's effort to lower GHG: *The importance of keeping this distributed generation capacity in the system is elevated by the state's need to reduce greenhouse gas emissions as part of AB 32. Combined heat and power in particular offers low greenhouse gas emissions rates for electricity generation taking advantage of fuel that is already being used for other purposes. The systems use waste heat for either process or electricity generation needs which results in very efficient use of fossil fuels. Large combined heat and power units appear to offer the greatest fuel efficiency of available distributed generation technologies. Because combined heat and power systems are located close to the load, transmission and distribution line losses are minimized, further reducing greenhouse gas impacts*.[48]

- *CEC's Report on CHP Market Potential*: The CEC estimates that emissions savings from a high deployment of CHP resources can be as high as 9-11 $MMtCO_2$ in annual savings.[49]

- *NARUC*: NARUC's recently adopted resolution reflects several CHP benefits: "*The deployment of CHP and waste-energy recovery technologies increases generation efficiency, reduces fossil-fuel consumption, enhances generation diversity, and has the potential to*

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46 Recommendations of the Economic and Technology Advancement Advisory Committee Final Report on Technologies and Policies to Consider for Reducing Greenhouse Gas Emissions in California, at 4-4.
47 *Id.*
48 CEC 2007 IEPR, at 209.
49 Assessment of California CHP Market and Policy Options for Increased Penetration, dated July 2005.

improve system reliability, decrease line losses, reduce grid congestion, and reduce emissions of air pollutants and greenhouse gases . . . ."[50]

- *Joint Energy Action Plan 2008 Update*: The EAP 2008 Update recognizes the value of CHP resources to the state's efforts to lower GHG emissions: "*In addition, new combined heat and power applications could play a large part in avoiding future greenhouse gas emissions due to the combined efficiency of the heat and power portions of the project".*[51]

Given such a wide range of support and recognition, state GHG policy cannot afford to exclude or compromise the value of these resources.

CHP has also gained recognition across the globe as a material GHG reduction measure. The International Energy Agency explained in its March 2008 Report, *Combined Heat and Power: Evaluating the Benefits of Greater Global Investment*:

> *At their 2007 Summit in Heiligendamm, G8 leaders called on countries to "adopt instruments and measures to significantly increase the share of combined heat and power (CHP) in the generation of electricity." As a result, energy, economic, environmental and utility regulators are looking for tools and information to understand the potential of CHP and to identify appropriate policies for their national circumstances.*

The Report confirms "*that CHP merits a closer look by policy makers as they investigate paths toward a lower-carbon, more efficient, lower-cost and reliable energy future*." IEA concludes:

> *● CHP can reduce CO2 emissions arising from new generation in 2015 by more than 4% (170 Mt /year), while in 2030 this saving increases to more than 10% (950 Mt / year) – equivalent to one and a half times India's total annual emissions of CO2 from power generation. CHP can therefore make a meaningful contribution towards the achievement of emissions stabilisation necessary to avoid major climate disruption. Importantly, the near-term reductions from CHP can be realised starting today offering*

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[50] NARUC Resolution to Encourage the Use of Combined Heat and Power, including the Recycling of Waste Energy, adopted February 20, 2008.
[51] Joint Agency EAP 2008 Update, at 15.

important opportunities for low- and zero-cost GHG emissions reductions.

● Through reduced need for transmission and distribution network investment, and displacement of higher-cost generation plants, increased use of CHP can reduce power sector investments by USD795 billion over the next 20 years, around 7% of total projected power sector investment over the period 2005 - 2030.

● If the energy saving and capital cost benefits of CHP are allocated to its electricity production, growth in CHP market share can slightly reduce the delivered costs of electricity to end consumers. This is contrary to the common view that CHP and other decentralised energy solutions result in higher electricity costs to consumers.

Recognizing these benefits, some EU Member States have created a separate CHP sector, including Finland, Hungary and Poland (Phase 1)[52] and the UK (Phase 2).[53] Other EU Member States, while not creating a separate sector, have recognized the need for separate treatment, including Germany, Austria and Italy.[54] Germany, for example, distributes allowances to CHP using the double benchmarking method described in these comments.

3. E3 Modeling Results Reflect Benefits of CHP as an Emission Reduction Tool

The E3 model reflects the emission reduction potential and cost-effectiveness of CHP resources. In fact, despite relying on very conservative assumptions, the E3 model reveals that from a utility carbon cost perspective, CHP is among the most cost-effective GHG reduction tools and offers up to 4.9

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52 Delta Energy and Environment, *CHP Policy Assistance - A Report for The Energy Producers and Users Coalition and The Cogeneration Association of California*, dated May 2007

53 *See* March 2007 Presentation of the Department for Environment Food and Rural Affairs (DEFRA) entitled "*CHP in Phase II of the EU ETS*," located at http://www.chpqa.com/html/presentations/defra_chp_in_eu-ets_phase2.pdf. For additional detail related to the EU ETS Phase II allocation methodology is provided on the following website: http://www.berr.gov.uk/energy/environment/euets/phase2/allocation/page27064.html.

54 See DEFRA / Ilex Energy (2005): EU ETS PHASE II: TREATMENT OF CHP. A final report to DEFRA (http://www.ilexenergy.com/pages/euetsphase2-treatmentchp2.pdf). And COGEN Europe Briefing Paper (2004): The European Emissions Trading Scheme: Allocation methods for CHP proposed in draft national allocation plans (http://www.cogen.org/Downloadables/Publications/Briefing_NAPs.pdf).

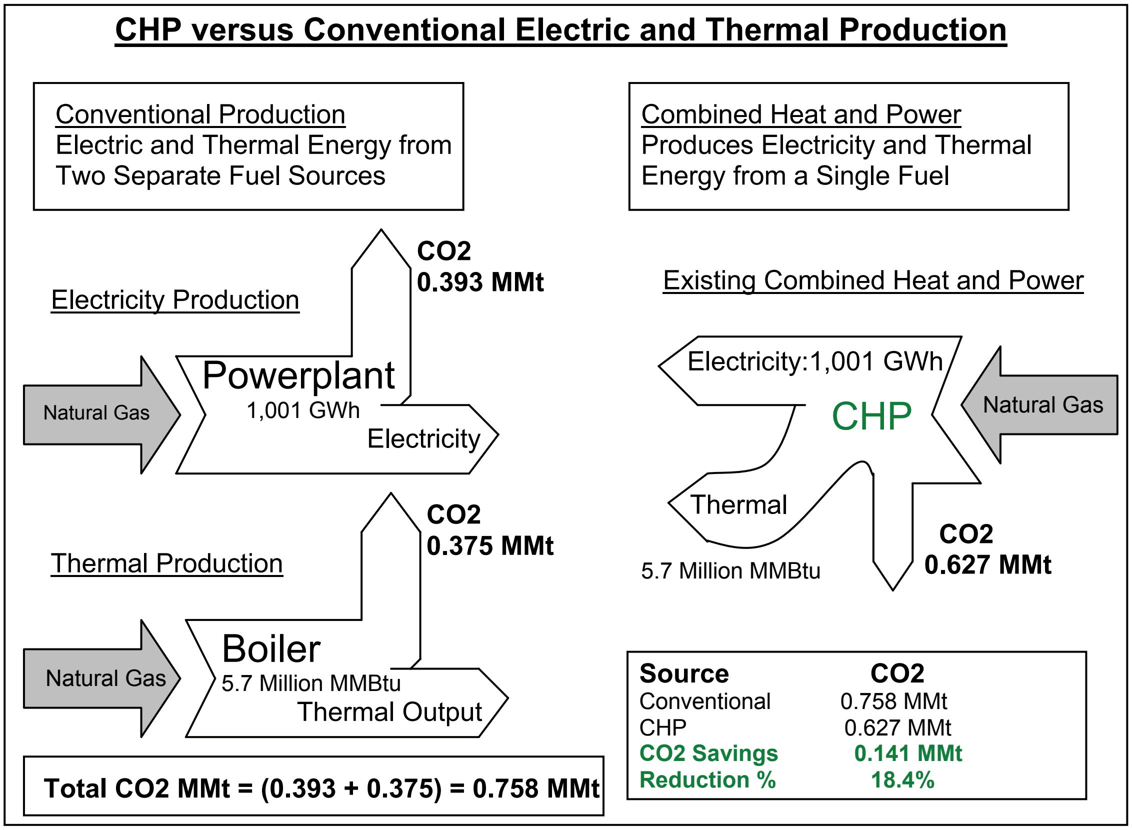
$MMtCO_2e$ in additional reductions by 2020. A full discussion of the E3 model is provided in Section V.

B. California's GHG Must Recognize And Mitigate Disincentives To CHP Retention And Growth

Given the value of CHP resources to the state's GHG policy, regulators must ensure that its GHG program will not discourage CHP. Disincentives can be created either where investment in CHP results in a societal decrease in GHG, but a net increase in GHG compliance costs for the site (topping cycle CHP) or where a resource's ability to generate emission savings is misunderstood (bottoming cycle CHP). Disincentives for both types of CHP are discussed below.

1. Allowance Distribution Methods Can Create Disincentives to Topping Cycle CHP Operation and Development

Allowance allocation can discourage the operation and development of topping cycle CHP facilities. When an industrial site invests in a high efficiency CHP plant, total societal emissions from the production of electrical and thermal energy used by the industrial consumer are decreased. The emissions attributable to CHP will be significantly less than the emissions released as a result of separate central power generation and industrial boiler installations. While *societal* emissions decrease, however, the *industrial site* emissions, are higher, thereby increasing a CHP customer's direct GHG compliance obligation as an emitter. Importantly, because a CHP facility's GHG costs exceed those reflected in utility rates, the investment in CHP does result in a net increase in compliance costs, not merely a shift in expenses.



In this example, an industrial facility producing thermal energy from a steam boiler, and purchasing electricity from an electric utility would cause 0.758 MMt of CO_2 emissions (0.375 MMt of CO_2 emitted on-site and 0.393 MMt of CO_2 emitted off-site by the utility to supply the industrial electrical load). (Note that for simplicity line losses are ignored.) In contrast, if the industrial facility installs CHP, the CHP facility will supply the same amount of thermal energy and on-site consumed electricity but will emit a total of 0.627 MMt of CO_2, with all of the emissions produced on-site. A CHP facility therefore decreases overall emissions by 0.141 MMt (0.758 less 0.627); a reduction of over 18%. While the total emissions are reduced, the emissions produced on-site (and therefore directly attributable to the industrial facility) increase by 0.252 MMt (0.627 less 0.375) or over 67%. Consequently, in an auction system, the CHP facility will need to acquire a significant amount of additional allowances in order to cover the total emissions from thermal and electric production.

The financial effect of this problem has been demonstrated previously by EPUC and CAC,[55] as discussed in the Staff CHP Paper, Section IV. While CHP installation *decreases* GHG emissions attributable to the illustrative customer's energy consumption by 19%, it increases the customer's direct responsibility to obtain GHG allowances by 92%.

One could argue that regardless of CHP investment, a CHP facility covers the carbon compliance costs for its thermal and electric emissions because it would have covered the electricity carbon costs through utility rates. In other words, by installing CHP, a customer would simply be paying for its emissions costs directly at auction, rather than indirectly through utility rates. Investment in topping cycle CHP, however, causes an investing facility to pay for the additional emission costs as a result of two factors:

1. The degree to which utility portfolio carbon costs flow, if at all, to industrial and other consumers through utility rates is a highly complex and uncertain question. The answer will depend upon market design, allocation methodologies and the efficiency with which the market translates the carbon price signal. Moreover, flowing auction revenues back through utility rates, without providing a similar benefit to CHP, would amplify this problem.

2. Even if auction costs were reflected perfectly in utility rates, the auction costs for a gas-fired CHP would exceed the auction costs reflected in the utility portfolio for the California IOUs. The IOU portfolios, particularly SCE and PG&E, contain a mix of nuclear, hydro and renewable resources. Due to the inclusion of these zero-emitting resources, California IOUs have *average* emissions rates – which would be reflected in rates -- lower than the emissions rate for CHP. Thus, although CHP represents a benefit when compared properly to the utility's *marginal resource*, the average cost of carbon faced by a CHP plant likely would be more than the carbon cost embedded in utility rates. As a result, CHP customers in the IOU service territories would pay higher carbon costs for the electricity they produce than if they continued to purchase electricity from the utility.

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[55] *See Comments of the Energy Producers and Users Coalition and the Cogeneration Association of California Regarding Interim Opinion on Greenhouse Gas Regulatory Strategies, Feb. 28, 2008,* at 11.

Consequently, for the CHP facility, there is little reason to believe that the market or ratemaking will eliminate the financial disadvantage created under an auction without regulatory intervention.

The considerable challenge for CHP is to ensure that an allocation system does not penalize new or existing CHP plants. Avoiding an auction of emissions allowances altogether would remove this penalty, assuming a sufficient administrative allocation to CHP plants. Other CHP-specific solutions, including solutions that affirmatively encourage CHP, are addressed in Section (E) below.

2. Bottoming Cycle CHP Presents Unique Design Considerations Under a Cap-and-Trade System

Bottoming cycle CHP plants, like topping cycle plants, involve both heat and power in the interface of a manufacturing process and electricity generation. Consequently, bottoming cycle plants sit astride the electricity and industrial sectors for purposes of GHG regulation. The failure to fully understand the nature of these facilities in a GHG program can discourage their operation and development.

Bottoming cycle plants were labeled as "cogeneration", or CHP, under the Public Utility Regulatory Policies Act of 1978.[56] It may be this label that often causes confusion about the operation of these plants. While topping cycle CHP produces both electrical and thermal energy sequentially, bottoming cycle plants produce only electrical energy, using waste heat from a manufacturing process. In this process, manufacturing waste heat, which would otherwise be vented into the atmosphere, is instead sent to a waste heat boiler where steam is generated to turn a steam turbine and generate electricity. Bottoming cycle units thus may be better understood as pure energy efficiency, or "recycled energy plants", as labeled by the U.S. Clean Heat & Power Association.[57]

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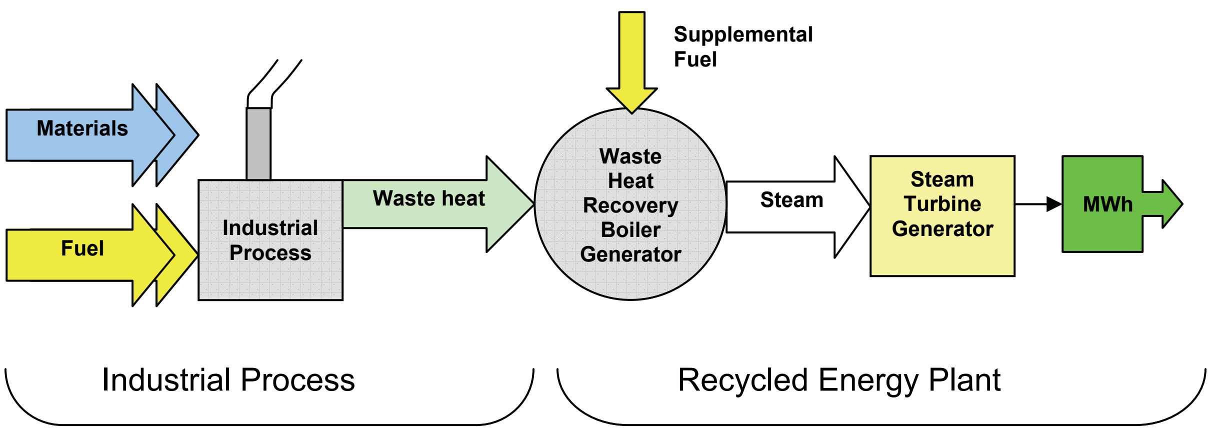
56 18 CFR §202(e).

57 http://www.uschpa.org/i4a/pages/index.cfm?pageid=3283.

The emissions in the case of a bottoming cycle or recycled energy plant are associated with the industrial process. "But for" the industrial process, these emissions would not exist and the addition of the recycled energy plant does not typically add emissions. The only way emissions can be added by the installation of a recycled energy plant is if supplemental fuel is added to fire the waste heat recovery boiler to make additional steam. In that case, the emissions associated with the added fuel are directly associated with the production of electricity. The process can be depicted as follows:



What unique challenges does this type of generation introduce into a GHG program? The plant emissions belong in the industrial sector, but the MWh produced do not. In other words, the industrial process emitting the waste heat (e.g., cement production, petroleum coke calcining) will be regulated not in the electricity sector, but rightfully in the relevant industrial sector by CARB. The MWh, however are better suited to regulation in either the electricity sector or, as proposed here, a separate CHP sector.

Why should these facilities – industrial process and electric generation-- be treated in separate sectors, while topping cycle facilities are treated in a single sector? Unlike a topping cycle plant, there are two distinct physical plants, as depicted above. Consequently, if the facilities are placed in separate sectors, there is no need for an arbitrary allocation of emissions, unlike topping cycle

CHP. Moreover, given the predominant nature of the industrial process, it would make little sense to put the industrial plant in the electricity or CHP sector.

Beyond the question of the appropriate sector lies the characterization of emissions from bottoming cycle plants. As discussed above, absent supplemental firing, there are no emissions associated with recycling the industrial plant's waste heat to make electricity. Power generated without supplemental firing thus carries no emissions. If supplemental firing is introduced to the waste heat recovery boiler, the emissions associated with that fuel will carry additional emissions. Power generated with supplemental firing carry an emissions rate equal to the total emissions from supplemental firing divided by the total MWh produced.

These unique considerations must be taken into account in developing an allowance allocation method for the CHP sector. Potential solutions are discussed in Section D.3.

C. The Commissions' GHG Policy For CHP Should Be Based On Efficiency, Not Size

CHP discussions and measures often turn on the question of size. Namely, should large and small scale CHP be treated similarly? Although size distinctions were not made for nearly 20 years of CHP development, these distinctions have found more favor in recent years.

- Small-scale CHP, 5 MW and under, receives the benefit of a standby service waiver, while large scale projects pay the full cost of utility standby service.[58]
- Small-scale CHP, 5 MW and under, receives a waiver for up to 1 MW of departing load charges unavailable to larger scale projects.[59]

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58 Cal. P.U. Code Section 353.13(a); *see also* D.01-07-027 (ordering implementation of the standby waiver for CHP and renewable DG facilities 5 MW and under).

59 D.03-04-030, at 48-49 (exempting facilities under 1 MW from the entire cost responsibility surcharge and ultra clean and low emissions CHP facilities between 1 MW and 5 MW from all cost responsibility surcharge components save the Bond Charge); *see also* D.07-05-006 (expanding the exemption from the entire cost responsibility surcharge to 1 MW of facilities sized 5 MW and under).

- Small-scale CHP, offering annual energy deliveries of 131,400 MWh or less to the utility, may interconnect under simpler state-administered interconnection tariffs, while larger projects have been forced into the CAISO tariffs.[60]

As demonstrated above, state policies selectively provide certain incentives to CHP solely based on the facility's size.

While EPUC/CAC do not seek to erode existing benefits for small CHP, using size as qualifying criteria for incentives detracts from the objectives of AB 32. Stated differently, if the state's objective is to materially lower GHG emissions, policy should favor those facilities, regardless of size, that are capable of greatest fuel efficiency. As the CEC's 2007 IEPR observes:

> *Combined heat and power in particular offers low greenhouse gas emissions rates for electricity generation taking advantage of a fuel that is already being used for other purposes.* ***Large combined heat and power units appear to offer the greatest fuel efficiency of available distributed generation technologies.*** *Because combined heat and power systems are located close to the load, transmission and distribution line losses are minimized, further reducing greenhouse gas impacts.*[61]

Equally noteworthy, the PIER Collaborative Report, produced in 2005, observed that *"[t]here are already 9,120 MW of active CHP in California at 776 sites. Nearly* ***90%*** *of this capacity resides in large systems with site capacities over 20 MW."*[62] To maximize GHG reduction and other environmental benefits, the efficiency of a CHP facility, rather than an arbitrary MW threshold, should be the focus of policy.

There is no reasonable policy basis to provide more favorable treatment to small-scale projects. Greenhouse gas reduction benefits from CHP depend upon efficiency, not size. The higher a project's efficiency, the greater the energy

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60 D.07-09-040, at 122 ("*These new QFs shall interconnect to the utility under Rule 21*.").
61 2007 IEPR, at 162.
62 Assessment of California CHP Market and Policy Options for Increased Penetration, dated July 2005, at v.

savings that result when compared with stand-alone production of heat and power. The higher the energy savings, the greater the GHG reduction benefit delivered by a project. To promote emission reductions, all CHP, large or small, should be judged on the basis of efficiency rather than size.

Staff's CHP Paper reflects support for the use of efficiency data to determine which CHP installations should be encouraged:

> *If CHP is to be considered an emission reduction measure under AB 32, ARB and/or the Commissions would need to determine that the CHP installation actually causes a net reduction in GHG relative to power delivered from the grid. One approach to ensuring this outcome would be the use of an efficiency threshold for CHP installations.*[63]

Staff also correctly observes the benefits of a using a "double benchmark" efficiency test for topping cycle CHP.

> *One method of creating an efficiency threshold is via a double benchmarking strategy. This is when a CHP system is compared to the next best alternative, such as a separate boiler and a combined-cycle gas turbine (CCGT) system. It is possible to calculate the difference in emissions between the amount of GHG emissions that would be emitted with the two facilities, non-CHP system and the amount that would emitted with a CHP unit. … If the CHP facility reduces emissions relative to the separate facilities, the CHP facility could be considered a GHG reduction measure.*[64]

Finally, the Paper contemplates measurement of waste heat recovery, or evaluation of GHG reduction benefits of fuel switching.

EPUC and CAC agree with the Staff's perspective in at least two respects. First, double benchmarking does provide a means of ensuring that a CHP facility achieves savings compared with the stand-alone generation alternatives. Second, waste heat recovery in the form of bottoming cycle CHP must be

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63 Staff CHP Paper at 10.
64 *Id*.

addressed. Possible approaches to track emissions associated with topping and bottoming cycle CHP are addressed below in Section D.

D. CHP Allowance Allocations Require A Separate Method To Reward Energy Savings And Eliminate Potential For CHP Disincentives

1. CHP Is Best Addressed in a Separate Sector

CHP emissions result from the production of two products: electric and thermal energy. Consequently, the emissions straddle two sectors, electricity and industrial. Addressing CHP emissions in two sectors, however, requires the use of an arbitrary factor to allocate the emissions between thermal and electric energy. Two-sector treatment fails to fairly capture the full societal benefits of CHP which can be realized only when the two alternatives, a CCGT and a boiler, are taken into consideration together. To ensure that CHP emission reductions are fairly reflected, CHP should be placed in a single sector for purposes of GHG regulation. Allowances should be brought into the CHP sector from both the industrial and electricity sector. The industrial sector should contribute an amount equal to the thermal emissions that would have been produced by an industrial boiler (e.g, 80% HHV efficiency) for an equivalent amount of thermal energy. The remainder of required allowances should come from the electricity sector based on the emissions of an electric resource reference. This allocation methodology essentially relies on a double-benchmarking. The sector should be overseen and regulated by CARB, with reporting to the CPUC or CEC for purposes of monitoring the benefits to the electricity sector.

A separate sector will break down barriers to further CHP development, ensure proper incentives for CHP operations, and ease administrative burdens. Without this careful step, particularly as regulators approach the question of allowance distribution, the incentive to maintain existing and build new CHP may easily be lost.

2. Allowance Allocation to Topping Cycle CHP Should Provide Reasonable Incentives

The CHP Paper accurately observes that "*there is the potential for the chosen [GHG] regulatory approach to create a disincentive to CHP facilities*."[65] The Paper further asks "*whether the Commissions should encourage additional CHP installations with favorable regulatory treatment or programmatic initiatives*." Without question, regulators' approach to CHP will turn on whether they seek simply to avoid creating disincentives or to encourage CHP operation and development as a GHG reduction measure.

As explained in greater detail in Section IV(A), a substantial basis exists for an unequivocal policy that will affirmatively advance CHP. The following discussion identifies measures that can be employed in the Commissions' CHP policy development within the GHG program.

a) Double Benchmarking with 100% Administrative Allocation

Due to CHP's dual output, it should receive allowances using a double benchmarking approach. Double benchmarking, in general, contemplates a comparison of a topping cycle CHP plant's actual emissions to the emissions that would have resulted had the same amount of electric and thermal energy been produced using stand-alone electric and heat production facilities. To derive the double benchmark, a plant's electric output is multiplied by an electric reference emissions rate, and the plant's thermal output is multiplied by a thermal reference emissions rate. Once the benchmark is calculated, it is compared with the plant's actual emissions for the same quantity of thermal and electric energy. To the extent the plant's actual emissions are less than the benchmark emissions, a CHP has produced "primary energy savings" (PES) equal to the difference. Primary energy savings reflects an equivalent amount of GHG reduction.

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65 Staff CHP Paper at 10. D.08-03-018 also observes the potential for negative consequences: "*We want to avoid unintended negative consequences for CHP, which may be a valuable source of additional GHG emissions reductions in California*." D.08-03-018, at 10.

By allocating allowances to a CHP plant using a double benchmark, the plant receives an incentive for its GHG reduction. A variety of approaches, particularly in the determination of the electric reference, can be taken in crafting the benchmark. The electric reference can vary depending upon the vintage of the electric reference generation, the fuel used, the treatment of grid losses and other factors. The thermal reference varies less, but can be influenced slightly by design elections. In general the thermal reference will be a stand-alone boiler. Two potential approaches that can be used in a 100% administrative allocation are discussed below.

(1) *Average Fossil Generation Benchmarking*

As noted above in the discussion of general allocation methodologies for the electricity sector, an OBA can be developed using an average fossil generation factor. For illustrative purposes, a value of .48 $tCO2_e$ per MWh can be used for the electrical reference;[66] a reasonable thermal benchmark would be .066313 $MtCO2_e$ per MMBtu.[67] A double benchmark for CHP, against which actual emissions would be compared, could be employed using this average fossil value:

$$(.480 \text{ Mt/MWh} \times \text{MWh Output}_E) + (.066 \text{ Mt/MMBtu} \times \text{MMBtu Output}_T)$$

This approach varies the reward to a plant based on the plant's efficiency: the greater the efficiency, the higher the reward. This approach also avoids the need to determine what the marginal generator should be. Note this method has not made any adjustment for the avoidance of grid losses

(2) *CCGT Benchmarking*

[66] This calculation is based on reported 2006 EIA data. While the EIA reflects only in-state emissions, this number is consistent with the average emissions rate calculated from E3 modeling data. Notably, both estimates underestimate emissions. The EIA data fails to reflect the higher-emitting imports largely comprised of coal-generated electricity and the E3 data applies the interim emission performance standard of 1,100 lbs/MWh which also excludes coal imports.

[67] Using an 80% HHV efficiency for a boiler. (1MMBtu Output ÷ 0.80 x 05305 Mt/MMBtu = 0.066313 Mt/MMBtu)

A double benchmark for CHP can also be developed using a more aggressive electric reference. Rather than using the average grid fossil emissions rate, the emissions rate of a new CCGT could be used as the electric reference. This approach would yield a reference of 0.390 $MtCO2_e$ per MWh, which equates to a 46.4% HHV electrical efficiency. The boiler efficiency will be the same as discussed above. A double benchmark for CHP, against which actual emissions would be compared, could be employed using this average fossil value:

$$(.390 \text{ Mt/MWh x MWh Output}_E) + (.066 \text{ Mt/MMBtu x MMBtu Output}_T)$$

This more conservative approach rewards CHP against the alternative of both a large, new CCGT plant and a new boiler. Note this method also does not make an adjustment for the avoidance of grid losses

This conservative double benchmark can, and should be, modified in two respects to better reflect CHP benefits. First, the electric reference should be vintaged for some limited period of time. EPUC and CAC recommend a 10-year vintage. In other words, in 2012, a 1980s vintage CHP plant would be benchmarked against a 2002 electric generation reference.[68] Second, the benchmark should be adjusted to reflect the savings from grid losses that occur with CHP.[69] Grid losses are reduced when a CHP plant serves load on site, reducing transmission and distribution losses that would have occurred had the load been served by the grid. In addition, grid losses may be reduced for CHP power exported depending on the CHP location and the location of the resource displaced by the CHP power. While California electrical line losses in general are greater than 7.0% and may vary depending on loading, ambient conditions and location, EPUC and CAC propose to use, for purposes of administrative

68 The effect would be to reduce the electrical efficiency from 46.4% HHV to 46.1% HHV.

69 The effect would be to increase the MWh of CHP generation to compensate for the line losses.

simplicity, a 3.5% grid loss factor applied to all CHP generation. When all of these appropriate adjustments are made, the benchmark changes as follows:

$$(0.393 \text{ Mt/MWh} \times (\text{MWh Output}_E \times 1.035)) + (.066 \text{ Mt/MWh} \times \text{MMBtu Output}_T)$$

This approach provides a conservative, yet realistic, measure for a CHP benchmark. Again, the reward to a plant for its PES varies depending on its efficiency: the greater the efficiency, the higher the reward.

b) Double Benchmarking With Auction

Scenario (D)(2)(a) (1) and (2) contemplate 100% administrative allocation to CHP, a preferred approach to encourage CHP development. To the extent that an auction is used, the Commissions must make a choice. Recognizing CHP as the most efficient means of burning fossil fuel, should CHP be required to participate in an auction? Mechanically, however, an auction requirement could be applied to a double benchmark. Assuming a 5% auction imposed on CHP, for example, the following administrative double benchmark allocation would result:

$$.95\ ((.393 \text{ Mt/MWh} \times (\text{MWh Output}_E \times 1.035)) + (.066 \text{ Mt/MMBtu} \times \text{MMBtu Output}_T))$$

Under this approach, the extent to which a CHP plant will be required to purchase allowances at auction will vary with the plant's efficiency.

3. Bottoming Cycle CHP Requires Separate Treatment

EPUC/CAC propose to include bottoming cycle CHP in the separate CHP sector. As discussed above, within the CHP sector, a bottoming cycle facility without supplemental firing would be a zero emission generator and would require no allowance allocation for the production of electricity. With supplemental firing, however, the facility would require an allowance allocation.

Given these circumstances, how should allowances be allocated to bottoming cycle facilities? Two important points bear consideration. First, bottoming cycle or recycled energy plants *without supplemental firing* do not carry with them the same disincentive associated with topping cycle plants. This is because the installation of the steam turbine does not increase on-site emissions. Consequently, there is no disincentive to reverse through allocation; without supplemental firing, these plants are not “emitters” and thus would receive no allocation of allowances. Second, a double benchmark calculation cannot be used, because unlike a topping cycle CHP, a bottoming cycle facility does not produce thermal energy.

Under these conditions, a bottoming cycle plant without supplemental firing is zero-emitting and requires no allowance allocation. With supplemental firing, however, on-site emissions would increase. The initial goal, like topping cycle facilities, should be to determine whether there is any disincentive to installing bottoming cycle CHP that needs to be avoided. Assuming that the emissions rate produced by the CHP is lower than the average utility portfolio emissions rate, there is no specific disincentive. If, however, the rate is higher than the average utility rate (which averages zero emitting hydro, nuclear and renewables with fossil plants), but lower than the marginal emissions rate that the plant is displacing, a disincentive is created that should be corrected with allocation. One approach to correction would be to allocate allowances to bottoming cycle facilities using a marginal fossil emissions rate, whether the average system rate or some other measure.

Finally, the installation of bottoming cycle facilities results in a societal benefit, assuming the emissions are lower than the marginal fossil generation rate. Consequently, parties installing these plants should receive some form of credit to their industrial compliance obligation. As CARB further develops its industrial regulations under AB 32, the Commissions should work closely with the agency to ensure that bottoming cycle is given proper credit on the industrial side of the ledger.

E. Commissions Should Remove Existing Regulatory Barriers That Limit Full Deployment Of CHP

As discussed in Section IV.A above, CHP offers benefits as a material and proven GHG reduction measure. While ensuring GHG program treatment that will encourage these plants is critical, other existing barriers to CHP must be overcome.

As the CEC has recognized, CHP market potential can be as high as nearly 7,340MW of new CHP by 2020.[70] As the CEC has observed, however, departing load charges, lack of contracts, and resistance from utilities create barriers that limit the state from realizing the emission reduction potential of CHP.[71] To maximize GHG reductions from CHP, therefore, the Commission should consider the following policies:

- Portfolio set-aside for CHP power purchases;
- Reasonable pricing provisions for power purchases from CHP facilities;
- Removal of deployment barriers, including eliminating departing load charges; and
- Ease of interconnection and grid interface.

A short discussion of the each policy is provided below.

1. Portfolio Set-Aside for CHP Power Purchases

Currently, retail sellers are mandated to increase their purchases of renewables by at least 1% annually to reach 20% of utility/LSE portfolio by 2010.[72] Legislation to increase the renewable portfolio standard to 33% is under consideration. For this reason, the E3 model actually modeled a 33% RPS in its

70 *See* Attachment A to November 9, 2007 ALJ Ruling, at 8; EPRI, *Assessment of California CHP Market and Policy Options for Increased Penetration: PIER Collaborative Report* (CEC-500-2005-173).
71 CEC 2007 IEPR, at 206-211.
72 "Pursuant to the RPS Program, each retail seller is required each calendar year to procure, with some exceptions, a minimum quantity of electricity from eligible renewable energy resources as a percentage of total retail sales. This is generally known as the annual procurement target, or APT. Each retail seller is also required, with some exceptions, to increase its total procurement from eligible renewable energy resources by at least 1% of retail sales per year until it reaches 20%." See D. 08-02-008, at 5.

aggressive policy reference case.[73] Utilities have argued that compliance with the RPS is not currently feasible due to lack of renewable resources and other factors. CHP may offer a solution to transition from 20% to a 33% RPS in the long run.

Recent utility filings reflect much concern about the feasibility of achieving RPS mandates given the existing availability of renewable resources. As a result, there is concern about the feasibility of a 33% RPS or one that is even higher. In its recent modeling comments, for example, PG&E advocates a modeling sensitivity test that will "limit the renewable resource supply … given the uncertainty of achieving a 33% RPS level by 2020."[74] In a recent filing related to its application for approval of emerging renewable resource programs, PG&E again notes that demand for renewable resources continues to increase especially given the movement of states to adopt RPS requirements. As a result it observes that:

> *This has resulted in an approximate two-year backlog for wind turbines and solar photovoltaic cells, further impacting procurement efforts*.[75]

As PG&E notes, the increase in demand for renewable resources will impact rates:

> *It has been reported that over the last two years renewable prices have increased up to 50 percent in the West, while doubling in the Northeast, Mid-Atlantic, and the Plains states*.[76]

SCE's comments on GHG modeling issues also discuss the scarce supply of renewable resources.[77] Finally PG&E observes that as a result of the

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[73] E3 Documentation Overview, at 2.

[74] *See* PG&E Comments on E3 Model (dated January 3, 2008), at 11.

[75] *See* Response of PG&E to the Questions of ALJ DeBerry Issued October 11, 2007 in A.07-07-015 (dated October 23, 2007), at 4.

[76] *Id*. (citing *Clean Energy Can't Meet Growing Demand*, Paul Davidson, USA Today, October 4, 2007).

[77] SCE Comments on Modeling (dated January 3, 2008), at 10, 20.

renewable resource shortage, California utilities are seeking procurement opportunities in remote locations which often face transmission issues.[78]

PG&E's comments and to some degree SCE's comments demonstrate a need for a transitional solution to these problems to mitigate ratepayer costs while continuing to promote low carbon purchases. A reasonable transitional solution would be to allow qualifying CHP to fulfill utility requirements within a certain percentage of the 13% stretch from 20-33%. Acknowledging that 1 MWh of CHP generation does not yield the same level of reduction as 1 MWh of renewable generation, CHP MWh could be counted as some fraction of a renewable MWh. The fraction could be determined by determining reduction equivalency between renewables and CHP, taking into account the emissions of firming power for renewables.

Taking this approach would benefit the utilities by making their task more realistically achievable on a transitional basis. It would also help ratepayers, recognizing that CHP is a lower cost carbon reduction tool than many other solutions. Finally, it would augment the state's CHP policy, sending a signal for CHP retention and additional development.

2. Reasonable Pricing Provisions for Power Purchases from CHP Facilities

CHP contracts with reasonable pricing provisions are critical to ensure the economic viability of CHP facilities. Despite the issuance of D.07-09-040, which adopted policies and pricing mechanisms utility purchases of QF power, QF policy remains unfinished business. While D.07-09-040 was issued last fall, the contentious development of utility-QF standard contracts continues. Without firm contracts in place, existing CHP currently has no assurances from the Commission that any CHP will receive reasonable prices to ensure economic viability. While EPUC and CAC do not seek in these comments to contest or

78 *Id*.

litigate these issues in this Rulemaking, it is critical that the Commissions bear in mind the relationship of the QF decision with its future CHP policy.

Beyond the question of standard offer development lies the everpresent question of price. While, in theory, payments to QFs are supposed to reflect a utility's avoided costs, recent information suggests that the prices adopted in the Commission's decision are below a reasonable range. Appendix A demonstrates that the prices adopted in D.07-09-040 are much less than other current bellwethers such as the Commission's own market price referent price (MPR) for 2007 and the recently executed SCE Walnut Creek PPA. Notably, the all-in QF price at a natural gas price of $8/MMBtu ranges from $75.57-82.33/MWh while the 2007 MPR price is $89.50/MWh and the Walnut Creek PPA price is $125.44. Equally noteworthy is the fact that the capacity factor required in the 2007 MPR and the Walnut Creek PPA is much lower. While the capacity factor percentage for QFs is 95% during peak hours and 90% for off-peak hours, the capacity factor is 76% for the 2007 MPR and 45.66% for the Walnut Creek PPA. In short, comparing QF pricing options with that of the MPR and other contracts reveals that QF prices are not comparable to the prices afforded to other resources.

In addition to establishing an appropriate price for CHP power, the contractual provisions governing the sale to the utility must allow a reasonable opportunity for the CHP to actual earn the full capacity and energy price adopted by the Commission. The utilities' advice letter filings presenting their standard offer contracts contain numerous provisions that will provide disincentives for CHP facility operation. The disincentives include the following:

- Scheduling requirements that are more onerous that those contained in affiliate agreements that would compel the CHP to operate inefficiently and render receipt of the full price improbable;
- Inflexible maintenance provisions and allowable hours for maintenance that encourage practices that could lead to less reliable facility operation or in the alternative assure payment less than the full price adopted by the Commission;

- Capacity measurement and payment structure provisions that minimize the monthly capacity that is deemed available from the facility; and
- Discriminatory treatment of climate change costs vis a vis affiliate agreements.

As the Commission develops its GHG policy, it must keep these disincentives in mind.

3. Elimination of Departing Load Charges

The imposition of departing load charges on customer generation departing load (CGDL) is a barrier that is currently under consideration in Phase III of the long-term procurement proceeding (R.06-02-013). As discussed in that proceeding but relevant here for context, the imposition of new procurement and cost allocation mechanism nonbypassable (NBC) charges unnecessarily burdens the very resources that increase reliability and minimize system load. In effect, the NBCs directly discourage the reliance on and use of on-site generation. Addressing this existing regulatory barrier would substantially ease project development burdens and encourage the development of new, reliable cogeneration facilities.

4. Ease of Interconnection and Grid Interface

As noted in the staff paper, the CEC's 2007 IEPR observes that interconnection rules make it harder for CHP to sell power delivered off-site.[79] As discussed in Section IV(C), larger CHP projects which are capable of exporting more power, have been forced to comply with CAISO interconnection tariffs. [80] The Commissions should reconsider the current regulations and maximize the authority provided by FERC to provide for state-administered interconnection for QF CHP plants.

[79] See Joint California Public Utilities Commission and California Energy Commission Staff Paper on GHG Regulation for Combined Heat and Power, at 11.

[80] D.07-09-040, at 122 ("*These new QFs shall interconnect to the utility under Rule 21*.").

V. THE COMMISSIONS' E3 MODEL DEMONSTRATES THAT CHP WILL BRING GHG REDUCTIONS AT LOW CARBON COST

Despite the inherent limitations of a model and the compromises struck on several issues, the E3 model provides useful information on the cost and environmental impact of different resources and policies. In particular, the E3 model provides guidance on the cost relationship between different resources and on the approximate scope of emission reductions different resources can provide. While useful as a rough tool, it is important to keep the model's limitations in mind. For example, for CHP, while the E3 model reflects the substantial emission reduction value and favorable economics associated with investment and reliance on CHP, it provides only a conservative estimate of these benefits. The model also does not accurately reflect the reality of the market in some instances largely due to the nature to the modeling process and/or the limited time afforded to the development of the model. These issues are discussed below.

A. E3 Model Demonstrates That Encouragement Of CHP Will Further State's Emission Reduction Efforts In A Cost-Effective Manner

The ALJ Ruling, issued on May 13, 2008, reveals that the

> *"purpose of the modeling effort in this proceeding is to produce a tool by which the key impacts of achieving emission reductions within the electricity sector under AB 32 may be quantified"*.[81]

It also states that the model

> *"seeks primarily to provide insights about the relative cost-effectiveness of GHG abatement measures available within the electricity sector, as well as the overall cost impacts of achieving GHG emission reductions of varying stringency within the 2020 timeframe*."

E3's model provides information regarding the relative cost effectiveness of different resources and a rough estimate of the total economic impact of using

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[81] ALJ Ruling Requesting Comments on Emission Reduction Measures, Modeling Results, and Other Issues; Incorporating Materials Into the Record; and Recommending Outline for Comments, at 4.

these measures. In doing so, the model reveals that CHP can not only provide the state with substantial emission reductions, but does so in a cost-effective manner.

1. E3 Model Demonstrates That CHP is a Cost-Effective GHG Reduction Measure

The E3 model results confirm that CHP is a cost-effective emission reduction tool. CHP benefits can be seen both in the ability of CHP to reduce the utility's cost of carbon and to produce reductions at the lowest cost per tonne among generating resources.

While E3's results reflect varying degrees of CHP benefit, they consistently have reflected a negative utility carbon cost in the aggressive policy or 33% RPS/High goals EE case ("High Goals Case").[82] In the reference case, E3 projects no increase in the CHP generation to serve increasing grid energy requirements. The model reveals that the addition of 4,378 MW of small and large CHP in the High Goals Case, however, could provide over 16% of total additional CO_2 reductions at a cost to the utilities of a ***negative*** $161/tonne CO_2e. In comparison, the model indicates that additional CSI resources could contribute less that 6% of the additional CO2 reductions at a higher cost to the utilities of -$106/tonne CO_2e.

In addition, E3's carbon reduction supply curve, which compares the cost using various measures of reducing a tonne of carbon, demonstrates that CHP is an economical emission reduction tool even at an allowance price of zero.[83] In contrast, the following resources *begin* to become economical only once the carbon market price reaches the prices listed:

- Biogas: $50/tonne
- Wind: ~$105/tonne

[82] *See* E3 May 6, 2008 Presentation, at Slide 16; E3 May 13, 2008 Presentation, at Slide 16. *See also* CPUC Presentation by Julie Fitch on May 2, 2008, at Slide 9.
[83] E3 April 21, 2008 Presentation, at Slide 62; E3 May 6, 2008 Presentation, at Slide 17; E3 May 13, Presentation, at Slide 17.

- Solar Thermal: ~$140/tonne
- Geothermal: ~$140/tonne
- Biomass: ~ $205/tonne

This demonstrates that, unlike CHP, the economics of many emission reducing resources will depend on a high carbon price in the market.

2. E3 Model Reflects Significant Emission Reductions That Can Be Provided By CHP

E3's model results demonstrate that emission reductions attributed to new CHP under 33% RPS/High goals EE case are 4.9 $MMTCO_2$.[84] These emissions reductions are based on the addition of new CHP in the amount that is comparable to the ***moderate*** market access scenario of the CEC's CHP market potential report.[85] Consequently, as discussed below in Section B, these savings do not reflect the highest CHP potential presented in the CHP report and suggest that additional CHP benefits may be achievable if provided the correct policy directives.

From a utility cost per metric ton ("tonne") perspective, CHP fare well when stacked against the other CO_2 emission reduction measures evaluated by the model. The cost per tonne from CHP under 33% RPS/High goals EE reference case is less than those costs associated with energy efficiency (EE) and renewables.[86] Moreover, the model results draw attention to the CO_2 reduction benefits that are currently being provided by existing CHP facilities. This embedded benefit and the additional model projected reduction of 4.9 $MMtCO_2$ per year represent two significant elements in cost effectively achieving the state's goal of reducing emissions by 174 $MMtCO_2$ by 2020.[87]

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84 E3 May 13, 2008 Presentation, at Slide 16.

85 *Compare* Assessment of California CHP Market and Policy Options for Increased Penetration (CHP Market Potential Report), at xi (forecasting total CHP market penetration of 4,376 MW).

86 E3 May 13, 2008 Presentation, at Slide 16.

87 CARB Final Early Action Report, at 2.

B. E3 Model Results Provide Conservative Estimate Of CHP Benefits

The E3 model reflects many of the benefits of CHP but provides only a conservative estimate of the benefits that can be conferred by encouragement of CHP. In particular,

- For the limited purpose of an electricity sector comparison model, the model overallocates CHP emissions to the electricity output;
- The model overestimates CHP capital costs; and
- The Aggressive Policy Reference Case does not reflect the full market potential of CHP as identified by the CEC.

In short, the CHP benefits are understated by the model results. Each of these issues is discussed below.

1. Reliance on The EPUC/CAC Method To Assign CHP Emissions Between Electric and Thermal Outputs Would Better Ensure Apples-to-Apples Comparison of CHP to Other Electric Generating Resources

Because CHP produces both thermal and electric energy and the E3 model is designed to primarily focus on the electric sector, there is a potential to significantly understate the CO_2 reduction benefits of CHP. In order for E3 to correctly perform its CO_2 emission reduction assessment, CHP CO_2 emissions must be allocated between thermal and electric output. Consequently, it is imperative that the CHP emissions assigned to the electric sector in the E3 model are consistent with the evaluation objectives and do not distort the true CO_2 reduction benefits of this resource. The E3 model results are based on an allocation to electric output that overstates the emissions from CHP; thus understating the total CHP CO_2 reduction benefits.

The E3 model, in looking only at CHP electric output, appears to rely on an emission assignment method that “splits” the total CO_2 emission reduction benefit between electric and thermal outputs. Because the E3 model does evaluate CO_2 emission reductions related to thermal benefit, the model does not reflect the total CHP CO_2 reduction benefit.

For purposes of providing regulators with an accurate picture of the CHP CO_2 reduction benefits with in the E3 modeling limitations, EPUC/CAC has provided a better approach to allow an apples-to-apples comparison of electric resources. The method recommended by EPUC/CAC to E3 during the modeling process is based on the method historically employed by the Energy Information Administration (EIA) in which thermal emissions associated with a standard boiler are deducted from the total emissions of a CHP plant. The remaining emissions are attributed to electric generation. This approach ensures that the total efficiency benefits of CHP are not lost in the E3 modeling process that focuses solely on the electric side of the CHP equation. It also provides a simple, consistent and reasonable way to assure that that the total CO_2 reductions are reflected in the evaluation to allow for a fair comparison with other resources that generate only electricity.

Data submitted by EPUC/CAC to E3 in the modeling process illustrates the impact of differences in emission assignment methods. The data modeled a 49 MW electrical and 50 MW thermal CHP plant. The total CO_2 emissions from this facility would be 24.6 $MtCO_2$ per hour. Under the CARB methodology 16.4 $MtCO_2$ would be allocated to electric output (66.5%) and 8.2 $MtCO_2$ to thermal output (33.5%). In comparison, under the EPUC/CAC recommend method 13.4 $MtCO_2$ would be allocated to electric and 13.2 $MtCO_2$ to thermal.

2. E3 Model Understates Favorable CHP Economics

To ensure a fair comparison of CHP resources to a CCGT alternative in the model, the relationship between the costs of different resources must be accurately reflected. Relative to its capital costs for CCGTs, the E3 model appears to overstate the capital costs associated with new CHP installations. It is well understood that capital costs for electricity generation have risen dramatically, and these costs are admittedly difficult to determine. The cost of installation of a CCGT plant is currently an issue under debate in the ongoing review of the Market Price Referent in R.06-02-012. While the absolute value of either CHP or CCGT costs is difficult to peg, it is possible to ensure a fair relationship of CHP costs to CCGT costs in the model.

Delta Energy & Environment attempted to develop a ratio for CHP to CCGT costs in the E3 modeling process. Again, while absolute values for capital costs can be questioned, Delta arrived at a ratio between CHP and CCGT costs of 1.3 for a 49 MW facility. In contrast, the E3 model suggests a ratio of 1.43 for larger CHP (> 5 MW), suggesting that CHP costs are overstated in the model relative to CCGT costs.

3. "33% RPS/High Goals EE" Reference Case Does Not Reflect the Maximum CHP Potential

The E3 modeling effort focuses on the development of two base cases: a business as usual approach and an aggressive policy result (now called the 33% RPS/High Goals EE reference case). E3 draws information regarding CHP growth from the CEC's CHP Market Potential Report; this report, to EPUC/CAC's knowledge, provides the most recent forecast of CHP potential and growth in California. E3's reliance on this report is appropriate, but the assumptions used for the 33% RPS/High goals EE scenario remain conservative for CHP.

The Reference and 33% RPS/High goals EE cases rely on different assumptions regarding the use and reliance on different emission reduction tools, including CHP. The differences between these two reference cases are illustrated in the following chart, which is taken from E3's May 13 revised slides:[88]

[88] E3 May 13, 2008 Revised Slides, at 13.

Inputs	Business as Usual Reference Case	"33% RPS/High Goals EE" Reference Case
Energy Efficiency	Assume 16,450 GWh EE embedded in CEC load forecast	'High goals' EE scenario based on CPUC Goals Update Study and POU AB 2021 filings: 36,559 GWh
Rooftop Solar PV	847 MW nameplate of rooftop PV installed	3,000 MW nameplate of rooftop PV installed
Demand Response	5% demand response	5% demand response
Renewable Energy	20% (6,733 MW)	33% (12,544 MW)
Combined Heat and Power	292 MW nameplate behind-the-meter CHP No new large (>5MW) CHP	1,574 MW nameplate small CHP (< 5MW) 2,804 MW nameplate large CHP (> 5 MW)
Energy Efficiency	Assumes current levels of EE	Assumes high goals for EE

The E3 33% RPS/High Goals EE scenario reflects CHP growth estimated in the **moderate** market access scenario of the CEC's CHP Market Potential Report. As advocated in prior comments, however, to truly reflect an **aggressive** policy reference case, it is more reasonable to rely on the high deployment scenario of this report. Under the high deployment scenario, total CHP market penetration reaches 7,340 MW with certain incentives in place – nearly twice the value used in the E3 model.[89] According to the CEC CHP Market Potential Report, the high deployment case results in energy savings of up to 1,900 trillion Btu, customer net reduction in energy costs of $6 billion, and CO_2 emissions reduction of 112 million tons.[90] In short, if the goal of the model is to evaluate an aggressive policy scenario to maximize emission reductions in a cost-effective manner, its reliance on a moderate market analysis is not the best choice.

[89] *See* CHP Market Potential Report, at 2-18. The high deployment scenario assumes the existence of the following incentives: incentives existing in 2005, facilitation of the power export market, addition of a transmission and distribution support payment, a CO_2 reduction payment, the rapid development and deployment of advanced technology, and an increased willingness of customers to improve customer attitudes toward CHP investment opportunities.

[90] CEC CHP Market Potential Report, at 2-24.

C. E3 Model Not Easily Accessible Especially Given Time Constraint

E3 has produced a complicated spreadsheet model in a relatively short period of time. The development of the model has been rushed given the AB 32 timeline. Particularly due to the time restrictions, parties have not had an adequate time to evaluate the model or seek feedback from E3. All of the data used by the model may technically be "available" but understanding how it is used and locating the information is not an easy task. In short, there remain several issues that we continue to explore with E3 and will likely address in reply comments.

VI. FLEXIBLE COMPLIANCE MECHANISMS ARE CRITICAL TO COST-EFFECTIVE ACHIEVEMENT OF AB 32 GOALS

On April 25, 2008 CARB held a meeting to discuss cost containment measures. Its white paper on cost containment measures correctly observes that the "*interest in cost containment arises from the belief that an excessively wide range in allowance price or sudden sharp changes in allowance price (volatility) could be economically disruptive in the short term*." In the electricity sector, where the very thing regulated is a commodity of necessity, it is particularly important to make a wide variety of flexible compliance tools available. Moreover, given the nature of the commodity, a wide range of flexible compliance mechanisms should be available in the electricity sector regardless of their availability in other sectors. As CARB observes, the availability of cost-containment mechanisms will become increasingly important as the state promotes more aggressive emission reductions.[91] In particular, EPUC/CAC recommend consideration of following flexible compliance mechanisms to ease compliance in a cap-and-trade market system:

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[91] *See* Cost-Containment in Greenhouse Gas Cap-and-Trade System (CARB presentation dated April 25, 2008), at 5 (available at http://www.arb.ca.gov/cc/scopingplan/pgmdesign-sp/meetings/meetings.htm).

- Linkage
- Phased-In Compliance Periods
- Banking
- Borrowing
- Offsets

Each of these measures is discussed below. EPUC/CAC have no comments on price triggers, safety valves, penalties, alternative compliance payments and legal issues at this time.

A. Linkage

Linkage with other GHG programs is likely to limit leakage and thus promote environmental integrity. As discussed below, linkage can also have other impacts on the market that should be considered.

As the Climate Action Team (CAT) report notes, linkage is important to address leakage issues that can compromise environmental integrity:

> *"The primary weakness associated with implementing a market-based program in California is that it will be vulnerable to emissions "leakage." If the state implements the program without other states, there will be an incentive for activities that emit climate change emissions to shift to neighboring states to avoid the emissions cap. If this occurs, emissions may decline in the state, only to increase in other states."*[92]

As the CAT goes on to explain, "*a coordinated national approach to capping climate change emissions within the international framework would be the best approach for addressing this leakage problem*."[93] As the state creates a California-specific emission reduction program, therefore, it is important that linkage be considered to broaden the scope of the program.

Linkage, however, can also have a significant impact on the carbon market because it can link programs with different rules and allowance availability. As a result, it will be very important to consider these potential

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92 CAT Report, at 66
93 CAT Report, at 66

impacts to ensure limited price volatility consistent with AB 32's cost-containment principles.[94] An EPRI report highlights how California linkage with RGGI can, among other things, compromise environmental integrity and influence carbon market prices.[95] According to the report, due to RGGI's failure to include adequate protections against leakage, linking the California market to the RGGI market is likely to result in California complying entities purchasing large amounts of allowances in the RGGI market.[96] Since RGGI has certain price triggers in place, once carbon allowances reach a certain point, it stops tightening the region-wide allowance cap.[97] As a result, the EPRI report predicts that linkage with RGGI will drive down carbon prices in the California market while driving up prices in the RGGI market.[98] The example demonstrates that careful consideration of potential impacts of linkage is required to limit price volatility that could otherwise result.

B. Compliance Periods

As a general proposition, longer compliance periods offer greater flexibility and certainty to regulated entities, enabling better capital planning. Consequently, compliance periods should gradually increase in duration. EPUC/CAC recommend that the program initially have two compliance periods. A two-year "learn by doing" compliance period, with no auction, will provide an opportunity for regulated parties to gain experience with the regulations while bringing little risk to the market. Thereafter, the interests of certainty are best served by a 6 year compliance period, with graduating auction percentages reaching 60% by 2020.

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94 Ca. Health & Safety § 38501(h).

95 Program on Technology Innovation: Economic Analysis of California Climate Initiatives: An Integrated Approach, at 3-13

96 Id.

97 *Id*.

98 *Id.*

C. Banking

Banking should be widely encouraged. The Flexible Compliance Ruling indicates that "*[b]anking would allow an entity to buy and hold GHG emission allowances and/or credits across compliance periods . . . .*"[99] As CARB observes, banking provides flexibility in timing reductions which should mitigate volatility in allowances prices.[100] Importantly at the April 25, 2008 meeting CARB also noted that the lack of banking options between Phase I and II in the EU-ETS was a large contributing factor to the allowance price volatility that they experienced. CARB also explained that banking is a flexible compliance mechanism that is widely promoted by existing emission reduction programs including the Acid Rain Program, the EU-ETS (following Phase I), RGGI, and the WCI (reflected in draft recommendation).[101] Most importantly, CARB observes that "*[b]anking creates an incentive to make early reductions and encourages long-term commitment to the system from stakeholders*." CARB MAC also observes that banking can promote not only early reductions but more aggressive reduction efforts:

> *"Allowance banking enables firms to manage risk and provides an incentive for capped sources to over-comply in early periods as a way of "saving for a rainy day." Where allowed, banking has been used extensively, resulting in much greater early emissions reductions than would otherwise have taken place. Having allowances in the bank creates a hedge against any number of unexpected developments that could lead to higher-than-expected market prices. Had banking been allowed in the RECLAIM program, it is likely that post-combustion NOx controls might have been put in place earlier. Without the ability to bank allowances, firms had no incentive to install controls or reduce emissions earlier than necessary. Also, banked allowances from earlier periods could have*

[99] The Flexible Compliance Ruling indicates that "Banking would allow an entity to buy and hold GHG emission allowances and/or credits across compliance periods; borrowing would allow an obligated entity to use its allowances from a future compliance period to meet the obligation under a current compliance period." See Administrative Law Judges' Ruling Requesting Comments on Flexible Compliance Policies, at 7.

[100] CARB Cost-Containment White Paper (dated April 25, 2008), at 4; Cost Containment in a Greenhouse Gas Cap-and-Trade System (CARB presentation dated April 25, 2008), at Slide 9.

[101] Cost Containment in a Greenhouse Gas Cap-and-Trade System (CARB presentation dated April 25, 2008), at Slide 12.

> *facilitated compliance during the 2001 electricity crisis. Moreover, as learned in the EU ETS, the inability to bank allowances from one compliance period to the next may contribute to greater price volatility".*[102]

In short, to promote cost-effective and aggressive reductions, the Commission should recommend the availability of banking across compliance periods.

D. Borrowing

Borrowing is another flexible compliance mechanism that will allow flexibility in timing reductions.[103] As defined by CARB, borrowing would allow an entity to use allowances from a future compliance period in the current period.[104] Borrowing has not been widely encouraged in existing emission reduction efforts largely because some believe that it will discourage the long-term commitment to emissions reductions.[105] Borrowing rules, if carefully structured, should, however, be able to mitigate perverse incentives that borrowing could create. As a result, the Commission should consider borrowing, within compliance periods, in addition to other flexible compliance mechanisms. In the California market where investment time is much longer borrowing will be a critical tool that can facilitate investments to promote emissions reductions.

E. Offsets

As the MAC observes, the availability of offsets will be important to ensure system reliability and to limit GHG compliance costs. The MAC, in its report, supports the use offsets to promote and broaden the reach of emissions-reduction goals.[106] To mitigate concerns that the use of offsets will not result in real verifiable emission reductions, the MAC recommends the establishment of performance standards and protocols that would apply equally to in-state and

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[102] MAC Report, at 15.

[103] Cost Containment in a Greenhouse Gas Cap-and-Trade System (CARB presentation dated April 25, 2008), at Slide 9.

[104] Cost Containment in a Greenhouse Gas Cap-and-Trade System (CARB presentation dated April 25, 2008), at Slide 9.

[105] *See* Cost Containment in a Greenhouse Gas Cap-and-Trade System (CARB presentation dated April 25, 2008), at Slide 10.

[106] MAC Report, at 62.

out-of-state projects.[107] For administrative ease, the MAC recommends using a standards-approach over case-by-case review of individual projects. To address concerns that the availability of offsets detracts from the efforts to reduce emissions through technological improvements, the MAC notes that the better approach to promote long-term transformation in certain sectors is to employ direct technology-promoting policies.[108] Finally, the MAC disagrees with geographic limitations on the basis that it will impede California linkage with other programs.[109]

EPUC and CAC support the MAC's conclusions. California should develop the broadest offset program possible, taking into account the ability to verify reductions.

Respectfully submitted,

Evelyn Kahl

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June 2, 2008

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107 MAC Report, at 62-63.
108 MAC Report, at 65.
109 MAC Report, at 63-64.

Appendix A

Comparison of Generation Resource Costs Adopted/Filed Before the California Public Utilities Commission

	A	B	C	D	E	F	G	H
Line	Description	Date of Decision/Filing	Fixed Component ($/kW-yr)	Variable Component (Btu/kWh)	All-In Price At $8/MMBtu ($/MWh)	On-Line Date	Contract Term	Capacity Factor (Percent)
1	Market Price Referent (MPR) For 2006	Resolution E-4049 (12/14/06)	156.97	7,449	82.28	2007	10 years	78.98%
2	Firm Power Price for California QFs	D.07-09-040 (9/20/07)	91.97	8,014[1]	75.57[2]	2007	10 years	95% Peak/90% Off-Peak
3	Firm Power Price for California QFs	D.07-09-040 (9/20/07)	91.97	8,860[3]	82.33[4]	2007	10 years	95% Peak/90% Off-Peak
4	Market Price Referent (MPR) For 2007	Resolution E-4118 (10/4/07)	181.12	7,787	89.50	2008	10 years	76.00%
5	Walnut Creek PPA with SCE		207.60	9,192[5]	125.44	2013	10 years	45.66%

[1] Estimated SCE Average MIF Variable Component for April 2008 through March 2009 (excluding the 9,705 Btu/kWh Administrative Heat Rate) is 8,014 Btu/kWh.
[2] Calculation assumes a 91.67% Capacity Factor and a 8,014 Variable Component.
[3] Estimated SCE Average MIF Variable Component for April 2008 through March 2009 (including the 9,705 Btu/kWh Administrative Heat Rate) is 8,860 Btu/kWh.
[4] Calculation assumes a 91.67% Capacity Factor and a 8,860 Variable Component.
[5] Walnut Creek PPA Specifies a Full Load Heat Rate of 9,192 Btu/kWh.

Appendix B

Answers to Specific Questions in Identified Rulings

II. GENERAL ISSUES

Q.3 (5/13/08). 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.

Non-market-based tools to encourage emission reduction through CHP deployment, as recommended in Section IV.F, do not conflict with the implementation of a cap-and-trade program.

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

In general, the evaluation criteria for GHG regulatory issues should be expanded to include consideration of an alternative's (1) impact on short- and long-term supply availability and (2) promotion of the efficient use of fossil fuels. Section II.A discusses this issue further.

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

Coordination with CARB is important in establishing regulations to address CHP due to the interaction of electrical generation with an industrial process likely to be regulated by CARB. In developing a single CHP sector, as proposed in these comments, allowances for emissions related to topping cycle CHP must be contributed in part from the industrial sector. In addition, entities installing bottoming cycle CHP should receive some form of credit toward industrial compliance. These and other CHP-related issues should be carefully coordinated with CARB.

Q.12 (5/13/08). 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?

As discussed in Section VI, to the extent that California links with or becomes part of another cap and trade system a key issue will be to ensure that the rules are consistent across jurisdictions within the system. Linking programs with different rules could result in price volatility and compromised environmental integrity, among other issues.

Q.13 (5/13/08). 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.

As discussed in Section I, the detail sought by the Commissions in their most recent rulings outpaces CARB's AB 32 program development. The Commissions thus should aim for a general conceptual recommendation to CARB in August, with ongoing proceedings to refine the proposal as CARB's Scoping Plan begins to take shape. The general recommendation should include a method for general allowance allocation in the sector, a CHP allocation method, a general list of flexible compliance mechanisms that would benefit the electricity and CHP sectors, identification of compliance periods and specification of allocation frequency.

Q.1 (5/6/08). 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.

Flexible compliance mechanisms are critical to cost-effective achievement of the AB 32 goals. The electricity sector in particular, where the regulated commodity is deemed a necessity, should have a wide variety of compliance tools available. EPUC/CAC do not make a comprehensive proposal for flexible compliance rules here but instead discuss the merits of linkage, phased-in compliance, banking, borrowing and offsets. Further discussion of flexible compliance tools can be found in Section VI.

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

As noted above, EPUC/CAC do not make a comprehensive proposal for flexible compliance but note that flexible compliance mechanisms, including linkage to other programs, will be critical to the achievement of AB 32 mandates. It is virtually impossible at this point to analyze California's ability to link with other trading systems due to the substantial uncertainty at the federal and regional levels. Linkage with other GHG programs, however, is likely to limit leakage and thus promote environmental integrity.

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

It is difficult to speculate how the flexible compliance mechanisms might interact with one another. A cap-and-trade market with a wide range of flexible compliance mechanisms will, however, be important to facilitate cost-effective emission reductions and ensure system reliability is not threatened in the process.

> *Q.2 (5/6/08). 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 discussed in Section VI, to the extent that California links with or becomes part of another cap and trade system one key issue will be to ensure that the rules are consistent across jurisdictions within the system. Linking programs with different rules could result in price volatility and compromised environmental integrity. It is virtually impossible at this point to analyze California's ability to link with other trading systems due to the substantial uncertainty at the federal and regional levels.

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

Flexible compliance is critical to allow generators to minimize their costs of compliance. Controlling generator costs will benefit consumers by minimizing the potential for supply disruptions and cost. The ultimate goal in flexible compliance thus should be to maximize the number and flexibility of options such as banking, borrowing, linkage, and offsets.

III. ALLOWANCE ALLOCATION

A. Detailed Proposal

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

EPUC and CAC offer no proposal for the general allocation of allowances in the electricity sector, but focus their comments on allocation to CHP plants to encourage their operation and growth as a GHG reduction measure as described in Section IV.

Q.10 (4/16/08). 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, whether retained in the electricity sector or employed on an economy-wide basis, should be targeted to the development and deployment of GHG reduction technologies. In addition, any programs encouraging technology development must be designed to operate in a competition-neutral manner. This issue is discussed further in Section III.C

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

Q.8 (4/16/08). 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.

As discussed in more detail in Section III.A, allowances should not be allocated directly to retail providers. The point of allocation should be aligned with the point of regulation.

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

See Section III.B.

Q.10 (4/16/08). 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.

As a preliminary matter, the lawfulness of an allowance auction remains untested and should be determined within the scope of the broader, multi-sector program. To the extent that an auction is lawful and California's regulators mandate an auction for the electricity sector, auction revenues, should be retained in the electricity sector and targeted to the development and deployment of GHG reduction technologies. In addition, any programs encouraging technology development must be made available to all potential competitors on an equal basis. This issue is discussed further in Section III.C.

Q.11 (4/16/08). 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?

Regulators should target auction revenues to generally further GHG emission reductions, which would include promotion of energy efficiency and renewable power among other emission reducing measures.

Q.12 (4/16/08). 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.

EPUC and CAC do not support the use of auction revenues to reduce rates. Auction revenues, if any, should be used to further GHG reduction through the development and deployment of technology. If revenues are returned to subsidize rates, however, they should be used to offset the existing and mounting public purpose program charge burden. In addition, as observed in the

Staff CHP Paper, if revenues are returned to retail customers through their LSEs, a proportionate share should be returned to load served directly by CHP.

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

The disbursement of auction revenues is discussed in Section III.C.

C. Legal Issues

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

An aim throughout the Commissions' deliberations in designing a GHG program has been avoiding legal challenge to the program under the Dormant Commerce Clause (DCC) of the United States Constitution. The proposal for regulation of CHP emissions would allocate allowances to in-state topping cycle CHP using a double benchmark allocation. The allocation would cover emissions attributable to both thermal and electric CHP output. It proposes to allocate allowances to out-of-state CHP electricity delivered to the California grid using the electricity reference in the double benchmark formula for in-state CHP; emissions attributable to thermal output by an out-of-state CHP would not be regulated by California.

While in-state and out-of-state CHP will not be treated precisely the same, this treatment is not vulnerable to challenge under the Dormant Commerce Clause because the rationale for treatment lies in jurisdictional limitations.

DCC jurisprudence provides that states cannot regulate extraterritorially or directly regulate out-of-state entities.[1] As a result, California has only the authority to regulate those transactions which are directed to the state. California's authority to track and require compliance from out-of-state CHP is therefore limited to the emissions associated with power delivered to the California grid.

Under the EPUC/CAC proposal, in-state and out-of-state CHP would not be treated similarly. A statute that is facially-discriminatory is subject to

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[1] *United Haulers Association, Inc. v. Oneida-Herkimer Solid Waste Management Auth'y,* 127 S. Ct 1786 (2007)("*Although the Constitution does not in terms limit the power of States to regulate commerce, we have long interpreted the Commerce Clause as an implicit restraint on state authority, even in the absence of a conflicting federal statute*.")

strict scrutiny and will fail unless "*the discrimination is demonstrably justified by a valid factor unrelated to economic protectionism*."[2] Notably, DCC challenges have been sustained only where out-of-state commerce was restricted or more heavily taxed than in-state commerce.[3] In this case, the rationale for differential treatment is valid jurisdictional limitations. Moreover, the difference in treatment results in less regulation of out-of-state CHP when compared to in-state CHP. For these reasons, the proposal will not be vulnerable to DCC challenge.

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

It is unclear whether California possesses the legal authority to auction allowances, which is required to implement staff's preferred auction-based approach.[4] As a preliminary matter, AB 32 provides no explicit authority for auction. In addition, an auction fails to meet the criteria of a valid tax or regulatory fee. Accordingly, any current attempt by California to auction allowances would be vulnerable to legal challenge. For further discussion of this issue, see Section III.B.1

> *Q.4 (4/16/08). Does any of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your*

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[2] *Wyoming v. Oklahoma*, 502 U.S. 437, 454 (1992); *Oregon Waste Systems, Inc.,* 511 U.S. at 93; *Maine*, 477 U.S. at 131.

[3] The Supreme Court has clarified, for example, that a law is discriminatory if it "*tax[es] a transaction or incident more heavily when it crosses state lines than when it occurs entirely within the State*." *Oregon Waste Systems, Inc. v. Dept. of Environmental Quality of the State of Oregon, et al*., 511 U.S. 93, 99 (1994). Accordingly, an Oregon statute, which imposed a higher surcharge per ton for disposal of solid waste generated in Oregon than for waste generated in other states, was found to be facially discriminatory. *Oregon Waste Systems, Inc.,* 511 U.S. at 93. A Maine statute, which banned the importation of live baitfish into the state, was also deemed facially discriminatory. *See Maine v. Taylor*, 477 U.S. 131, 138 (1986). Finally, a state statute that restricted out-of-state wineries from selling wine directly to in-state consumers was found facially discriminatory. Granholm v. Heald, 544 U.S. 460, 466 (2005).

[4] D.08-03-018 did not address the legality of an auction: "*Parties disagree as to whether ARB has authority under current statutes to conduct auctions of allowances.[4] This is not an issue that we should, or need to, resolve. If ARB concludes that it needs additional authority in order to conduct auctions and distribute auction proceeds consistent with our recommendations, we recommend that ARB seek additional legislation. We would support ARB in this endeavor*." *See* D.08-03-018, at 95.

opening comments, raise any other legal concerns? If so, please explain in full with citations to specific relevant legal authorities. Also, explain if and, if so, how, the allocation option(s) could be modified to avoid such legal concerns.

EPUC/CAC have no view on this issue at this time.

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

N/A

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

N/A

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

N/A

IV. FLEXIBLE COMPLIANCE

A. Detailed Proposal

Q.1 (5/6/08). 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.

Flexible compliance mechanisms are critical to cost-effective achievement of the AB 32 goals. The electricity sector in particular, where the regulated commodity is deemed a necessity, should have a wide variety of compliance tools available. EPUC/CAC do not make a comprehensive proposal for flexible compliance rules here but instead discuss the merits of linkage, phased-in compliance, banking, borrowing and offsets. Further discussion of flexible compliance tools can be found in Section VI.

B. Scope of Market and Related Issues

Q.1a (5/6/08). Discuss how your proposal would affect the environmental integrity of the cap, California's ability to link with other trading systems, and administrative complexity.

As noted above, EPUC/CAC do not make a comprehensive proposal for flexible compliance but note that flexible compliance mechanisms, including linkage to other programs, will be critical to the achievement of AB 32 mandates. In particular, as discussed in Section VI.A, linkage with other GHG programs is likely to limit leakage and thus promote environmental integrity.

Q.1b (5/6/08). Address how your various recommendations interact with one another and with the overall market and describe what kind of market you envision being created.

It is difficult to speculate how the flexible compliance mechanisms might interact with one another. A cap-and-trade market with a wide range of flexible compliance mechanisms will, however, be important to facilitate cost-effective emission reductions and ensure system reliability is not threatened in the process.

Q.1c (5/6/08). Describe and specify how unique circumstances in the electricity market may warrant any special consideration in crafting flexible compliance policies for a multi-sector cap-and-trade program.

Since the very thing regulated in the electricity sector is a commodity of necessity, it is particularly important to make a wide variety of flexible compliance tools available to ensure cost-effective emission reductions. This is discussed further in Section VI.

Q.1d (5/6/08). If your recommendations are based on assumptions about the type and scope of a cap-and-trade market that ARB will adopt, provide a description of the anticipated market including sectors included, expected or required emission reductions from *the electricity sector, and the role that flexible compliance mechanisms serve in the market, e.g., purely cost containment, catalyst for long-term investment, and/or protection against market failures.*

A cap-and-trade program presents the highest potential for cost-effective GHG emissions reductions to meet AB 32 goals. These comments assume that California will implement a multi-sector cap-and-trade program, including at a minimum, electricity and industrial sectors. The success of the cap-and-trade program will turn, in large part, on the program's scope, and including all regulated sectors will enhance market liquidity and better serve the state's reduction goals. An expansive cap-and-trade program will also ensure parity between regulated sectors.

It is difficult, without the benefit of CARB's Scoping Plan, to recommend any level of cap or reductions for the electricity sector. The electricity sector should not, however, be disproportionately burdened. Moreover, the cap should not be so restrictive as to risk disruptions in supply.

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

A cap-and-trade market that provides all participants a full range of flexible compliance options will best serve the state's interests in cost-effective GHG reductions. As discussed in Section VI above, however, given the nature of the electric sector a wide range of flexible compliance mechanisms should be available regardless of their availability in other sectors. While it is difficult to make specific recommendations in this regard in light of the status of CARB's Scoping Plant, the Commissions can make a general recommendation. Those recommendations should propose to maximize the types of flexible compliance mechanisms available to participants, as well as the scope of permitted trading and offsets.

Q.5 (5/6/08). Why or why not? Should the market for GHG emission allowances and/or offsets be limited to entities with compliance obligations, or should other entities such as financial institutions, hedge funds, or private citizens be allowed to participate in the buying and selling of allowances and/or offsets? If non-obligated entities are allowed to participate in the market, should the trading rules differ for them? If so, how?

Allowances should be allocated administratively only to those entities with a compliance option to ensure sufficient availability. Limiting the availability to regulated entities by broadening the allocation to other parties places unnecessary risks of supply adequacy.

C. Price triggers and Other Safety Valves

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

EPUC/CAC have no view on this issue at this time.

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

EPUC/CAC have no view on this issue at this time.

D. Linkage

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

Yes. California should maximize the geographic scope of the program to include a wide range of acceptable tradable units, provided uniform standards are employed. Given the global nature of GHG emissions, broadening the scope of trading and offsets could provide the opportunity to achieve GHG reduction goals at a lower cost.

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

Linkage can have a significant impact on the carbon market because it can link programs with different rules and allowance availability. This issue is discussed further in Section VI.A.

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

EPUC/CAC have no view on this issue at this time.

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

The answer to this question will depend upon the standards employed in other carbon trading programs. Where there are uniform rules, such as a western region program, there would be no need to treat allowances from other states as offsets. Where the rules are not uniform, however, it may be reasonable to treat the allowances or credits as offsets. Once again, it is too early in the program development to provide a meaningful comment.

E. Compliance periods

Q.12 (5/6/08). 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 program should initially have two compliance periods. The first two-year period should allow regulated entities to "learn by doing," as the EU-ETS provided in Phase I. Following this two year period, a seven-year compliance period should be implemented to maximize regulatory certainty and promote investment. Within these compliance periods, allowances should be allocated annually. This proposal is discussed in further detail in Section VI.B.

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

EPUC/CAC have no view on this issue at this time.

F. Banking and Borrowing

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

To promote cost-effective and aggressive reductions, the Commission should recommend the availability of banking across compliance periods. This issue is discussed in more detail in Section VI.C.

Q.15 (5/06/08). Should limitations be placed on banking aimed at preventing or limiting market participants' ability to "hoard" allowances and offsets or distort market prices?

EPUC/CAC have no view on this issue at this time.

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

As discussed in Section VI.D, the Commission should adopt borrowing in addition to other flexible compliance mechanisms. In the California market, where investment time is much longer due to permitting requirements, borrowing will be a critical tool that can facilitate investments to promote emissions reductions.

G. Penalties and Alternative Compliance Payments

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

EPUC/CAC have no view on this issue at this time.

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

EPUC/CAC have no view on this issue at this time.

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

EPUC/CAC have no view on this issue at this time.

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

EPUC/CAC have no view on this issue at this time.

H. Offsets

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

The availability of offsets will be important to ensure system reliability and to limit GHG compliance costs. As such, California should develop the broadest offset program possible, taking into account the ability to verify reductions. This issue is discussed further in Section VI.E.

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

Any verifiable and permanent GHG reductions not otherwise treated as allowances should be accepted as offsets. There should not be geographic limitations as this will impede California linkage with other programs. This is discussed further in Section VI.E.

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

Yes. Any voluntary reduction outside the scope of California's cap and trade program should be accepted as an offset, again with the goal of minimizing compliance costs and price increases to consumers.

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

No. Assuming reductions are permanent and verifiable, there should be no limit to the quantity of offsets. A tonne of GHG reduction is a tonne of GHG reduction, regardless of its location or purpose. No discount should be taken to offsets if those offsets meet the standards set for California's cap-and-trade program.

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

EPUC/CAC support the use of performance standards and protocols to ensure that offsets result in real verifiable emissions reductions. This issue is discussed in Section VI.E.

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

A tonne of GHG reduction is a tonne of GHG reduction, regardless of its location or purpose. No discount should be taken to offsets if those offsets meet the standards set for California's cap-and-trade program.

I. Legal Issues

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

EPUC/CAC have no view on this issue at this time.

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

EPUC/CAC have no view on this issue at this time.

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

EPUC/CAC have no view on this issue at this time.

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

EPUC/CAC have no view on this issue at this time.

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

N/A

V. Treatment of CHP

A. Detailed Proposal

Q1 (5/1/08). 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.

EPUC/CAC's detailed proposal on regulating GHG emissions from CHP facilities is discussed in Section IV.

B. Regulation of CHP GHG Emissions

> *Q2 (5/1/08). Should GHG emissions from CHP systems be regulated in one sector? If so, which one? How?*

Yes. GHG emissions from CHP systems should be regulated in a single CHP sector. For both topping and bottoming cycle CHP, the point of regulation should be the deliverer, to ensure the same point of regulation for all electricity producers. For topping cycle CHP, the system should include the single facility that produces both thermal and electrical output. For bottoming cycle CHP, the system included in the CHP sector should include only those facilities related solely to the production of electrical energy; the industrial process underlying the production of waste heat should remain in an industrial sector. These issues are discussed in Section IV.

Allowances should be brought into the sector from both the electricity and industrial sector caps. Allowances should be allocated to topping cycle CHP using a double benchmark method, with limited adjustments for plant vintage and avoided grid losses. There is no reason to differentiate point of regulation among grid deliveries, on-site electrical deliveries and on-site thermal deliveries. Allowances should be allocated to a bottoming cycle facility only if the facility emits GHG from supplemental firing; in this case, allowances should be allocated using the electric reference from the double benchmark formula or general allocation factor used for electric generation.

> *Q3 (5/1/08). 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?*

See response to Q2 (5/1/08).

> *Q4 (5/1/08). For out-of-state CHP systems, how should GHG emissions attributed to the electricity delivered to the California grid be regulated? If part of the electricity sector, should the deliverer of the CHP-generated electricity delivered to the California grid be the point regulation? (These questions are based on our view that, for out-of-state CHP systems, only emissions attributed to electricity delivered to California, and not attributed to other electricity or the thermal output, are subject to AB 32.)*

Emissions of out-of-state CHP systems should be tracked in a separate CHP sector like the emissions of in-state CHP.

> *Q5 (5/1/08). Should CHP units be placed in different sectors based on CHP unit capacity size?*

All CHP should be regulated in a single separate CHP sector as discussed in Section IV.B. The only size distinction that should be considered is whether CHP plants that fall below the CARB threshold of 25,000 tCO_2 should be included.

> *Q6 (5/1/08). Should any of the options for assigning the emissions of a CHP unit to one or more sectors be rejected because it might violate the dormant Commerce Clause?*

Assignment of emissions to one sector over another does not raise Dormant Commerce Clause issues because it does not result in the differential treatment of in-state and out-of-state entities.[5]

> *Q7 (5/1/08). 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?*

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[5] *Oregon Waste Systems, Inc. v. Department of Environmental Quality of Oregon*, 511 U.S. 93, 99 (1994).

As discussed in Section IV.D and F, topping and bottoming cycle CHP facilities should be treated differently. See response to Q2(5/1/08).

> *Q8 (5/1/08). Should the sectors used for GHG regulation be different for topping cycle and bottoming cycle CHP units?*

No. The emissions of both topping and bottoming cycle facilities should be tracked in a separate CHP sector. Bottoming cycle emissions, however, should be defined as only those emissions generated from supplemental firing of the waste heat boiler.

> *Q9 (5/1/08). 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?*

Yes. Any CHP plant that emits GHG should, like all other electric generators, be included in a cap-and-trade program. To the extent the CHP plants emissions for thermal output would otherwise be regulated by CARB as a part of the industrial facility, all outputs and emissions should be included in the cap-and-trade system. If the thermal production would not otherwise be regulated, however, because the industrial facility is somehow exempt from GHG regulation by CARB, an adjustment may need to be made to exclude regulation of some portion of the CHP plants emissions. Provided a 25,000 tonne threshold is used, it is very unlikely that any such adjustment would be required.

> *Q10 (5/1/08). 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?*

CHP, like any other electricity generator, is an emitter. For electricity delivered to the grid, using the same point of regulation ensures consistency among competitors in the manner of regulation. It should, however, be included in a separate sector with separate allowance allocation rules.

> *Q11(5/1/08). 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?*

Yes, for topping cycle facilities, all electricity will be generated using a single facility, whether the output is used on site or delivered to the grid. There is no plausible reason to make a distinction. It may be reasonable, however, to consider exemption of some or all of the on-site portion of electricity from regulation as a means of providing an incentive to CHP operation and development.

Q12 (5/1/08). 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?

The emissions of CHP should not be tracked in separate sectors. As discussed in Section IV, it is critical that the emissions of CHP be tracked in a separate CHP sector for administrative ease and to ensure recognition of its full emission reduction potential.

Q13 (5/1/08). 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?

Allowance allocation to CHP is discussed in detail in Section IV. See also response to Q2.

Q14 (5/1/08). If allowances are allocated administratively to CHP units, should the allocations take into account increased efficiency of CHP? If so, how?

Yes. An administrative allocation should take into account the increased efficiency of CHP. To reward CHP for primary energy savings, allowances should be allocated using a double-benchmarking standard. Under a double benchmarking, CHP's actual emissions would be compared to the emissions that would have resulted had the same amount of electric and thermal energy been produced using stand-alone electric and heat production facilities. To the extent the plant's actual emissions are less than the benchmark emissions, CHP has produced "primary energy savings" (PES) equal to the difference and should be rewarded for these savings.

Q15 (5/1/08). 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?

There are advantages to regulating CHP in a single sector. First, from the standpoint of both regulators and regulated entities, treating the emissions from a single plant in a single sector simplifies reporting, tracking and compliance. Second, by tracking in a single sector, the Commissions can ensure the efficiency of CHP plants and track the GHG reduction progress and benefits. As discussed in more detail in Section IV(D), the creation of a separate CHP sector to track all thermal and electric emissions is necessary to fairly capture the full societal benefits of CHP.

Q17 (5/1/08). 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?

Investment in topping cycle CHP reduces global emissions associated with electric and thermal production but increases the investor's direct on-site emission responsibility. As a result, allowance allocation can discourage the operation and development of topping cycle CHP facilities. See response to Q2 and Section IV. Using double benchmarking to allocate allowances mitigates the disincentive by rewarding a facility for primary energy savings.

Q24 (5/1/08). Would including all of CHP in cap and trade create a disincentive if natural gas is not regulated under cap and trade?

<u>EPUC/CAC do not understand the question.</u>

C. CHP As An Emission Reduction Measure

Q16 (5/1/08). Should CHP be considered an emission reduction measure under AB 32? Why or why not?

AB 32 requires that the state achieve "*the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions . . . by 2020 . . . .*"[6] Existing CHP provides at least 7.0 MMtCO2e and new CHP is capable of providing an additional 9-11MMtCO2e. E3 modeling has also demonstrated that, from a utility carbon cost perspective, CHP is among the most cost effective generation resources. These factors together demonstrate that an electricity policy that fails to adequately recognize the contribution of existing and new CHP resources to GHG reduction efforts will not fulfill the mandates of AB 32. The benefits of CHP are discussed in more detail in Section IV(A).

Q18 (5/1/08). Should ARB and/or the Commissions consider policies or programs to encourage installation of CHP for GHG reduction purposes? Why or why not?

The Commission should consider a policy to encourage the installation of CHP for GHG reduction purposes. Employing a double benchmark method for GHG allowance allocation would further that purpose, as would the proposed policies discussed in Section IV(E).

Q19 (5/1/08). Should CHP have an efficiency threshold in order to qualify as an emission reduction measure? If so, why?

[6] Ca Health & Safety Code § 38561.

Yes. The Commissions must be certain that CHP is actually producing a GHG reduction benefit compared to the alternative of stand-alone production of the CHP outputs. A double-benchmarking standard should be used to determine whether CHP is efficient. The use of a double-benchmarking standard to focus incentives on efficiency CHP is discussed in Section Double benchmarking, in general, contemplates a comparison of a topping cycle CHP plant's actual emissions to the emissions that would have resulted had the same amount of electric and thermal energy been produced using stand-alone electric heat production facilities. To derive the double benchmark, a plant's electric output would be multiplied by an electric reference emissions rate, and the plant's thermal output would be multiplied by a thermal reference emissions rate. This benchmark could be compared to a CHP facility's actual electric and thermal emissions. To the extent the plant's actual emissions are less than the benchmark emissions, a CHP has produced "primary energy savings" (PES) equal to the difference and should qualify as an emissions reduction measure.

Q20 (5/1/08). Which of the proposed methods best achieves the objectives of an efficiency threshold and why is it the best? Is there a superior method not proposed by staff and why is it superior?

See Answer to Q19 (above)

Q21 (5/1/08). What should the minimum efficiency threshold be (in terms of % savings) to qualify as an emissions reduction measure and why is that the appropriate minimum efficiency threshold?

See Answer to Q19 (above)

Q23 (5/1/08). Should the Commissions pursue policy or programmatic measures to overcome some of the barriers to CHP deployment?

The Commission should pursue policy and programmatic measures to overcome existing barriers to CHP deployment. Specific proposals are discussed in Section IV(E).

D. Legal Issues

Q22 (5/1/08).   Are there other legal and regulatory barriers to CHP implementation in California that should be considered with respect to GHG regulation? If so, please explain in full with citations to specific relevant legal authorities. Also explain if and, if so, how the barriers could be avoided.

There currently exist several regulatory barriers that prevent the full realization of CHP benefits. To minimize these regulatory barriers and proposals to minimize them are discussed in Section IV(E).

VII. Modeling Issues

A. Methodology

Q.8 (5/13/08). 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?

Despite the inherent limitations of a model and the compromises struck on several issues, the E3 model provides useful information on the cost and environmental impact of different resources and policies. In particular, the E3 model reveals that encouragement of CHP will further the state's emission reduction efforts in a cost-effective manner. While useful as a rough tool, it is important to keep the model's limitations in mind. For example, while the E3 model reflects the substantial emission reduction value and favorable economics associated with investment and reliance on CHP, it provides only a conservative estimate of these benefits. The model also does not accurately reflect the reality of the market in some instances largely due to the nature of the modeling process and/or the limited time afforded to the development of the model. These issues are discussed in more detail in Section V.

B. Inputs

Q.9 (5/13/08). 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 E3 model reflects many of the benefits of CHP but provides only a conservative estimate of the benefits that can be conferred by encouragement of CHP. In particular,

- For the limited purpose of an electricity sector comparison model, the model overallocates CHP emissions to the electricity output;
- The relationship of installation costs for CCGT and CHP is distorted; and
- The Aggressive Policy Reference Case does not reflect the full market potential of CHP as identified by the CEC.

In short, the CHP benefits that can be captured by California likely are much greater than reflected in the model. Each of these issues is discussed in Section V.B. In addition, we continue to explore other modeling issues with E3.